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100% Renewable Energy Transition

Pathways and Implementation

Edited by
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Preface to "Renewable Energy Transition: Pathways and Implementation"

1. Introduction to this Special Issue

Energy markets are already undergoing considerable transitions to accommodate new (renewable) energy forms, new (decentral) energy players, and new system requirements, e.g., flexibility and resilience [1]. Traditional energy markets for fossil fuels are therefore under pressure [2], while not yet fully mature (renewable) energy markets are emerging [3]. As a consequence, investments in large-scale and capital intensive (traditional) energy production projects are surrounded by high uncertainty, and are difficult to hedge by private entities as they might result in stranded assets [4]. Traditional energy production companies are transforming into energy service suppliers and companies aggregating numerous potential market players are emerging, while regulation and system management are playing an increasing role. To address these increasing uncertainties and complexities, economic analysis, forecasting, modeling, and investment assessment require fresh approaches and views. Novel research is thus required to simulate multiple actor interplays and idiosyncratic behavior [5]. The required approaches cannot deal with energy supply only, but need to include active demand and cover systemic aspects. Energy market transitions challenge policy-making. Market coordination failure, the removal of barriers hindering restructuring, and the combination of market signals with command-and-control policy measures are some of the new aims of policies [6].

The aim of this Special Issue is therefore to collect research papers that address the above issues using novel methods from any adequate perspective, including economic analysis, modeling of systems, behavioral forecasting, and policy assessment. The issue will include, but is not be limited to

- Local control schemes and algorithms for distributed generation systems;
- Centralized and decentralized sustainable energy management strategies;
- Communication architectures, protocols, and properties of practical applications;
- Topologies of distributed generation systems improving flexibility, efficiency, and power quality;
- Practical issues in the control design and implementation of distributed generation systems;
- Energy transition studies for optimized pathway options aiming for high levels of sustainability.

2. Individual Articles

2.1. Analysis of Case Studies

The Special Issue includes various case studies examining the implementation of 100% renewable scenarios. Brown et al. [7] investigate different decarbonization pathways for the European energy system considering the interactions of the electricity, heating, transport, and industry sector to avoid inefficient investments due to false sectoral prioritization caused by separate consideration. Germany´s energy sector, including power, heat, and transportation, is modelled on a Federal State resolution by Bartholdsen et al. [8] in order to derive cost-efficient pathways and technology mixes for different levels of decarbonization until 2050. The paper of Marczinkowski et al. [9] compares the pathways of three European islands in order to identify features, namely, e.g., smart grid, sector integration, local conditions, and balancing technologies, that play a major role in achieving the goal of a 100% renewable energy system for these islands and comparable regions.

Leaving Europe, Lawrenz et al. [10] analyze three different pathways for the Indian energy system until 2050 using a linear, and cost-minimizing, global energy system model. The scenarios range from a conservative New Policies scenario by the IEA to a 100% renewable energy source pathway. Sarmiento et al. [11] examine the effect of current national renewable targets and climate goals on the Mexican energy system and examines the cost optimal share of renewables.

2.1.1. Sectoral Interactions as Carbon Dioxide Emissions Approach Zero in a Highly-Renewable European Energy System—Brown et al. [7]

In this paper, interactions between the electricity, heating, transport, and industry sector are examined for the period after 2030 in an existing openly available, hourly-resolved, per-country, and highly-renewable model of the European energy system, PyPSA-Eur-Sec-30, that includes electricity, land transport, and space and water heating. A parameter sweep of different reduction targets for direct carbon dioxide emissions is performed, ranging from no target down to zero direct emissions. The composition of system investments, the interactions between the energy sectors, shadow prices, and the market values of the system components are analyzed as the carbon dioxide limit changes. Electricity and land transport are defossilized first, while the reduction of emissions in space and water heating is delayed by the expense of new components and the difficulty of supplying heat during cold spells with low wind and solar power generation. For deep carbon dioxide reduction, power-to-gas changes the system dynamics by reducing curtailment and increasing the market values of wind and solar power. Using this model setup, cost projections for 2030, and optimal cross-border transmission, the costs of a zero-direct-emission system in these sectors are marginally cheaper than today's system, even before the health and environmental benefits are taken into account.

2.1.2. Pathways for Germany's Low-Carbon Energy Transformation Towards 2050—Bartholdsen et al. [8]

Like many other countries, Germany has defined goals to reduce its CO2-emissions following the Paris Agreement of the 21st Conference of the Parties (COP). The first successes in decarbonizing the electricity sector were already achieved under the German Energiewende. However, further steps in this direction, also concerning the heat and transport sectors, have stalled. This paper describes three possible pathways for the transformation of the German energy system until 2050. The scenarios take into account current climate politics on a global, European, and German level and also include different demand projections, technological trends, and resource prices. The model includes the sectors power, heat, and transportation and works on a Federal State level. For the analysis, the linear cost-optimizing Global Energy System Model (GENeSYS-MOD) is used to calculate the cost-efficient paths and technology mixes. They find that a reduction of CO2 of more than 80% in the less ambitious scenario can be welfare enhancing compared to a scenario without any climate mitigating policies. Even higher decarbonization rates of 95% are feasible and needed to comply with international climate targets yet related to high effort in transforming the subsector of process heat. The different pathways depicted in this paper render chances and risks of transforming the German energy system under various external influences.

2.1.3. Transitioning Island Energy Systems: Local Conditions, Development Phases, and Renewable Energy Integration—Marczinkowski et al. [9]

Islands typically have sensitive energy systems depending on natural surroundings, but innovative technologies and the exploitation of renewable energy (RE) sources present opportunities like self-sufficiency, but also challenges, such as grid instability. Samsø, Orkney, and Madeira are in the transition to increase the RE share towards 100%; however, this is addressed in different ways depending on the local conditions and current development phases in the transition. Scenarios focusing on the short-term introduction of new technologies in the energy systems are presented, where the electricity sector is coupled with the other energy sectors. Here, both smart grid and sector-integrating solutions form an important part in the next 5–15 years. The scenarios are analyzed using the modeling tool EnergyPLAN, enabling a comparison of today's reference scenarios with 2030 scenarios of higher RE share. By including three islands across Europe, different locations, development stages, and interconnection levels are analyzed. The analyses suggest that the various smart grid solutions play an important part in the transition; however, local conditions, sector integration, and balancing technologies even more so. Overall, the suggestions complement each other and pave the way to reach 100% RE integration for both islands and, potentially, other similar regions.

2.1.4. Exploring Energy Pathways for the Low-Carbon Transformation in India—A Model-Based Analysis—Lawrenz et al. [10]

With an increasing expected energy demand and current dominance of coal electrification, India plays a major role in global carbon policies and the future low-carbon transformation. This paper explores three energy pathways for India until 2050 by applying the linear, cost-minimizing, global energy system model (GENeSYS-MOD). The benchmark scenario "limited emissions only" (LEO) is based on ambitious targets set out by the Paris Agreement. A more conservative "business as usual" (BAU) scenario is sketched out along the lines of the New Policies scenario from the International Energy Agency (IEA). On the more ambitious side, they explore the potential implications of supplying the Indian economy entirely with renewable energies with the "100% renewable energy sources" (100% RES) scenario. Overall, the results suggest that a transformation process towards a low-carbon energy system in the power, heat, and transportation sectors until 2050 is technically feasible. Solar power is likely to establish itself as the key energy source by 2050 in all scenarios, given the model's underlying emission limits and technical parameters. The paper concludes with an analysis of potential social, economic and political barriers to be overcome for the needed Indian low-carbon transformation.

2.1.5. Analyzing Scenarios for the Integration of Renewable Energy Sources in the Mexican Energy System—An Application of the Global Energy System Model (GENeSYS-MOD)—Sarmiento et al. [11]

This paper uses numerical techno-economic modelling to analyze the effect of current national renewable targets and climate goals on the cost and structural composition of the Mexican energy system. For this, the authors construct a scenario base analysis to compare current policies with two alternative states of the world—one without climate policies and one attaining full decarbonization. Furthermore, an additional iterative routine allows them to estimate the cost-optimal share of renewable technologies in the energy sector and the effect that deviating from this share has on total discounted system costs, emissions, and the structure of the energy mix. In general, model results exhibit three key insights: (1) a marked dependence of the energy system on photovoltaics and natural gas; (2) the 2050 cost-optimal share of renewables for the production of electricity, transportation and industrial heating is respectively 75%, 90%, and 5%, and (3) as national renewable targets for the power sector are lower than the cost-optimal share of renewables, equivalent to the shares in a scenario without climate policies and completely disconnected from national climate goals, these should be modified.

2.2. Analysis of Technical Aspects: Focus on Electricity Grids

Within the Special Issue, several papers examine the importance of electricity grid infrastructure within the energy system transition. Ritter et al. [12] therefore examine the effects on the cost of electricity generation and CO2 emissions resulting from a delayed expansion of interconnector capacities in a European high renewables electricity system by comparing different scenarios for the years 2030, 2040, and 2050. In a similar manner, Tafarte et al. [13] model the most efficient and fastest capacity expansion pathways of wind and solar photovoltaics in Germany considering aspects of electric energy storage and power grid expansions. Sanduleac et al. [14] simulate the effect of Solid State Transformers in a future energy system which play a crucial role to safely connect clusters of prosumers or low voltage networks with the bulk power system.

2.2.1. Effects of a Delayed Expansion of Interconnector Capacities in a High RES-E European Electricity System—Ritter et al. [12]

In order to achieve a high renewable share in the electricity system, a significant expansion of cross-border exchange capacities is planned. Historically, the actual expansion of interconnector capacities has significantly lagged behind the planned expansion. This study examines the impact that such continued delays would have when compared to a strong interconnector expansion in an ambitious energy transition scenario. For this purpose, scenarios for the years 2030, 2040, and 2050 are examined using the electricity market model PowerFlex EU. The analysis reveals that both CO2 emissions and variable costs of electricity generation increase if interconnector expansion is delayed. This effect is most significant in the scenario year 2050, where lower connectivity leads roughly to a doubling of both CO2 emissions and variable costs of electricity generation. This increase results from a lower level of European electricity trading, a curtailment of electricity from a renewable energy source (RES-E), and a corresponding higher level of conventional electricity generation. Most notably, in Southern and Central Europe, less interconnection leads to higher use of natural gas power plants since less renewable electricity from Northern Europe can be integrated into the European grid.

2.2.2. Capacity Expansion Pathways for a Wind and Solar Based Power Supply and the Impact of Advanced Technology: A Case Study for Germany—Tafarte et al. [13]

Wind and solar photovoltaics (solar PV) have become the lowest-cost renewable alternatives and are expected to dominate the power supply matrix in many countries worldwide. However, wind and solar are inherently variable renewable energy sources (vRES) and their characteristics pose new challenges for power systems and for the transition to a renewable energy-based power supply. Using new options for the integration of high shares of vRES is therefore crucial. In order to assess these options, the authors model the expansion pathways of wind power and solar PV capacities and their impact on the renewable share in a case study for Germany. Therefore, a numerical optimization approach is applied on temporally resolved generation and consumption time series data to identify the most efficient and fastest capacity expansion pathways. In addition to conventional layouts of wind and solar PV, the model includes advanced, system-friendly technology layouts in combination with electric energy storage from existing pumped hydro storage as promising integration options. The results provide policy makers with useful insights for technology-specific capacity expansion as the authors identified potentials to reduce costs and infrastructural requirements in the form of power grids and electric energy storage, and to accelerate the transition to a fully renewable power sector.

2.2.3. Resilient and Immune by Design Microgrids Using Solid State Transformers—Sanduleac et al. [14]

Solid State Transformers (SST) may soon become key technological enablers for decentralized energy systems. This work proposes a paradigm change in the hierarchically and distributed operated power systems where SSTs are used to asynchronously connect small low voltage (LV) distribution networks, such as clusters of prosumers or LV microgrids, to the bulk power system. The need for asynchronously coupled microgrids requires a design that allows the LV system to operate independently from the bulk grid and to rely on its own control systems. The aim is to achieve immune and resilient by design configurations that allow maximizing the integration of Local Renewable Energy Resources (L-RES). The paper simulates the way in which SST-interconnected microgrids can become immune to disturbances occurring in the bulk power system and how sudden changes in the microgrid can damp out at the Point of Common Coupling (PCC), thus achieving better reliability and predictability and enabling strong and healthy distributed energy storage systems (DESSs). Moreover, it is shown that in a fully inverter-based microgrid there is no need for mechanical or synthetic inertia to stabilize the microgrid during power unbalances. This happens because the electrostatic energy stored in the capacitors connected behind the SST inverter can be used for a brief time interval, until automation is activated to address the power unbalance for a longer term.

2.3. Analysis of Transport Sector

Two papers within this Special Issue take a closer look at the evolvement of the transport sector. Khalili et al. [15] examine the expected transportation demand and impact of alternative transportation technologies along with new sustainable energy sources on energy demand and emissions in the transport sector until 2050. Another paper by Child et al. [16] analyses the impact of high participation in vehicle-to-grid (V2G) in a 100% renewable Energy system on the island Åland in 2030 and the roles of various energy storage solutions

2.3.1. Global Transportation Demand Development with Impacts on the Energy Demand and Greenhouse Gas Emissions in a Climate-Constrained World—Khalili et al. [15]

This paper examines the expected transportation demand and impact of alternative transportation technologies along with new sustainable energy sources on energy demand and emissions in the transport sector until 2050. Battery-electric and fuel-cell electric vehicles are the most promising technologies. Electric ships and airplanes for shorter distances and hydrogen-based synthetic fuels for longer distances may appear around 2030 to reduce emissions from marine and aviation transport modes. The railway remains the least energy-demanding among the transport modes. An ambitious scenario for achieving zero greenhouse gas emissions by 2050 is applied, demonstrating the high relevance of direct and indirect electrification of the transport sector. Fossil-fuel demand can be reduced to zero by 2050; however, the electricity demand will to rise from 125 TWhel in 2015 to about 51,610 TWhel in 2050, substantially driven by indirect electricity demand of synthetic fuels. While the transportation demand roughly triples from 2015 to 2050, substantial efficiency gains enable an almost stable final energy demand for the transport sector, as a consequence of broad electrification. The overall well-to-wheel efficiency in the transport sector increases from 26% in 2015 to 39% in 2050. Power-to-fuels needed mainly for marine and aviation transport is not a significant burden for overall transport sector efficiency.

2.3.2. The Impacts of High V2G Participation in a 100% Renewable Åland Energy System—Child et al. [16]

A 100% renewable energy (RE) scenario featuring high participation in vehicle-to-grid (V2G) services was developed for the Åland islands for 2030 using the EnergyPLAN modelling tool. Hourly data was analyzed to determine the roles of various energy storage solutions, notably V2G connections that extended into electric boat batteries. Two weeks of interest (max/min RE) generation were studied in detail to determine the roles of energy storage solutions. Participation in V2G connections facilitated high shares of variable RE on a daily and weekly basis. In a Sustainable Mobility scenario, high participation in V2G (2,750 MWhel) resulted in less gas storage (1,200 MWhth), electrolyzer capacity (6.1 MWel), methanation capacity (3.9 MWhgas), and offshore wind power capacity (55 MWel) than other scenarios that featured lower V2G participation. Consequently, total annualized costs were lower (225 M/a). The influence of V2G connections on seasonal storage is an interesting result for a relatively cold, northern geographic area. A key point is that stored electricity need not only be considered as storage for future use by the grid, but V2G batteries can provide a buffer between generation of intermittent RE and its end-use. Direct consumption of intermittent RE further reduces the need for storage and generation capacities.

2.4. Analysis of Pricing, Storage, and Digitalization

Additional aspects of pricing, storage and digitalization are examined in the remaining three papers of the Special Issue. Maqbool et al. [17] provide an agent-based model of a hypothetical standalone electricity network to identify how the feed-in tariffs and the installed capacity of wind power, calculated in percentage of total system demand, affect the electricity consumption from renewables. In a paper by Cuculic et al. [18], a dynamic simulation model of a ship electrical power system is used to explore the suitability of large-scale energy storage for blackout prevention and to assess the possibility of an implementation of existing storage technologies in the maritime transportation sector. Ferreira and Martins [19] examine the integration of the "Internet of Things" (for the accounting of energy flows) and blockchain approach (to overcome the need for a central control entity) on energy markets and how these can create new open markets and revenues for stakeholders.

2.4.1. Assessing Financial and Flexibility Incentives for Integrating Wind Energy in the Grid Via Agent-Based Modeling—Maqbool et al. [17]

This article provides an agent-based model of a hypothetical standalone electricity network to identify how the feed-in tariffs and the installed capacity of wind power, calculated in percentage of total system demand, affect the electricity consumption from renewables. It includes the mechanism of electricity pricing on the Day Ahead Market (DAM) and the Imbalance Market (IM). The extra production volumes of Electricity from Renewable Energy Sources (RES-E) and the flexibility of electrical consumption of industries is provided as reserves on the IM. Five thousand simulations were run by using the agent-based model to gather data that were then fit in linear regression models. This helped to quantify the effect of feed-in tariffs and installed capacity of wind power on the consumption from renewable energy and market prices. The study concludes that the effect of increasing installed capacity of wind power is more significant on increasing consumption of renewable energy and decreasing the DAM and IM prices than the effect of feed-in tariffs. However, the effect of increasing values of both factors on the profit of RES-E producers with storage facilities is not positive, pointing to the need for customized rules and incentives to encourage their market participation and investment in storage facilities.

2.4.2. Analysis of Energy Storage Implementation on Dynamically Positioned Vessels—Cuculić et al. [18]

Blackout prevention on dynamically positioned vessels during closed bus bar operation, which allows more efficient and eco-friendly operation of main diesel generators, is the subject of numerous studies. Developed solutions rely mostly on the ability of propulsion frequency converters to limit the power flow from the grid to propulsion motors almost instantly, which reduces available torque until the power system is fully restored after failure. In this paper, a different approach is presented where large-scale energy storage is used to take part of the load during the time interval from failure of one of the generators until the synchronization and loading of a stand-by generator. In order to analyze power system behavior during the worst-case fault scenario and peak power situations, and to determine the required parameters of the energy storage system, a dynamic simulation model of a ship electrical power system is used. It is concluded that implementation of large-scale energy storage can increase the stability and reliability of a vessel's electrical power system without the need for the reduction of propulsion power during a fault. Based on parameters obtained from simulations, existing energy storage systems were evaluated, and the possibility of their implementation in the maritime transportation sector was considered. Finally, an evaluation model of energy storage implementation cost-effectiveness was presented.

2.4.3. Building a Community of Users for Open Market Energy—Ferreira et al. [19]

Energy markets are based on energy transactions with a central control entity, where the players are companies. In this research work, the authors propose an IoT (Internet of Things) system for the accounting of energy flows, as well as a blockchain approach to overcome the need for a central control entity. This allows for the creation of local energy markets to handle distributed energy transactions without needing central control. In parallel, the system aggregates users into communities with target goals and creates new markets for players. These two approaches (blockchain and IoT) are brought together using a gamification approach, allowing for the creation and maintenance of a community for electricity market participation based on pre-defined goals. This community approach increases the number of market players and creates the possibility of traditional end users earning money through small coordinated efforts. They apply this approach to the aggregation of batteries from electrical vehicles so that they become a player in the spinning reserve market. It is also possible to apply this approach to local demand flexibility, associated with the demand response (DR) concept. DR is aggregated to allow greater flexibility in the regulation market based on an OpenADR approach that allows the turning on and off of predefined equipment to handle local microgeneration.

3. Need for Further Research

The body of 100% renewable energy research is growing fastly for the various aspects, in particular for specific technical solutions, sector coupling insights and regions not yet researched much. Due continued demand for respective research a new Special Issue for 100% renewable energy insights is initiated. The scope is widened and also would like to attract papers covering

- Macroeconomic analyses of 100% renewable pathways;
- (Positive) side effects of 100% renewable pathways on other emissions and therefore health or, water-related aspects and other SDGs;
- Interdisciplinary approaches;
- Linkages of various models;
- Case studies for under researched areas around the world.

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Article

Sectoral Interactions as Carbon Dioxide Emissions Approach Zero in a Highly-Renewable European Energy System

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Abstract: Measures to reduce carbon dioxide emissions are often considered separately, in terms of electricity, heating, transport, and industry. This can lead to the measures being prioritised in the wrong sectors, and neglects interactions between the sectors. In addition, studies often focus on specific greenhouse gas reduction targets, despite the uncertainty regarding what targets are desirable and when. In this paper, these issues are examined for the period after 2030 in an existing openly-available, hourly-resolved, per-country, and highly-renewable model of the European energy system, PyPSA-Eur-Sec-30, that includes electricity, land transport, and space and water heating. A parameter sweep of different reduction targets for direct carbon dioxide emissions is performed, ranging from no target down to zero direct emissions. The composition of system investments, the interactions between the energy sectors, shadow prices, and the market values of the system components are analysed as the carbon dioxide limit changes. Electricity and land transport are defossilised first, while the reduction of emissions in space and water heating is delayed by the expense of new components and the difficulty of supplying heat during cold spells with low wind and solar power generation. For deep carbon dioxide reduction, power-to-gas changes the system dynamics by reducing curtailment and increasing the market values of wind and solar power. Using this model setup, cost projections for 2030, and optimal cross-border transmission, the costs of a zero-direct-emission system in these sectors are marginally cheaper than today's system, even before the health and environmental benefits are taken into account.

Keywords: energy system optimisation; carbon dioxide reduction; renewable energy; sector-coupling; open energy modelling; market value

1. Introduction

Many studies have focused on the reduction of carbon dioxide emissions in the electricity sector. Typically, the studies that restrict to renewable energy sources examine the flexibility requirements for high levels of variable renewable energy (VRE) generation, with flexibility options that include dispatchable renewables, storage, demand-side management, and grid expansion [1–6] (see [7] for a survey of studies with very high penetrations of VRE). The integration of VRE can be analysed using proxy metrics, such as the levels of curtailment, the market value of individual generation technologies [8], and other price statistics. However, focusing on electricity also means neglecting greenhouse gas emissions from other demand sectors, such as heating, transport, and industry, as well as ignoring sources of flexibility from, for example, delayed charging of electric vehicles, power-to-gas, or thermal energy storage. Such flexibility options could help to integrate renewables and mitigate the decline in market value of VRE as their penetration increases, which has been observed in several studies [9].

Many other studies have included other energy demand sectors, such as heating, transport, and non-electric industrial demand, but typically only consider a single region, thus neglecting cross-border energy trading, or do not consider the effects of sector coupling on market dynamics. Examples of single-region studies include studies for Germany [10–13], Denmark [14–16], Ireland [17,18], and the whole of Europe [19]. Other studies include multiple regions in Europe and the transmission networks between them [20–26], but then reduce the time resolution below the level required to assess the variability and flexibility requirements for high shares of wind and solar power [27,28]. Furthermore, the usual approach of reducing time resolution using typical representative days makes it impossible to represent multi-day extreme events and long-term energy storage properly. In [29], a multi-region, multi-sector European energy model was studied, on an hourly basis, for a full year. It was found that transmission helps to reduce the system costs in all scenarios, but the tighter the energy sectors are coupled, the smaller the benefit. Multi-day winter wind lulls with high heat demand were shown to be critical to driving up costs, but high costs could also be mitigated by power-to-gas and long-term thermal energy storage technologies.

Many studies have focused on specific carbon dioxide reduction targets for given periods, or have studied investment dynamically over multiple decades. Given the path uncertainty about exactly which target is necessary for a given period to reach a given temperature target [30], or about what is politically possible, very few studies have considered a broad range of possible targets for a given period. Other studies look at varying VRE penetration [5,9], where a carbon dioxide reduction target would better represent the desired end-goal of global warming mitigation.

From a policy perspective, the European Union (EU) has a variety of reduction targets for the time span 2030– 2050. By 2030, the EU aims to reduce domestic greenhouse gas (GHG) emissions by 40%, compared to 1990 [31], which is the same target as submitted as its Intended Nationally Determined Contribution (INDC) for the Paris Agreement [32]. For 2050, there is a wider span: A target of GHG reduction by between 80% and 95%, compared to 1990, was called for by the European Council in 2009 [33] and endorsed by the Commission [31], while the European Commission's 2018 'Long-Term Strategy for a Clean Planet' calculated additional scenarios for net-zero emissions in 2050 [34]. The fact that these targets encompass all sectors of the economy reinforces the necessity to model all energy sectors in low-emission scenarios. Of the 4.3 gigatonnes of CO_2-equivalent GHG emissions in the EU in 2016 (excluding land use, land-use change, and forestry), public electricity and heat production made up only 24%, while land transport comprised 21%, residential and services heating amounted to 13%, with the rest coming from process heat and process emissions in industry (21%), agriculture (10%), shipping (4%), aviation (4%), and waste management (3%) [35].

In this study, we address the deficiencies in the literature identified above by considering an existing European energy model, PyPSA-Eur-Sec-30 [29], that includes current electricity demand, land transport, and space and water heating at an hourly time resolution and with one node per European country, connected by cross-border transmission. We go beyond the standard approach in the literature and beyond the single target studied in [29] (95% CO_2 reduction), by examining the effects of a broad range of possible targets for direct carbon dioxide emissions for the period after 2030, which represents the period by which emissions in these sectors should reach zero, in order to keep warming below 1.5 °C above industrial levels [30,36]. By focusing on a specific period, our approach allows us to include every hour of a representative weather year and focus on the interactions between the sectors, variability, market prices, curtailment, and market values for different levels of carbon dioxide reduction. Previous works have often focused either on the electricity sector only, or have used typical days for their analysis, which hides the impact of extreme events and the full cost-benefit of long-term storage. As will be shown here, long-term storage has a strong effect on system costs and market metrics, so it is crucial to model it in sufficient temporal detail.

2. Methods

For this study we use the open model PyPSA-Eur-Sec-30, which covers the electricity, low-temperature heating, and land transport demand in Europe, with one node per country and an hourly time resolution for a historical year of demand and weather data. A full description of PyPSA-Eur-Sec-30 can be found in [29]; here, we restrict ourselves to describing the details necessary for the present study.

PyPSA-Eur-Sec-30 is a linear optimisation model which minimises the total investment and operational costs subject to technical constraints, the most important of which are: Meeting energy demand, respecting the weather dependence of a renewable energy supply, respecting the constraints on plant and grid capacity, and meeting carbon dioxide emission reduction targets. The objective function

$$\min_{\substack{G_{n,s},F_\ell,\\ g_{n,s,t},f_{\ell,t}}} \left[\sum_{n,s} c_{n,s} G_{n,s} + \sum_{n,s,t} o_{n,s,t} g_{n,s,t} + \sum_{\ell} c_\ell F_\ell \right]$$

runs over all nodes n, times t, and technologies s; summing generation and storage capacities $G_{n,s}$ and investment costs $c_{n,s}$, generation and storage dispatch $g_{n,s,t}$ and variable costs $o_{n,s,t}$, and, finally, the capacities F_ℓ of transmission lines and energy converters ℓ between buses, their flows at each hour $f_{\ell,t}$ and their capital costs c_ℓ.

The most important technology investments available to the model are listed in Table 1, along with cost projections for 2030; a full list of technologies, costs, and other technical parameters (such as efficiencies), along with references, can be found in [29]. All costs are in 2010 euros €$_{2010}$. Finally, 2030 was chosen for the cost projections, to remain on the conservative side of the time period under consideration (after 2030).

Table 1. Technology assumptions projected for 2030 (FOM is Fixed Operation and Maintenance costs, given as a percentage of the overnight cost).

Quantity	Overnight Cost [€$_{2010}$]	Unit	FOM [%/a]	Lifetime [a]
Wind onshore	1182	kW_{el}	3	25
Wind offshore	2506	kW_{el}	3	25
Solar PV rooftop	725	kW_{el}	3	25
Solar PV utility	425	kW_{el}	3	25
Battery power	310	kW_{el}	3	20
Battery energy	144.6	kWh	0	15
H_2 electrolysis	350	kW_{el}	4	18
H_2 fuel cell	339	kW_{el}	3	20
H_2 steel tank storage	8.4	kWh_{H_2}	0	20
Methanation	1000	kW_{H_2}	2.5	25
Ground-sourced HP	1400	kW_{th}	3.5	20
Air-sourced HP	1050	kW_{th}	3.5	20
Large CHP	600	kW_{th}	3	25
Large hot water tank	30	m^3	1	40
Transmission line	400	MWkm	2	40
HVDC converter pair	150	kW	2	40

Each country is linked to the others by expandable cross-border electricity grid capacity (see Figure 1 for the topology), and can also convert energy between sectors, as shown in Figure 2. The available electricity generation technologies are: Solar photovoltaic (PV), onshore and offshore wind, hydroelectricity, and open-cycle gas turbines (OCGT). Heat supply is split into high-heat-density areas with district heating (60% of urban areas, following [37]) and the remaining low-heat-density areas with decentralised individual heating units. In both areas, heat can be provided by gas boilers, heat pumps (HP), resistive heaters, and solar thermal collectors; in urban areas, large combined heat and power (CHP) plants are also available. Electricity can be stored in batteries, or water can be electrolysed to hydrogen, and/or then converted to methane. Heat can be stored in small short-term water tanks in rural areas, or large long-term water tanks in district heating networks. All road and rail transport is assumed to be electrified, since both the running costs and projected vehicle costs are assumed to be lower than fossil-fuelled vehicles with combustion engines by 2030 [38]. The capital costs of the vehicles are not included in the model. Passenger vehicles are represented by battery electric vehicles (BEV), 50% of which participate in demand-side management and can feed back into the grid, depending on market prices. Each participating vehicle makes 50 kWh available to the grid; the state of charge must return to at least 75% capacity each morning, for consumer convenience. The model can build new capacities of all energy infrastructure assets, with the exception of hydroelectric generators, for which existing capacities are assumed.

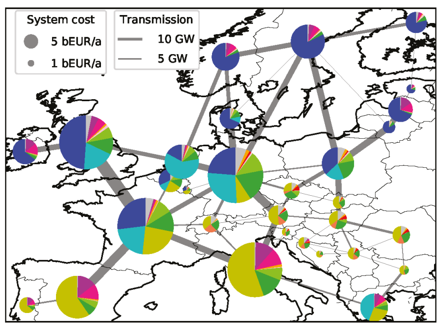

Figure 1. Costs by country with zero CO_2 emissions and optimal transmission. The colour assignments follow Figure 3.

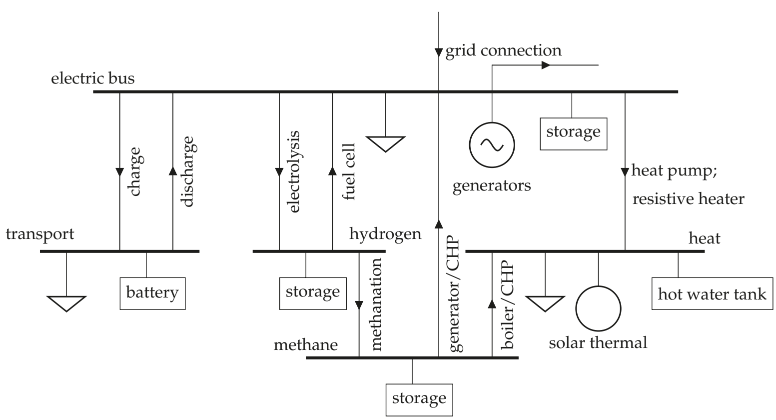

Figure 2. Energy flow at a single node. In this model, a node represents a whole European country. Within each node, there is a bus (thick horizontal line) for each energy carrier (electric, transport, heat, hydrogen, and methane), to which different loads (triangles), energy sources (circles), storage units (rectangles), and converters (lines connecting buses) are attached. The lines with arrows show the direction of energy transfer (Source: [29]).

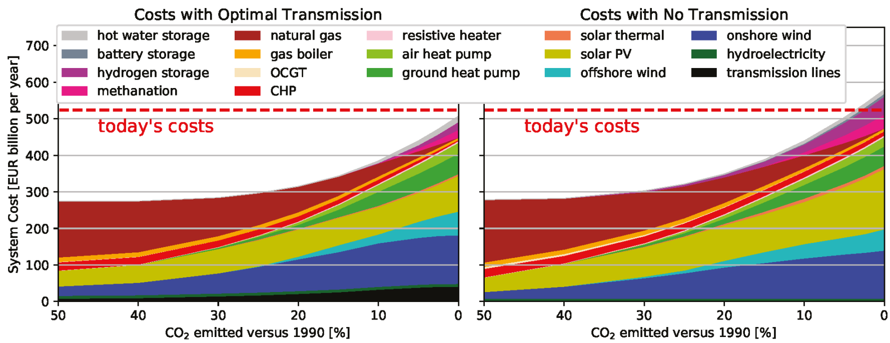

Figure 3. System costs for electricity, land transport, and space and water heating in Europe with a changing CO_2 limit, assuming the 2030 cost projections from Table 1. Left is the case with cost-optimal transmission, right is with no transmission. Estimated costs for today's system are marked with a red dashed line.

The inelastic energy demand $d_{n,t}$ at each bus n must be met at each time t by either local generators and storage $g_{n,s,t}$ or by the flow $f_{\ell,t}$ from a connector ℓ

$$\sum_s g_{n,s,t} + \sum_\ell \alpha_{\ell,n,t} \cdot f_{\ell,t} = d_{n,t} \qquad \leftrightarrow \qquad \lambda_{n,t} \;\; \forall n, t, \tag{1}$$

where $\alpha_{\ell,n,t} = -1$ if ℓ starts at n, and $\alpha_{\ell,n,t} = \eta_{\ell,t}$ if ℓ ends at n, and $\eta_{\ell,t}$ is a factor for the efficiency of the energy conversion in ℓ; it can be time-dependent—for example, depending on the outside temperature, like for a heat pump. The Karush-Kuhn-Tucker (KKT) multiplier $\lambda_{n,t}$ represents the market price of the energy carrier.

Direct CO_2 emissions are limited by a cap, CAP_{CO_2}, which is set relative to the total emissions from electricity, heating, and land transport in 1990 (3016 megatonnes of CO_2 [39]). Only CO_2 emissions are considered, because other greenhouse gas emissions in these sectors comprised less than 2% of the CO_2-equivalent emissions in these sectors in 1990. The cap is implemented using the specific emissions ε_s, in CO_2-tonne-per-MWh_{th}, of the fuel s, the efficiency $\eta_{n,s}$, and the dispatch $g_{n,s,t}$ for generators, as well as the difference in energy level $e_{n,s,t}$ for non-cyclic storage (relevant for methane, which is depleted during the year):

$$\sum_{n,s,t} \varepsilon_s \frac{g_{n,s,t}}{\eta_{n,s}} + \sum_{n,s} \varepsilon_s \left(e_{n,s,t=0} - e_{n,s,t=T}\right) \leq \text{CAP}_{CO_2} \;\; \leftrightarrow \;\; \mu_{CO_2}. \tag{2}$$

The KKT multiplier μ_{CO_2} indicates the CO_2 price necessary to obtain this reduction in the model without the constraint.

In this study, the CO_2 limit is varied to represent different possible reduction targets. This could also be interpreted as different CO_2 targets on the path down to zero emissions, over time, but note that, here, the cost assumptions remain fixed for the different targets, and previous investment decisions are not considered (except for existing hydroelectric generators).

To focus on low-emission technologies and avoid additional computational complexity, the only fossil fuel available in the model is natural gas, whose cost and emissions factors are 21.6 €/MWh_{th} and 0.19 $tCO_2/\text{MWh}_{\text{th}}$ respectively.

The model was implemented in the open energy modelling framework 'Python for Power System Analysis' (PyPSA) [40]. The code and data for the model is freely available online [41,42].

3. Results

3.1. Total System Costs

In Figure 3, the composition of the total system costs, including transmission, generation, and storage, is shown as the CO_2 limit is made successively stricter, with cost-optimal cross-border transmission (left) and no cross-border transmission (right). The case of no cross-border transmission is provided as a reference point for the many single-country studies in the literature [10–18] that do not consider cross-border transfers, and to quantify the full benefit of interconnection. Interconnection was shown, in many studies, to help to balance variable renewable energy sources, particularly wind, and to reduce the costs of carbon dioxide mitigation [2,4,6,43–51].

In both systems, the CO_2 constraint is non-binding, down to 50% of the 1990 emissions. In other words, the greenfield cost optima with no CO_2 constraint or pricing already result in a large CO_2 reduction, largely due to new installations of CHPs fired by natural gas and around a 50% share of renewables in the electricity supply. If there were other cheaper, but more CO_2 intensive, generators in the model, such as coal, this minimum would be at a higher level of CO_2 emissions. For comparison, the 2016 emissions in the energy sectors considered here were 14.2% below their 1990 level.

The cost of today's system is estimated to be 524 billion euros per year, making the greenfield, unconstrained cost-optimum 48% cheaper than the current system. Today's costs are hard to gauge precisely, because of legacy investments over decades, but for this estimate we have assumed an average cost of electricity generation (including investment) of 70 €/MWh_{el}, 8 €/MWh_{th} for solid fuels, 47 €/MWh_{th} for oil, and 22 €/ MWh_{th} for gas, and assume that the entire non-electric heat load is met by fossil fuel boilers priced like gas boilers, which are dimensioned to meet the peak thermal load in each country. With these assumptions and energy consumption figures from the Eurostat energy balances for 2011 [52], the costs are 221 billion €/a for electricity generation (this agrees with the estimate based on price tariff statistics in [7], which excludes network costs and taxes), 3 billion €/a for cross-border transmission, 167 billion €/a for land transport fuels, 98 billion €/a for heating fuels, and 35 billion €/a for the boilers; resulting in a grand total of 524 billion €/a.

As the CO_2 limit is reduced below 50% and down to zero, costs rise by 108% with no transmission, and by 85% with optimal transmission. With zero direct CO_2 emissions and optimal transmission, system costs are 3% below today's costs, for the 2030 cost projections used here. Higher costs at lower emissions are driven by the need to defossilise heating, which is supplied by a combination of heat pumps and synthetic methane to bridge multi-day periods with low wind and solar energy. Bioenergy could also be used to bridge these periods and, thus, lower costs. However, as we discuss in Section 4, there is uncertainty regarding the sustainability of its widespread use and also strong competition from aviation, shipping, production of plastics, and other non-electric industrial demand for limited sustainable bioenergy resources.

The cost rise is more pronounced with no transmission, since variable renewables cannot be balanced between countries, but must be balanced for each country, in a self-sufficient manner, by using storage. In the case of optimal transmission, despite the extra costs of the transmission infrastructure, the costs of the total zero-CO_2 system are 13% lower than the no-transmission case. The optimal amount of transmission grows by a factor of 5 as the CO_2 limit is reduced, reflecting how the benefit of transmission increases as more variable renewables enter the electricity system. Transmission helps to balance the variability of renewables over space, particularly for wind, because wind has a synoptic-scale correlation length of 400–600 km [53], which is smaller than the size of the continent. At zero direct carbon dioxide emissions, the total volume of cross-border transmission (the sum of length times capacity for each line, where the length is the distance between the country centres) is 382 TWkm, which is over 12 times today's volume of 31 TWkm. Given the current public acceptance issues for overhead transmission, some of these transmission projects would have to be traded against the slightly higher costs of scenarios with less cross-border transmission.

For the rest of this article, we focus on the results from the case with optimal transmission.

From the map of investments, in Figure 1, it can be seen that the optimal transmission network is particularly strong between northern countries, where it can balance their plentiful wind resources. Power-to-gas investment is strongest in the peripheral countries, where it is not cost-optimal to build cross-border grid capacity to absorb all excess renewable generation. In central countries, such as Germany, there is so much grid capacity that power-to-gas is not cost effective, at least for the 2030 cost projections used here.

In Figure 4, the total cost behaviour is reflected in the shadow price μ_{CO_2} of the CO_2 constraint (Equation (2)) as the CO_2 limit is tightened. The CO_2 price rises from zero at the non-binding 50% CO_2 reduction, to around 500 €/tCO_2 once all CO_2 is eliminated from the model. As pointed out in [29], this high price is a direct reflection of the difference between the cost of natural gas (21.6 €/MWh_{th}) and the high price of synthetic methane in the model (113.7 €/MWh_{th}), which is needed for low-fossil heating. It is significantly higher than the January 2019 price of 20–25 €/tCO_2 in the European Emissions Trading System (ETS), which covers power generation, some industrial sectors, and aviation, amounting to around half of all European CO_2 emissions. The price is so high that it may be more cost-effective to eliminate CO_2 in the other sectors not covered in the model, such as aviation, shipping, industry, or, indeed, by capture directly from the air.

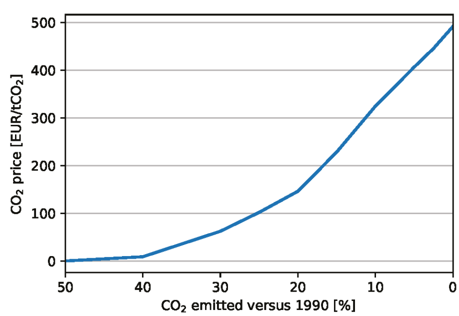

Figure 4. CO_2 shadow price in the model as CO_2 emissions are restricted in the case of cost-optimal cross-border transmission.

3.2. Defossilisation of Sectors

Next, we examine how the different sectors are defossilised. Because the model includes only the transport fuel costs and not the capital costs of vehicles, transport is electrified immediately as the electricity consumed for each kilometre travelled is less costly than petrol or diesel. The fossil-share for transport, then, reflects the fossil-share in electricity. The projected capital costs for electric vehicles in 2030 are comparable or lower than those for internal combustion engine vehicles [38], so the inclusion of these costs would not alter the early electrification of transport. Turning to electricity and heating, the picture is more complicated, as can be seen from the fossil fuel shares in Figure 5, the electricity supply in Figure 6, and the water and space heating supply in Figure 7. Electricity and electrified transport are defossilised swiftly, whereas heating only begins to be defossilised in earnest below 30% total CO_2 emissions, with the majority of the reduction coming at the end below 20%. This can also be seen in the total investments in Figure 3.

The electricity supply in Figure 6 sees a rapid increase in wind and solar installations, with the remaining electricity demand being supplied by existing hydroelectric plants and combined heat and power (CHP) stations. The renewable energy share increases (Figure 5) at the same time as total electricity demand increases (Figure 6). With zero net emissions, the total electricity demand is more than double the 2011 total of 3153 TWh_{el}/a. This increase is due to the electrification of transport and heating, as well as conversion losses in the power-to-gas and other storage units.

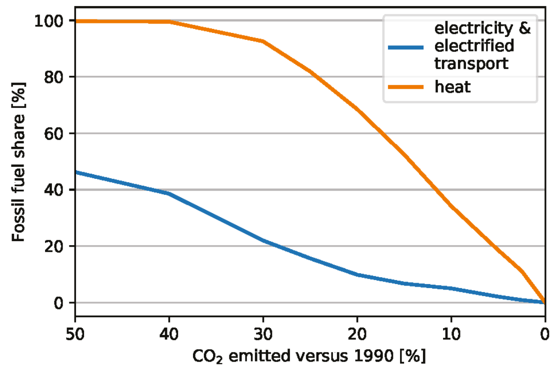

Figure 5. Share of fossil fuel energy provision in electricity, electrified transport, and heat.

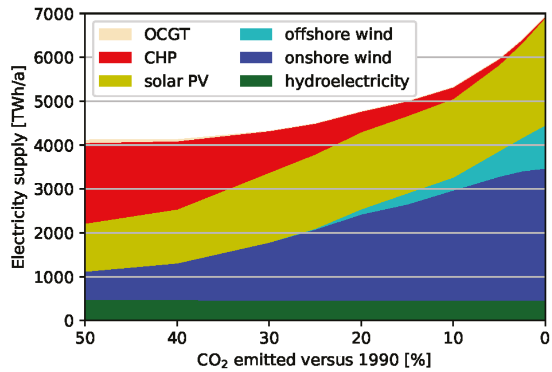

Figure 6. Breakdown of electricity supply by technology.

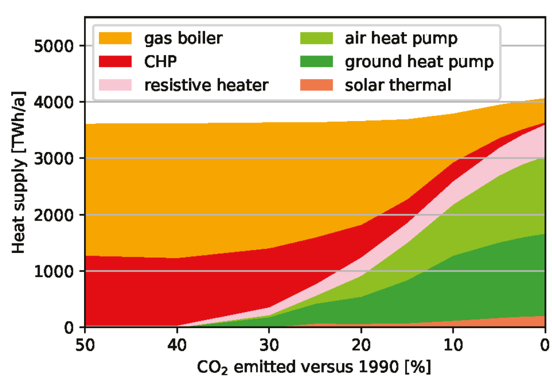

Figure 7. Breakdown of space and water heating supply by technology.

In the heating sector (Figure 7), when the CO_2 constraint is non-binding, heating is provided cheaply by natural gas in either gas boilers or CHPs. Heating is defossilised mostly by heat pumps, which drive up costs because, as well as the units themselves, they also require additional electricity generation capacity. Smaller contributions are made from resistive heaters and solar thermal collectors, while some gas boilers remain at the end to provide backup heat with synthetic methane. The overall heat demand rises slightly towards zero emissions, because of conversion losses in long-term thermal storage facilities in district heating networks.

It was identified, in [29], that one of the hardest aspects of the defossilisation of heating is the long winter cold spells with low generation from wind and solar, high heating demand, and lower heat pump coefficients of performance. Heating in these periods can be achieved by producing synthetic methane or by using long-term thermal energy storage, but particularly the former drives up system costs significantly. This effect can be seen in the rise of system costs, in Figure 3, as the last CO_2 is removed from the system using the power-to-gas facilities.

The expense of fully defossilising space and water heating was also confirmed in [54], which showed that cheap and abundant renewable energy is not sufficient to incentivise the full defossilisation of heating. CO_2 prices are also required to narrow the cost differential between gas and low-carbon options.

3.3. Metrics for VRE Integration

In this section, the curtailment, market prices, and market values of the different technologies are considered.

Power-to-gas is forced into the system primarily by the need for synthetic fuels in the heating sector during cold spells. However, its introduction has big effects on the operation of other system components and market behaviour. In Figure 8, the effect on curtailment is plotted. As CO_2 is reduced below 20%, curtailment initially rises, reaching a peak of 26% of offshore wind, 7% of onshore wind, and 3% of solar available energy, at a level of 10% CO_2. This reflects the strong seasonal peaking of the heating demand, which is hard to match with the output of solar and even with wind, which also peaks in the winter. Below 10% CO_2, it becomes cost-optimal to invest in power-to-gas. This means that any excess renewable energy can can be converted into synthetic fuels, removing almost all the curtailment when direct carbon dioxide emissions reach zero. Curtailment is worse for offshore wind than onshore or solar as, during times of excess, the dispatch rules were chosen so that offshore wind is curtailed first, then onshore wind, then solar. Offshore wind is not plotted above 25% carbon dioxide reduction, because its feed-in was negligible for these values.

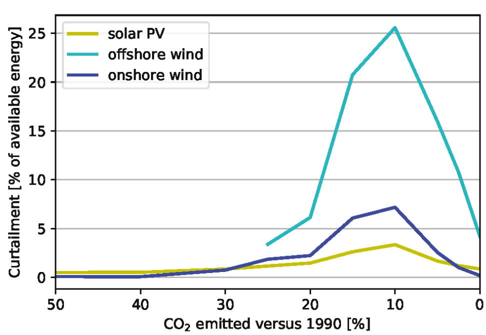

Figure 8. Curtailed variable renewable energy, as a percentage of the available energy.

A similar turning point can be seen in the electricity price statistics, plotted in Figure 9. For these statistics, all averages are weighted by the electric load, which includes electric vehicles, heat pumps, resistive heaters, and storage units in charging mode. The percentage of hours with zero marginal prices in the model drops from a peak of 31% of hours at 10% CO_2, to just 6.9% of hours at 0% CO_2. With power-to-gas, it becomes worthwhile to put renewables to economic use in almost every hour, and only in a small fraction of hours is there an excess of renewable energy. Figure 9 also shows rising market prices until 10% CO_2, reflecting the increase in total system costs, at which point the introduction of large flexible demand from electrolysers allows low-price hours to be better used. This drives down average prices since, here, the prices are weighted by the volume of the electrical load in each hour. The simple time-weighted average electricity price increases monotonically to 78 €/MWh$_{el}$ as emissions tend to zero. Prices for heating, hydrogen, and methane also increase monotonically. The rising standard deviation in the electricity prices reflects rising volatility from the increasing shares of variable wind and solar generation.

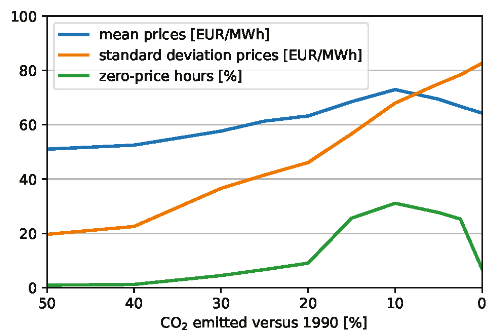

Figure 9. Load-weighted statistics of electricity prices.

The turning point is, again, reflected in the market values of the different technologies connected to the electricity system, as shown in Figure 10. Here, we define the market value as the average price of each unit of electricity consumed or produced by each technology, relative to the average load-weighted price; that is,

$$\mathrm{MV}_s = \frac{\sum_{n,t} \lambda_{n,t}\, g_{n,s,t}}{\sum_{n,t} g_{n,s,t}} \left(\frac{\sum_{n,t} \lambda_{n,t}\, d_{n,t}}{\sum_{n,t} d_{n,t}} \right)^{-1}, \tag{3}$$

where $\lambda_{n,t}$ is the locational marginal price from Equation (1), $g_{n,s,t}$ is the generator dispatch, and the demand $d_{n,t}$ includes electric vehicles, heat pumps, resistive heaters, and storage units in charging mode. In the language of [9], MV_s is the long-term value factor. The market value gives a useful indication of the value of each technology to the system.

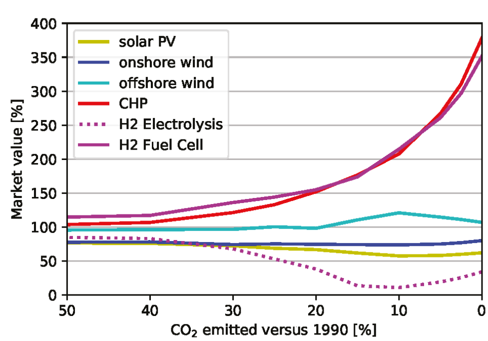

Figure 10. Market values relative to the average load-weighted price.

In general, it is expected, from other studies [8,9], that the market value of variable renewable generators, such as wind and solar, should reduce with higher penetration, as they decrease the market prices in exactly the hours when they produce at high volume, thanks to the merit order effect. Down to 10% CO_2, the relative market values do indeed diverge, with onshore wind and solar receiving low market values, while less-variable offshore wind reaches 121% market value and storage units achieve ever-stronger price arbitrage. However, below 10% CO_2, the market values of the variable generation technologies begin to converge to 100% again, as increased flexibility, in particular from power-to-gas, creates a market for wind and solar power. Below 10%, electrolysers pay increasingly higher prices for electricity as the demand for hydrogen increases, reaching an average price of 22 €/MWh_{el} paid for electricity by electrolysers at zero CO_2 emissions (this price is obtained by multiplying the value factor 34% from Figure 10 with the average price 64 €/MWh_{el} from Figure 9). This results in an average marginal price of hydrogen of 49 €/MWh_{th} (27.5 €/MWh_{th} for the electricity and the rest for investments in electrolysers and hydrogen storage).

It can be concluded that in a highly-integrated sector-coupled low-carbon system, the market values of wind and solar do not decline as precipitously as has been observed at lower renewable penetrations in electricity-only models [9]. Theoretically, this is inevitable: Given that all actors make back their costs from market prices in a long-term equilibrium (like this model), and that VRE make up the majority of the total system costs, VRE cost recovery constitutes a large share of the market prices.

The increasing interaction between electricity market prices and the production and consumption of synthetic gas is also strongly reflected in the time series; see Figure 11. The gas dispatch and electricity price are strongly correlated, with a Pearson correlation coefficient of 0.82 with zero CO_2 emissions. This correlation is stronger than the correlation of the prices with the residual load (−0.30) or variable renewable generation (−0.33). When renewables are abundant and other demand is low (particularly, in the summer), prices are low, and so a lot of synthetic gas is produced; the methanation units achieve an average of 4953 full load hours, thus enabling them to recover their high capital costs. When renewables are scarce and demand is high, particularly in the winter, gas is consumed in electricity and heating as a backup.

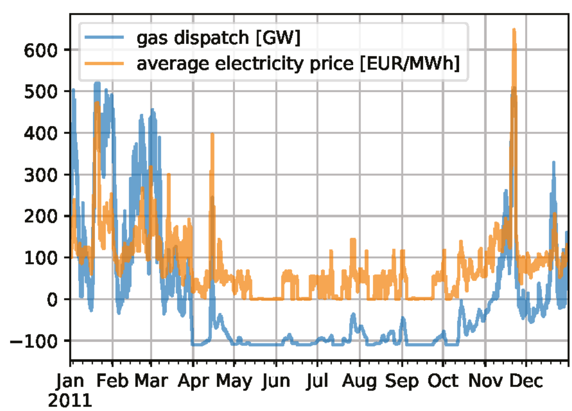

Figure 11. Zero CO_2 scenario: Methane dispatch (positive when synthetic methane is consumed, negative when produced by methanation) versus average electricity prices.

4. Limitations of this Study

An extensive discussion of the limitations of the model PyPSA-Eur-Sec-30 can be found in the paper that introduced the model [29], while a sensitivity analysis on many of the costs and other assumptions in the electricity sector was carried out in [55]. Here, aspects are highlighted that particularly impact the results discussed in this paper.

One of the primary limitations of this study is the exclusion of biomass as a technology option. Biomass was excluded, partly because of the large uncertainties surrounding the sustainability of its widespread use [56], and partly because there is likely to be intense competition for limited sustainable biomass potentials from the other hard-to-defossilise sectors that are not included in this model: Plastics production, other non-electric industrial demand, shipping, and aviation. Biomass could help to alleviate the cost peak in Figure 3, by reducing the need for synthetic gas. Biofuels could act as a bridge for existing internal combustion engine vehicles before electric vehicles become prevalent, although, in the long-term, their use should probably be restricted to hard-to-electrify sectors, such as aviation [57]. Bioenergy with carbon capture and sequestration (BECCS) may also play an important role in long-term mitigation scenarios by providing negative emissions, although there is some scepticism about the widespread use of this technology in integrated assessment models [58–61]. Given that sustainable biomass resources are limited [62], once the other sectors are included, the demand for synthetic fuels will remain high, so that the effects seen in this paper are likely to remain. This has been confirmed in an upcoming study by some of the authors.

Including the full industrial sector would also allow the model to consider the indirect emissions during production of energy infrastructure assets (only direct emissions have been included here).

Given the focus in this paper on a high share of renewables, which is also the policy goal of many EU member states, nuclear and fossil generation with carbon capture and sequestration (CCS) were not considered. The time-weighted mean electricity price with zero emission was 78 €/MWh_{el}, which is the price with which nuclear or fossil with CCS would have to compete. Recent nuclear projects in Europe have not been able to attain this price level. CCS may still be necessary in the future for the net negative emissions that are required in many scenarios that meet the Paris Agreement targets [32].

Other uncertainties concern the availability and costs of relatively new technologies, such as battery electric vehicles with vehicle-to-grid functionality and power-to-gas infrastructure; the sensitivity of the results to these assumptions was examined in [29,55] and found to be below 10%. As can be seen from their shares in the cost structure in Figure 3, the primary sensitivities are, in fact, to the costs of wind, solar, and heat pumps and, of course, to the discount rate. Even doubling the costs of power-to-gas infrastructure has only a limited effect on the total costs. The solar cost reductions for 2030 assumed here are ambitious, but are in line with recent cost declines. A full range of PV costs, going all the way down to zero, were examined in [55], and, although more PV investment is seen with lower costs, in Europe the PV penetration is limited by a generation pattern that is anti-correlated with the seasonal variations in demand. If the cost projections for electric vehicles used here prove to be too ambitious, this may delay the electrification of land transport.

Further modelling limitations include the restriction to a single representative historical year and the assumption of perfect foresight and of perfect markets; these limitations are driven by computational restrictions. Distribution grid reinforcement was not considered, since it does not represent a public acceptance problem, and because the costs of reinforcement are likely to be low compared to total system costs [7].

5. Conclusions

In this paper, we have studied the changes in energy system properties as the constraint on allowed direct CO_2 emissions is varied, in a sector-coupled model covering European electricity, heating, and land transport demand. A reduction in CO_2 emissions of 50%, compared to 1990 levels, for the considered low-carbon technologies is cost-effective, regardless of the level of transmission expansion, thanks to increasing shares of cheap wind and solar electricity and the electrification of land transport. Below this level, costs rise as carbon dioxide is initially pushed out of the system by heat pumps and, finally, by the synthetic fuels that are necessary to bridge long cold spells with low wind and sun. However, even with zero direct CO_2 emissions, the total system costs are comparable to the costs of today's energy system, when using cost projections for 2030.

The introduction of power-to-gas, driven by these cold spells when cheap low-emission electricity is scarce, alters market dynamics because of the ease of the long-term storage of gas. This results in fewer hours of zero prices, substantially less curtailment, and a re-convergence of the market values of variable renewable generators towards the average market price.

While some synthetic gas could be replaced by bioenergy in the model, either in the form of solid biomass or biogas upgraded to biomethane, it should also be borne in mind that scarce sustainable bioenergy resources will also be required in other sectors which are harder to electrify, such as aviation, shipping, plastics production, and other non-electric industrial demand. Exploring these trade-offs in a high resolution model is an interesting topic for future research.

While model limitations should be borne in mind, several relevant policy measures can be deduced from the results: Increasing low-emission technologies in electricity generation is a priority, particularly given that defossilisation strategies in other sectors rely on electrification; reducing emissions in space and water heating is more expensive and sees investment accelerate towards the end of the energy transition; CO_2 prices (or equivalent second-best measures, like mandates for district heating or heat pumps) will be required across all sectors and at levels much higher than seen today in the European Emissions Trading System; power-to-gas is an important part of guaranteeing system security during cold winter wind lulls, and so investment in research, development, and deployment should be increased to guarantee that power-to-gas can scale up in time; zero-emission systems can be cost-effective, even before accounting for the health and environmental benefits, so expense is not a limitation for the energy transition; it may be cost-effective to go further than the EU's current 40% greenhouse gas reduction target for 2030 and aim for zero net-emissions in 2050, pending further investigations of the integration of industrial, shipping, and aviation demand.

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Abbreviations

The following abbreviations are used in this manuscript:

a	annum (year)
BEV	Battery Electric Vehicle
CCS	Carbon Capture and Sequestration
CHP	Combined Heat and Power plant
CO_2	Carbon dioxide
ETS	Emissions Trading System
EU	European Union
FOM	Fixed Operation and Maintenance
GHG	Greenhouse Gas
H2	Hydrogen gas
HP	Heat Pump
HVDC	High Voltage Direct Current
INDC	Intended Nationally Determined Contribution for the Paris Agreement [32]
KKT	Karush-Kuhn-Tucker
MV	Market Value
OCGT	Open Cycle Gas Turbine
PV	Photovoltaic
PyPSA	Python for Power System Analysis
PyPSA-Eur-Sec-30	30-node sector-coupled PyPSA model for Europe
VRE	Variable Renewable Energy

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Pathways for Germany's Low-Carbon Energy Transformation Towards 2050

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Abstract: Like many other countries, Germany has defined goals to reduce its CO_2-emissions following the Paris Agreement of the 21st Conference of the Parties (COP). The first successes in decarbonizing the electricity sector were already achieved under the German Energiewende. However, further steps in this direction, also concerning the heat and transport sectors, have stalled. This paper describes three possible pathways for the transformation of the German energy system until 2050. The scenarios take into account current climate politics on a global, European, and German level and also include different demand projections, technological trends and resource prices. The model includes the sectors power, heat, and transportation and works on a Federal State level. For the analysis, the linear cost-optimizing Global Energy System Model (GENeSYS-MOD) is used to calculate the cost-efficient paths and technology mixes. We find that a reduction of CO_2 of more than 80% in the less ambitious scenario can be welfare enhancing compared to a scenario without any climate mitigating policies. Even higher decarbonization rates of 95% are feasible and needed to comply with international climate targets, yet related to high effort in transforming the subsector of process heat. The different pathways depicted in this paper render chances and risks of transforming the German energy system under various external influences.

Keywords: decarbonization; energy system modeling; GENeSYS-MOD; renewables; energy policy; energy transformation; Energiewende

1. Introduction

Human activities have already caused approximately 1.0 degree Celsius of global warming above pre-industrial levels by 2017 [1]. Based on the analysis conducted by the Intergovernmental Panel on Climate Change (IPCC) [1–4], the global carbon budget to limit the temperature rise to 1.5 °C will soon be exhausted. With an increasing global mean temperature, the risk of abrupt and major irreversible changes will grow and impact human life in many ways [1,5]. Therefore, the global community must undertake measures to find a collective climate policy towards decarbonization.

To get the world mobilized, all (then) 197 United Nations (UN) member countries agreed to the 2015 UN Climate Change Conference held in Paris [6,7]. Thereby, policymakers ratified their Nationally Determined Contributions (NDCs) in the so-called Paris Agreement. The are the nations self-defined emission reduction goals, aiming to keep the global mean temperature increase well below 2 °C and limit the share of carbon dioxide equivalents to less than 450 parts per million (ppm) within the atmosphere [7]. They are, however, not sufficient to reach the climate target.

Induced by the German Energiewende, there is a remarkable uptrend in using renewable energy sources in Germany: Since 2010, in the framework of the Energiewende a series of decisions where made to decarbonize and decentralize the German energy system and more general, find a concept of a future energy system [8]. Nevertheless, there are still doubts if an energy system based on 100% renewable energy is viable and achievable, both in technical, as well as economic terms, illustrated in the debate of Heard et al. [9] and Brown et al. [10]. A correlating attribute for realizing a renewable energy integration is the consideration of technology-specific storage aspects. However, there are still conflicting opinions on the necessity and size of electric storages in the power grid, as exemplified in the dispute between Sinn [11] and Schill et al. [12] (See also Section 1.3).

Thus, it is crucial to elaborate scenarios, driven by different storylines that target a rather holistic perception than solely absolute numbers [13]. To do so, this paper examines three different scenarios for Germany's low-carbon transformation concerning the ratified NDCs. To establish a differentiated impact assessment, those are implemented into the Global Energy System Model (GENeSYS-MOD) v2.0 [14,15]. This multi-sectoral energy system model is used to analyze national trajectories for the sectors electricity, heat, and transportation until 2050 by applying a cost-optimization algorithm. Based on its federal system, Germany is divided into 16 sub-regions to indicate bottlenecks and potentials for a sophisticated recommendation for action. Despite a limited transferability to other countries, a close consideration of the German case bears insights on its past and future development and might offer some lessons and best practices for other nations, because of Germany's fruitful start and the *Energiewende's* success in laying down a base for an decarbonized energy system [8], its close interdependence with other European nations and a certain maturity of the idea of renewable energy supply [8]. Section 1.1 gives a brief overview on the status quo of Germany's climate policy and energy system within its national and international context. Sections 2.1 and 2.2 introduce three different scenarios and their implementation in GENeSYS-MOD. The model results of the scenarios are displayed and discussed in the following Section 3 to provide holistic recommendations for political action. Section 4 concludes the paper.

1.1. German Climate Policy

Germany takes part in the United Nations Framework Convention on Climate Change (UNFCCC) since its foundation. The first Conference of the Parties (COP) took place in 1992 in Berlin, the capital of Germany. Since then, Germany took part in various multilateral agreements and programs for global climate protection, like the Montreal Protocol to protect the ozone layer [16] and the Kyoto Protocol [17]. As part of the European Union (EU), Germany commits itself to a number of further climate protection measures and targets. Since 2005, for example, emissions from the domestic energy industry and heavy industry have been covered by an Emissions Trading System (ETS). This accounts for 45% of European emissions [18]. A second approach to reducing greenhouse gas (GHG) emissions on a European level is pan-European reduction targets, which should include emissions outside the ETS. These targets are also included in the Paris Agreement and state that by 2020, greenhouse gas (GHG) emissions should be reduced by 10 percent compared to 2020 [19] and by 30 percent compared to 2030 [20]. In order to balance the burden between the countries according to their economic performance, the Effort Sharing scheme is implemented. Hence, relatively underdeveloped countries can even increase their emissions by a certain amount, while other countries have to reduce beyond the European target. Germany is to reduce its emissions by 14 percent by 2020 compared to 2005 [19] but will miss this European target [21]. Aside the European targets, Germany has set itself own targets for 2030 and 2050, based on the reference year of 1990. These targets are also subject to the Paris Agreement ratified by Germany. The main goal is to provide a reduction of GHG emissions of at least 55% until 2030 and 80–95% in 2050 compared to 1990-levels. Additionally, renewable energy sources are prescribed to account for at least 60% of the energy consumption in 2050, while efficiency rates should increase by 50% [22]. The final decision to phase out nuclear power by 2022 has already been cushioned by the addition of renewable energy plants. The annual nuclear power production fell from 170 Terawatt Hours (TWh) in 2000 to 76 TWh in 2018 while at the same time renewables rose from 38 TWh to 229 TWh. However, power production with coal decreased only from 291 TWh to 229 TWh in the respective timespan [23]. Hence, there is a large gap between the own decarbonization targets and the actual implementation so far. In 2018, the German government convened a commission “Growth, Structural Change, and Employment” (“Coal-Commission”) for the purpose of implementing practical measures to concretize the goals set out in the climate protection plan. In January 2019, their final report on the gradual reduction and cessation of coal-fired power generation was published [24]. This report suggests that by 2022, coal-fired power plant capacities have to be reduced gradually to around 15 Gigawatt (GW) of lignite and 15 GW of hard coal. Phasing out coal is recommended at the latest by 2038 [24]. In the second half of 2018, a new global movement gained medial presence: Every Friday, schoolchildren, supporters from universities, and the scientific community protest for a more decisive approach of politics in climate questions. The German branch of the “Fridays for Future” movement demands Germany shall have no net emissions of carbon dioxide (CO_2) by 2035 and complete phase-out of coal by 2030. Also, they demand an electricity supply that is entirely renewable by 2035. By the end of 2019, the movement further demands to shut down one-quarter of capacity of coal-fired power plants an end to all subsidies on fossil fuels and a pricing scheme for CO_2 that internalizes all external effects and thus they refer to the German Environment Agency which estimates a price of 180 € per ton of CO_2 [25].

Further insights on the regional differences, stakeholders in Germany, and the division of competences among the ministries can be found in the Appendix A.

1.2. Energy System

The German energy system is undergoing fundamental restructuring intending to achieve a renunciation of fossil fuels, a switch to renewable energies, and more efficient use of energy. The driving force behind this transformation is the man-made global climate change through the emission of GHG and the climate protection targets developed in response [26].

The current supply structure of the power, heating, and transport sectors, as well as the transmission grid and the final energy demand, serve as a starting point for modeling the future energy system of Germany.

Even though electricity generated by renewable technologies reached a share of approximately 37.8% in 2018, the four conventional sources coal (hard coal and lignite), oil, fossil gas, and nuclear are still dominating [23]. This translates to 313 million tons of CO_2 equivalents released in the atmosphere in the year 2017 [27]. Lignite and hard coal account for the highest share (35.4%) of electricity produced in Germany in 2018. Gas fired power plants are held as a flexible reserve to cushion the renewables’ volatility and grid compensatory measures. Most of the renewable power generation comes from wind and solar with wind energy already providing 17.2% of the total electricity production [23]. With the further development of offshore capacities in the Baltic- and North Sea, as well as onshore wind turbines focused in northern Germany, this share will increase. Among more cost-intensive technical requirements [28], the maximum potential for offshore installations of 85 GW [29] is lower compared to the potential of onshore installations, which is set at 200 GW [30]. Photovoltaics (PV) are another important pillar of Germany’s future electricity supply, contributing about 7% of the electricity supply today [23]. Braun et al. [31] calculated a potential for open-field PV of 297 GW following the target set in German Renewable Green Energy Act (EEG) 2017 of locating open-field PV plants along traffic routes [32]. Storing the generated electrical energy will become a challenge concerning the volatility of the feed-in of power into the grid by solar and wind plants. Storage technologies, such as batteries, pumped hydro power plants, or gas- and heat storages can be used to effectively reduce the fluctuating power feed in by renewables. CCS technology will not play a role in the German nor

European power sector in the future. It has turned out that the implementation is technologically too demanding, very expensive and not needed [33–35].

Compared to the power sector, the heating sector faces more difficulties to become renewable. In fact, the transition of the heating sector towards less carbon dioxide emissions requires a renewable electricity sector, as electric heating alternatives are only renewable if the electricity used is renewable. The heating sector consists of space and water heating but also implies process heating in the industry. Fossil fuels still play a major role in heat generation, particularly fossil gas. In 2018, 49% of German households were supplied with heat by direct gas heating and 13% by district heating [36]. In the industry, coal and gas are mainly used for the supply of process heat [37]. The use of renewable energy sources for heat generation is not yet as established as in the electricity sector, although their share in heating and cooling in Germany rose from 4.4% to 13.9% between 2000 and 2018 [38]. Also, the application of renewables is mainly used for generating low-temperature heat, lesser for process heat in the industry. The share of renewables is at only 5.3%, while coal and gas remain the dominating energy sources [39]. Further deployment of renewables could be implemented through electric furnaces and renewable gas, produced via renewable energy inputs. In the low-temperature heating sector, heat pumps, as an electric alternative to fossil boilers, can contribute to the decarbonization. The efficiency of heat pumps is higher for small differences in temperature. Therefore, they are primary only used in the low-temperature heating sector. Contrary, process heat also demands temperatures above 1000 °C. Therefore, renewable gas is the only option to decarbonize specific processes, according to Naegler et al. [40]. As a result, Biogas and Biomass are getting more relevant but are limited by the existing arable lands and grasslands [41]. Also, a renewable heating sector will rely on direct electric heat generation (e.g., heat pumps or electric (arc) furnaces) and thereby coupling the sectors electricity and heat. Furthermore, synthetic hydrogen has substantial potential in the heating sector, as well as in the transportation sector. Still, this would lead to a higher total electricity demand because of increased need for hydrogen produced by electrolysis. Consequently, the higher demand for electricity will also possibly generate the need for an expansion of the electricity grid.

Currently, the German electricity distribution networks have a line length of 1.7 million kilometres (km) in total and are operated by approximately 880 Distibution System Operators (DSOs) [42]. The existing transmission grid has a length of 35,000 km and is operated by four privately organized Transmission System Operators (TSOs) [43]. The transformation of the energy supply to renewable energies involves a profound change in the German electricity supply structure [44], which leads to new challenges for the grid infrastructure.

The final energy demand in Germany amounted to 9329 petajoules (PJ) in 2017, in which power and heat applications accounted for 70.5%. The remaining energy demand was caused by the transportation sector [45]. Even with efficiency improvements and climate goals, the final energy demand in the household sector increased slightly from 2383 to around 2430 PJ in the past 27 years [45]. Finally, the energy demand in the mobility sector increased by almost 376 PJ from 1990 to 2017 [45].

1.3. Literature Review

Since Conference of the Parties (COP) 21 in 2015 at the latest, limiting the effects of climate change and decarbonizing and decentralizing the existing energy systems has become a topic and a task not only for scientists but also for states and subnational state institutions. As the Renewable Energy Policy Network for the 21st Century (Ren21) stated in its annual report of 2018 [46], 169 countries have already set their own targets for renewable energies. The transformation of energy systems is underway around the world with varying degrees of ambition, as shown, among other things, by the large volumes of investment in renewable energy plants. Nevertheless, the Ren21 report also shows a slightly reduced effort globally: Compared to 2017, global investment has fallen, CO_2 emissions increased by 1.7% last year, some countries have retired from their own climate targets, and overall efforts are insufficient to meet the climate targets of the Paris Agreement [46]. That is why it is important that research continues on a global, supranational, national, and regional level in this area and that studies are being published that demonstrate the relevance of the issue and can put pressure on decision-makers.

There is a variety of studies available that analyze possible pathways for decarbonized energy systems. While some studies are focusing on a global context [47,48] or on a European level [49–53]. Connolly et al. [53] used the 2013 version of the EU reference scenario [54] to calculate a European energy system in 2050 with integrated transportation, heating and cooling and industry sectors, which relies on renewables by 100%. They conclude, that it is possible without using unsustainable amounts of biomass and by additional system costs of 12%. Following the question of technical feasibility and the burden that lies on the power sector and the European transmission grid, Zappa et al. [52] used various reference scenarios determining future power demands and data from entso-e, to conclude that the installed power generation capacity has to increase from 1 Terawatt (TW) to 1.9 TW in 2050. Around 8.5 Exajoule (EJ) from Biomass will be used in the power sector, compared to Connolly et al. [53] 13.5 EJ in the whole European energy system. Also using GENeSYS-MOD, Hainsch et al. [49] model a low carbon energy system for Europe. They conclude that achieving a target where global warming is limited to 1.5 is only feasible under certain conditions while staying below 2.0 will only generate 1.5% additional costs compared to the business as usual case. Using the Dynamic Investment and Dispatch Model for the Future European Electricity Market (dynELMOD), Gerbaulet et al. [50] calculate that PV throughout Europe, as in Germany, is only used half as much as wind power in 2050. Also, they figure out that by 2050, a 98% decarbonization can be achieved, which goes hand in hand with levelized costs for electricity of around 27–32 € per MWh.

Considering a global level with some regional detail, Ram et al. [48] conclude that 100% renewable energies are feasible, as well as levelized costs in electricity are falling, but are rising in heat supply. In contrast to Gerbaulet et al. [50], their calculations suggest that Germany’s renewable energy system will be based primarily on solar energy generation.

Considering the issue of imports and exports, the role of individual countries plays a decisive role. A breakdown for European countries is provided by Child et al. [51] who use the LUT Energy System Transition model also used by Ram et al. [48]. They come to the conclusion: power trade within Europe is increasing massively from 63 GW to 262 GW. They calculate that the United Kingdom, Ireland, Norway, Denmark, and the Baltic states will be exporters of electricity, while Germany will import 1% of its requirements.

The same questions arise also in the national context of Germany: numerous studies consider pathways towards a possible decarbonization of the German energy system [11,12,55–59]. However, the German studies are usually done on a national level and only seldomly in a federal context.

Pregger, Nitsch, and Naegler’s [55] study compares necessary developments for achieving the aims of the German federal government’s “Energy Concept” under different costs for technologies and resources. To accomplish the lower boundary of 80% emission reductions until 2050, they find that an increase of renewable power generation is needed, accompanied by the need for substantial efficiency gains across the sectors. In their base case scenario, they compute a rather moderate amount of installed renewable capacity of 179 GW in 2050.

Palzer and Henning [56] take a look at the electricity and heating system and conclude that given significant efficiency gains in the heating sector (40% to 50% of heat demand compared to 2010), both sectors can be decarbonized by 2050– with an installed renewable energy generation capacity of 465 GW. In another study, Henning and Palzer [57] also include the sectors transportation and industry and conclude that a transformation towards 80% GHG emission reduction is theoretically feasible, although additional costs would be around EUR 30 billion annually, compared to the reference case. Regarding the nearer future, Oei et al. [60] conclude in their study that Germany will not meet its intermediate targets for 2020 and 2030 if it keeps the current trends (and limited efforts). One main message is the fact that an extensive phase-out of coal-generated electricity until 2030 to meet the targets could be feasible without endangering the security of electricity supply.

While these studies do not put much weight on electricity import and export, Samadi et al. [58] point out that usual scenarios are relying on high values of net imports of electricity, thus needing fewer storage capacities but increasing technological, financial, and political complexity [58]. However, Pleßmann et al. [47] conclude that after modeling the demand for energy storage for a 100% renewable and thus fluctuating electricity supply, the integration of electricity storages will not increase the levelized costs of electricity (LCOE) in comparison to conventional energy sources. The question as to how important energy storage is for a 100% renewable energy system is also extensively discussed in a German context: In a comparing study, Cebulla et al. [61] found a large variance between the estimated requirements for electric energy storage in an energy system relying heavily on renewables: One cited study estimates a storage capacity of up to 83 TWh in a system that is 100% renewable (or 6.3 TWh in the case of 80% market penetration) [62]. By 2050, Child et al. [51] estimate that up to 147 TWh of storage capacity have to be built in Germany to compensate for grid fluctuations which is far higher than Hartmann's estimate which is even more astonishing, when having in mind, that this study calculated a fully integrated European power sector. Concentranting on Germany, Sinn [11] calculated a need for electric storages of around 16.3 TWh Schill et al. [12] however, argue that with the regulation of generation peaks from renewable energy plants, as well as sector coupling, there would be no need for large electricity storage additions. Today, there exist multiple storage technologies and solutions that can play a role in compensating the strong fluctuations in the feed-in of renewable energies. In this context, Zsiborács et al. [63] argue that European energy storage market developments and regulations which motivate the increased use of stationary energy storage systems are of importance for a successful renewable energy integration. Decentralized power storage systems, for example, can contribute to increasing local self-consumption and thus to relieving the pressure on distribution networks, as decentralized systems become more widespread [64].

With focus on the power sector and technical feasibilty within the transmission grids [65,66] also modeled the German energy system including demands for the transportation, heating and industry sectors. Different from other approaches, they chose to model in different steps which allowed them not only to have a simple cost optimization but also include some market and grid simulations. In both papers they conclude, that with a sufficient electrification of the non-power sectors an energy system largely decarbonized is feasible and that power to gas will pose as a main driver [65]. Furthermore, Müller et al. [65] also looked at cross-border power trade and conclude, that Germany will become a net importer on at the norther borders and a net exporter on all borders, making Germany a net exporterin 2050.

Regarding the electrification of the mobility sector, and the possible effects on the German power sector and grids, some studies have been published in recent years. Hanemann et al. [67] found out that vehicle-to-grid (V2G) charging mechanisms would be supportive for the stability of German power grids, would help to decrease electricity costs from renewables by increasing rates of utility and that a high CO_2-price would support the two aforementioned points. Furthermore, transnational powertrade could be reduced and the electrification of the transportation sector could go in hand with the decarbonization of the power sector [67]. More general, Schill and Gerbaulet [68] point out that not scarcity of energy should be of the policymakers' concerns but demand peaks. This means that a user-driven charging scheme will endanger the grid stability and support coal fired power plants, as they are used as a back up reserve. Further, price-driven or market-driven charging schemes will only work if an adequate CO_2-price is deployed. Just like V2G, a controlled charging would increase grid stabilities and support higher rates of utilisation of renewables thus, decrease the overall costs for electricity. In contrast to that, Loisel et al. [69], who examined different grid-to-vehicle and V2G-schemes, point out, that, as of today, battery technology is not mature enough to support such schemes and that in current pricing regimes of the power and mobility sector, electricity simply is worthier in the latter. Hence, a full integration of both sectors, as projected is still a far- away goal.

Considering the issue of imports and exports, the role of individual countries plays a decisive role.A breakdown for European countries is provided by Child et al. [51] who use the LUT Energy System Transition model also used by Ram et al. [48]. They come to the conclusion: power trade within Europe is increasing massively from 63 GW to 262 GW. They calculate thatthe United Kingdom, Ireland, Norway, Denmark, and the Baltic states will be exporters of electricity, while Germany will import 1% of its requirements.By 2050, they estimate up to 147 TWh of storage capacity will be built in Germany to compensate for grid fluctuations. Similar considerations are also carried out with the heating sector in connection with the electricity sector. Thus, Bloess [70] in her investigation of possible electrification mechanisms of space heating has determined that, similar to the mobility sector, flexibility options arise. Flexibilities in turn help the market penetration of renewables. On the other hand, there is great pressure on the electricity sector, with an additional demand for about 200 TWh of electricity by 2030 [70].

The high number of studies focusing on different sectors and regions and their interactions in the next decades presents how important this field of research is. Nevertheless, only a few studies try to have a holistic look and to model an energy system as a whole. One of the most recent studies that did that is published by Hansen et al. [59]. They conclude that even full decarbonization is possible by 2050 utilizing only domestic energy sources. This is achievable by strong sector coupling but at high costs of more than EUR 400 billion per year. Interestingly, decarbonizing the transport sector would make up 55–65% of the total costs. Touching on overall costs of the energy transformation, it becomes apparent that any non-implementation of measures would lead to even higher expenses in the long run. According to Stern [5], not acting would intensify climate change and lead to severe consequences for human life on this planet such as access to water, food production, health, and the environment. In sum, the costs and risks for not acting will be equivalent to losing at least 5% of global Gross Domestic Product (GDP) per year, respectively 20% if a wider range of risks is taken into account. However, reducing GHG emissions, in contrast, would limit the cost burden substantially to 1% [5].

Although a large number of different studies examine the German energy system and its future developments, a quantitative approach at the federal level is not yet comprehensively covered. In particular, data on the heating sector accurate to the federal state, as well as a desirable high level of detail for the location potentials of renewable energies are capable of extension and improvement is missing in these studies.

1.4. Research Question

This work aims to give further insight into the development of the German energy system by computing the sectors of power, heat, and transportation endogenously and coupled. The developed scenarios, which are described in the next chapter, shall stretch out a space of possible pathways. Results shall represent the techno-economical optimum and provide information on future technology mixes and pathways towards a 100% renewable energy system. Furthermore, this work intends to offer new insights to policymakers and the modeling community by contributing to existing literature gaps.

2. Methodology

2.1. Description of the Model

The next paragraphs provide some insights into the applied model. However, a detailed description of the mathematical formulation is not provided; at relevant passages, a reference to the respective literature is given.

2.1.1. Summary of GENeSYS-MOD

This study uses the Global Energy System Model (GENeSYS-MOD) v2.0 described by Löffler et al. [14] and Burandt et al. [15]. It is an open-source tool for the modeling of energy systems based on the Open Source Energy Modelling System (OSeMOSYS) by Howells et al. [71]. The model uses a system of linear equations to minimize total system costs while meeting energy demands and respecting externally defined constraints (see Appendix B for a more detailed description of the model structure and workings). GENeSYS-MOD allows to model multiple regions, time periods, and sectors.

Therefore, it enables to show the development of an energy system, encompassing the sectors power, heat, and transport for Germany on a federal level until 2050.

2.1.2. Basic Structure of the Model

Essentially, GENeSYS-MOD can be defined as a flow-based optimization model. Its structure is made up of a network of nodes which are connected with each other, as illustrated in Figure 1. The nodes, called technologies, represent all entities producing, using, or transforming energy, for instance, power plants, vehicles, storages, and heat pumps. The different technologies are connected by fuels, which represent all energy carriers, electricity or fossil fuels, or their proxies, such as transport.

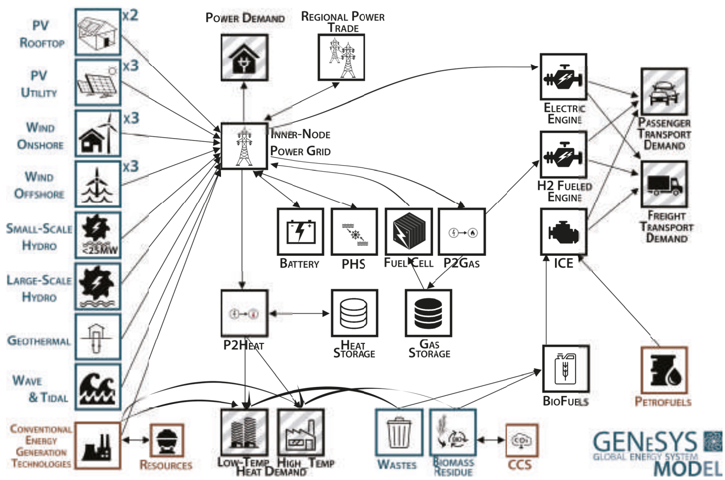

Figure 1. Structure of GENeSYS-MOD v2.0.

Energy demands are endogenously defined for every year and region and can be classified into heating, electricity, and transportation. Using a mixture of technologies and trade between different regions, GENeSYS-MOD aims to meet the given demands. The model seeks the minimization of total system costs, which are defined as the discounted costs of all regions over the model period. This includes investment costs, operating costs of technologies, trading costs of fuels, expansion costs of trade capacities, and penalties for the emission of CO_2. This objective is restricted by several constraints, which aim to depict real-life restrictions of an energy system, including maximum capacities and operational life spans. Furthermore, phase-out plans of several fossil fuels, as well as emission limits, are included under the given scenario.

For a more elaborate description of GENeSYS-MOD see the Appendix B, as well as Löffler et al. [14] and Burandt et al. [15].

2.1.3. Node Split

To analyze the development of the German energy system on a regional level, Germany was divided into a network of 16 nodes, each representing one federal state. Every node has its own energy demand, renewable potential, and existing capacities. Furthermore, there exist power transmission capacity limits between these notes according to the existing power transmission grid. In addition to the 16 nodes in Germany, neighbouring countries that are connected to Germany via a transition line are also represented by 9 nodes, to model the interlinking between Germany and its surrounding countries (following Hainsch et al. [49]). These nodes represent Denmark, Poland, the Czech Republic, Austria, Switzerland, France, and the Netherlands. Belgium and Luxembourg are gathered into one node—the BeLux node. The Scandinavian node combines Sweden, Norway, and Finland. Even though most constraints apply for each node individually, there are some constraints that apply to Germany as a whole. for example the emission targets are defined on national level not on state level.

2.2. Elaboration of the Scenarios

In the following paragraphs, three different scenarios for the energy system of Germany until the year 2050 are developed—namely European Island (EI), Green Democracy (GD), and Survival of the Fittest (SOTF). Each scenario draws up a different storyline regarding the global, European, and German trends in climate politics and the economy. The storylines were developed in a workshop with experts from governmental consultants, researchers and the business world, based on Europe's NDCs. Detailed information about the definition and elaboration of the narratives can also be found in [13]. Each scenario gives certain implications on the German energy system and thus, for the model. Developments for the global fuel prices, a price for CO_2—emissions, phase-out dates for certain technologies, and different energy demands in the sectors are derived from the storylines and implemented into the model. Relevant input data can be found in Appendix C.

It is important to say, that the narratives were designed on a global scale without specific implications for regions or nations. The derived scenarios then were designed after the model's aim and features were recognized. Therefore, forecasts or predictions of subjects that are not directly entangled with the model are not included. In this way, assumptions regarding the economic development and job markets are left untouched as well as possible policy measures that could not be integrated into the model's structure. Nevertheless, a brief examination of the stakeholders in politics, industry, and society was carried out to validate the legitimacy of the scenarios' assumptions (see Appendix A). Further, the aforementioned points are mapped via the different developments of energy demands in the various sectors. In light of these aspects, a comparison with European reference scenarios is generally difficult. Nevertheless, all scenarios are based on data and forecasts available and usually published by the countries' ministries or statistic authorities. Therefore, the baseline of this model is consistent in some aspects with, for example, the Reference Scenario of 2016 by the European Commission (*EC Ref16*) [54] or the EUCO scenarios (*EUCO323232.5*, *EUCO30*, and *EUCO27*) [72–74]: The efficiency gains in the individual scenarios are fairly consistent with the EUCO scenarios, with EI roughly correlating with *EUCO30* and GD with *EUCO323232.5*. Commodity prices here are based on world market prices and therefore differ somewhat from *EC Ref16*, especially in the gas sector, which has implications on resource prices paid in Europe. Technology costs and costs developments are largely identical to *EC Ref2016* (and not further modulated between scenarios). The assumptions on the development of the CO_2 price in the *EC Ref2016* scenario are fairly identical to the EI scenario, with neither scenario reflecting recent developments. However, the Weighted Average Cost of Capital (WACC) in our scenarios is assumed to be 5% compared to 7.5% in *EC Ref2016* [54]. In general, this study shows an increased sector coupling compared to the European average, with an accompanying increase in electricity consumption. Since SOTF and GD are not alternations of the baseline scenario but explorations of alternatives or extremes, commonalities to the European reference scenarios are fewer.

2.2.1. European Island Scenario

The EI scenario serves as the baseline scenario of this paper and is characterized by a strong European alliance, while global conflicts continue. Due to a strengthening of European institutions and greater influence of green parties, mutual politics focus on previously set climate goals. Countries within the EU are committed to enabling the EU to push for the fulfillment of the lower bounds of their climate goals, which is in the German case, an emission reduction of 40% in 2030, and 80% in 2050 compared to 1990. To realize these goals, phase-out dates for fossil fuels are set. The planned nuclear phase-out is enforced and carried out in 2022. Besides, the phase-out of hard coal and lignite for power production is set to 2035, and fossil gas and oil for power production to 2045. The heating sector and the transport sector continue to use fossil fuels. However, in terms of decarbonization, it is hoped for a spillover effect (E.g.: The heating sector is retrieving energy from a decarbonized power sector. Hence, the decarbonization in this sector is advancing, even without changing technology mix.) with increasing sector coupling.

As part of the mutual climate politics, an EU-wide CO_2 price is set (see Table 1) which rises rather slowly until 2035 but increases momentum afterward, until it reaches 85 € per t CO_2 in 2050 (With an increase of 1.50 € per year, a ton of CO_2 would cost 12.50 € in 2019. However, the European Energy Exchange (EEX) lists European Emission Allowances varying between 18–26 € per t CO_2 in 2019. www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#! Last accessed: 25 May 2019). World market prices for fossil fuels hard coal, oil, and fossil gas are influenced by two opposing trends: Due to increasing worldwide demand, decreasing availability, and political instability outside the EU, prices for fossil fuels increase. However, a decrease in demand in the EU and the effect of governmentally set phase-outs reduces the price increases slightly (see Table A2). These assumptions are based on the "450 ppm scenario" from the World Energy Outlook 2016 [75] and are adapted to the following scenarios as well.

Table 1. Overview of policy measures implemented in the model for the three different scenarios.

	European Island [EI]	Green Democracy [GD]	Surfival of the Fittest [SOTF]
linear increase of the CO_2 tax from €5 per t in 2015	to €35 in 2030 and to €85 in 2050	to €130 in 2050	to €15 in 2035 to €50 in 2050
limit the CO_2 emissions compared to 1990 by	40% in 2030 80% in 2050	55% in 2030 95% in 2050	no limit
phase-out in the electricity sector	Lignite in 2035 hard coal in 2035 gas/oil in 2045	Lignite in 2025 hard coal in 2030 gas/oil in 2035	no phase-outs

2.2.2. Green Democracy Scenario

Characterized by a reduction of international tensions, increased communication between stakeholders, and a holistic approach, the GD scenario visualizes the effects of fast action towards a sustainable energy system.

Within this scenario, the public opinion plays a vital role, as they put pressure on policymakers to advance climate protection, comparable to what the "Fridays for Future" movement achieves currently. Therefore, Germany sets itself a CO_2 reduction goal based on the NDCs. With 55% (2030) and 95% (2050), less CO_2 emissions compared to 1990 levels, Germany focuses on the more ambitious targets. This includes the sector-specific goals of an emission reduction by 2030 in the transport sector by 40% and in the space heating sector by 67%, both compared to 1990 [22].

Derived from those developments, Germany carries out its nuclear phase-out until 2022. In comparison to the EI scenario, fossil fuels phase-out are earlier due to prior interventions and increasingly cost-effective renewable energies. The phase-out of fossil fuels for power generation is set in 2025 for lignite, in 2030 for hard coal, and in 2035 for fossil gas and oil.

The growing efforts for climate protection, and therefore, a related decrease in demand for fossil fuels leads to a slightly falling price for conventional energy sources (likewise to EI). At the same time, the CO_2 price increases from €5 in 2015 to €130 in 2050 in a linear manner. This increase is due to the strong focus on climate action, which includes that all sectors are covered with emission prices. Especially in previously excluded sectors, effects will become noticeable, such as the transportation sector. Due to increasing urbanization and population, metropolitan areas will drastically change, which makes a holistic planning process for sustainable energy supply and infrastructure necessary.

2.2.3. Survival of the Fittest

In the SOTF scenario, the world is presented as one that has regressed from current climate policies to go back towards a more protectionist and nationalist environment. The scenario does not represent a world that is in complete refusal of climate problems, but rather one that prioritizes other issues, like national conflicts, conservative movements, and breakdowns of partnerships, until the effects of abrupt climate change are immediate and drastic.

Until 2035, the main driver is the need for energy security and independence, while the NDCs are mostly ignored. Interruptions in global trade as a result of protectionism lead to high prices for fossil fuels as well as imported technologies. Governments may choose to use renewables to gain energy independence but have no preference over conventional energy carriers.

In Germany, this scenario is marked by increasingly high prices for gas and other fossil fuel imports (see Table A2), as well as a slower rate of technological innovation. Consequently, already existing resources and infrastructures is used more than in the other scenarios, including reviving Germany's lignite reserves. Government-based emission initiatives are non-existent in the first half of the modeled period, while the carbon price is kept low at only €5 per t CO_2 in 2015, increasing to €15 per t CO_2 by 2035. (This increase is smaller than the actual increase of the CO_2 price from 2015 to 2019 reaching €25 per t CO_2).

From 2035 on, when the negative effects of climate change are even more visible, the focus starts to shift towards climate policy to mitigate further damages. From then on, the carbon price is increased linearly up to €50 per t CO_2 in 2050. Renewables are supported, leading to falling prices, however, no phase-outs for fossil fuels are set. This can be traced back to a growing focus on more acute global conflicts. Hence, the development of the energy system and eventual fossil fuel phase-outs are fully market-driven, given the cost assumptions.

3. Results

In the following chapter, the model results of the scenarios are discussed. In doing so, respective figures specifying the power, heat, and transport sector are presented and elaborated on. The graphs are resolved in five-year time steps and show the trend of the investigated sector in the period from 2015 to 2050, in accordance with the model calculations.

3.1. Final Energy

As Figure 2 illustrates, Germany's final energy consumption decreases along the scenarios' development paths by 2050. The decrease in final energy demand is due to decreasing demands in the different sectors: better insulation of the housing structure (see Figure 6), market penetration of electric vehicles, more efficient electric applications and a slow reshaping of the industry landscape (see Figure 7) have a significant impact on the amount of energy needed. On the other hand the electrification of different sectors plays a key role, which is reflected in increasing electricity production (see Figure 3). The paths displayed have significant points and trends for the various scenarios that represent the cornerstones of the transformation of the energy system. All scenarios are affected by the phase-out of nuclear power production set for each scenario. However, the gradual trend towards the decommissioning of coal-fired and fossil-fired energy generation and its use in different sectors is reflected in individual phase-out dates for the scenarios. Common in all scenarios is the nearly constant use of biomass and hydropower until 2050, as its potential is almost at its maximum at the beginning of the model period. A more detailed overview of the sector transformations is presented in the following model results.

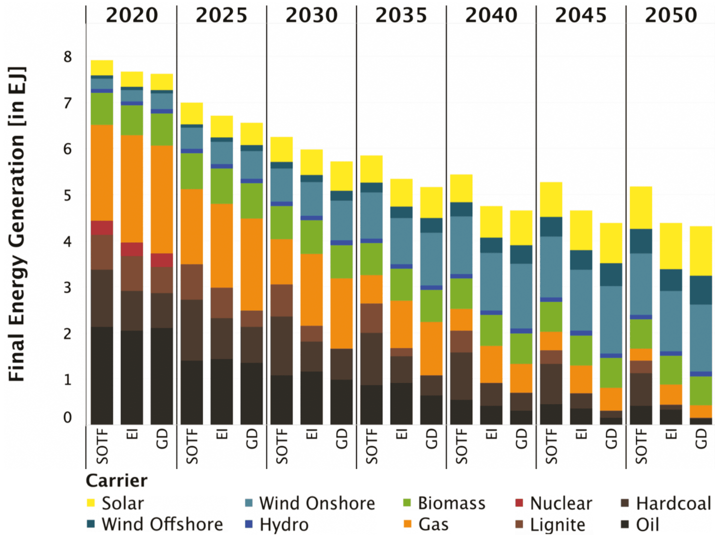

Figure 2. Development of Germany's final energy generation according to the respective scenario.

Survival of the Fittest The SOTF scenario has the most carbon-intensive transformation path and, at 5180 PJ, has the comparatively highest final energy demand in 2050, which is attributed to assumed low efficiency gains. Also, in this scenario, there are hardly any policy-driven restrictions such as phase-outs, so that model decisions, in this case, are primarily price-driven. Although the consumption of lignite (−70%), oil (−85%), and gas (−88%) are significantly reduced by 2050 compared to 2015, the use of hard coal decreases only slightly (−34%). The primary purpose of hard coal in the energy system of 2050 is to provide industrial high-temperature heat. Even though there is no phase-out date set for hard coal, it does no longer play a role in the electricity sector from 2040 on (see Figure 3). Compared to the other scenarios, renewable technologies are the last and least to expand in this scenario. Until 2050, the production of solar energy increases by 724 PJ (+370%) and wind energy by 1663 PJ (+780%).

European Island The EI scenario, as a reference case, accounts for only about half of final energy consumption in 2050, with 4388 PJ, compared to the base year 2015. Lignite is being phased-out in 2035. From 2035, hard coal no longer plays a role in the electricity sector, but is then only used for the medium- and high-temperature industrial heat generation, with decreasing volumes. The consumption of hard coal is reduced by 717 PJ (−87%) by the end of 2050. Oil as an energy carrier is drastically reduced by 2365 PJ (−86%) until 2050, in particular in the transport sector and residential low-temperature heat generation. However, it is still used for transportation to a limited extent in 2050. The use of gas (particularly fossil gas) also falls by 1962 PJ (−82%). Accordingly, the consumption of fossil gas in the industrial sector is steadily decreasing, but is being replaced to a low extent by synthetic gas. On the renewable technology side, the expansion of wind power generation is the most important. Power production from offshore wind will increase by 453 PJ (+1562%), for onshore wind even by 1120 PJ (+602%) until 2050. Solar energy generation is used for power generation through open field PV and rooftop PV systems. Furthermore, solar thermal systems are applied in residential low-temperature heat generation. With an increase of 797 PJ (+387%), solar energy likewise plays a major role in the renewable transformation path.

Green Democracy The GD scenario, which reflects the most ambitious transformation path, shows a reduction of the final energy demand by 48% (4317 PJ). The reduction rates of conventional technologies, over the entire model period, are only slightly lower than in the reference scenario (EI). However, due to strict guidelines regarding the reduction path, these reductions are achieved earlier, which goes hand in hand with the expansion of renewable technologies. As early as 2030, lignite is completely substituted by renewable sources and coal technologies are no longer used for power production (see Figure 3). By 2050, hard coal, which previously played an important role in high-temperature industrial heating, is phased out in this sector. Even stronger than in the other scenarios, oil experiences a significant drop of 2634 PJ (−96%), primarily through reductions in the transport sector. Further, it loses its role in the area of low-temperature heat generation in 2030 and from then on is only used in the transport sector. Concerning gas, it is noticeable that the utilization of fossil gas in the individual sectors is strongly declining while small quantities are substituted by the use of synthetic gas. In total, however, gas consumption declines by 2166 PJ (−89%) by 2050.

On the contrary, the technologies of wind power and solar energy have significantly higher growth rates. Led by onshore wind power with growth of 1292 PJ (+783%), and followed by solar power 860 PJ (+395%) and offshore wind power 591 PJ (+1555%), the renewable expansion in total lies slightly higher than in the other scenarios considered.

3.2. Power Sector

In all three scenarios, the energy system of Germany experiences a strong coupling of the power sector with the heat and transportation sector. This can be observed in the increasing generation of power see Figure 3. Among the scenarios, there are some variations in the power sector which are depicted more detailed in the following paragraphs. Again, biomass and hydropower contribute to the system in all scenarios but stay rather constant in generation due to almost exhausted hydro potentials in Germany and no added capacity for biomass in the power sector.

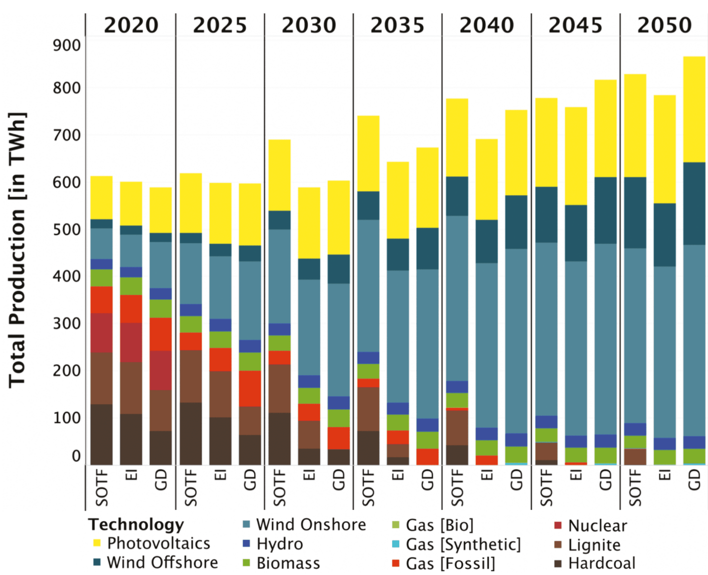

Figure 3. Development of Germany's power production according to the respective scenario.

When looking at electricity exports and imports of the federal states, it is noticeable that not only the electricity transported across federal state borders increases per year but also the inter-temporal fluctuations of the values between individual time slices. The model has two options available for absorbing strong volatilities in electricity production with high shares of variable renewable energy sources and for keeping the electricity grid stable even in dark lull periods. On the one hand, the model is allowed to expand the power grid to a certain percentage. To count in local resistance and lengthy approval procedures, the grid expansion was limited to 20% existing capacity per 5-year period. The second option is the use of intermediate storage facilities. Since the potential of pumped storage power plants in Germany is low and completely exhausted early on, lithium-ion battery storage systems are being introduced into the power grid. Depending on the scenario, large quantities of electricity will be temporarily stored in 2050. In GD this is 50.7 TWh in 2050, in EI 30 TWh, and in SOTF 20 TWh. Power-to-Gas technologies are another measure, as discussed in more detail in Section 3.3.

Survival of the Fittest The transformation of the power sector is slower than in the other two scenarios. The generation from hard coal and lignite stays rather constant in the first ten years. Nevertheless, in 2025 more than 50% of the electricity generation comes from renewable sources. The total electricity demand of SOTF is the highest among the three scenarios, due to fewer incentives to save energy, mainly in the heating sector, but also in general. Therefore, the added capacity of renewables in SOTF and EI is comparable. Overall, the generation by conventional sources declines. Lignite stays the prevalent conventional source, due to the comparably lower costs to hard coal, and fossil gas. In 2050 hard coal is phased out due to rising global prices for coal. In 2050, the electricity generation is 95% renewable even in this scenario without CO_2—targets, due to cost advantages.

European Island The development in the first 20 years is characterized by the phase-out of one energy carrier each timestep of five years: nuclear in 2025, hard coal in 2030, lignite in 2035, and fossil gas in 2040. The renewable sources wind and PV replace this conventional power generation. Already in 2035, the energy system in EI is 95% supplied with electricity from renewable sources; only fossil gas remains as a conventional source. From 2030 onwards, the total power generation increases by around 10 TWh each year, due to the increasing sector coupling, resulting in a generation of 875 TWh in 2050. In 2050 for Germany the generation from wind turbines is twice as high as the generation from PV.

Green Democracy Until 2025, the nuclear phase-out and the reduction of power generation from hard coal and lignite by 50% is replaced by power generation via wind and sun. Therefore, additional capacities of 85 GW are installed. The abandonment of lignite for electricity production is connected with a decrease in hard coal or fossil gas generation, with a reduction of fossil gas and hard coal of nearly 50% by 2030. In 2035 hard coal is phased out without resulting in a temporary increase of fossil gas. Instead, the more volatile electricity generation from wind turbines and PV is balanced via power trade, hydropower, and battery storage. In 2040, the electricity generation in Germany is 100% renewable and decarbonized. Electricity production via wind turbines contributes two thirds to the generation, PV a quarter. Synthetic gas is mainly used in the industry heavy region of North Rhine-Westphalia. After 2040, only onshore wind turbines and PV utilities are built, increasing the power production by additional 100 TWh. The expansion of renewable energy sources adds up to 180 GW onshore wind, 39 GW offshore wind, and 99 GW capacity connected to the grid in 2050. In the same time, the demand for electricity in the heat and transport sector increases by 130 TWh. In general, since low-carbon electricity generation technologies are available at low costs, the electricity sector is the first to be decarbonized.

Figure 4 shows the regional breakdown of the power production for 2020, 2030, and 2050. It can be seen, that, over the years, each federal state will have increased power production. However, the change in the coastal states might be the biggest: Yielding the potential from offshore windpower, Lower Saxony, Schleswig Holstein, and Mecklenburg-Vorpommern will become net exporters of energy. Especially the exchange of power between Lower Saxony and North Rhine-Westphalia is very important, as North Rhine-Westphalia is depending on large amounts of electricity produced by wind turbines from the north. Furthermore, in 2030, North Rhine-Westphalia will be one of the last states with significant shares of conventionally produced power. Another state with conventional generation is the city-state of Bremen, which is close to the global coal markets with its harbor. Furthermore, states like Hesse, Thuringia, and Saxony-Anhalt, which have low production rates in 2015 will increase their production by the factor three or higher. This change in production rates is a consequence of the different technologies used for electricity generation. In 2015 with a high share of fossil generation, the power plants are located near demand centers or mining areas. Contrary, in 2050, with mainly electricity generation from wind and PV, the place of the generation is determined by renewable potentials and available space. Consequently, city states like Berlin or Hamburg, Hamburg or Bremen will be more dependent on importing electricity from neighboring states, as they will shut down own production capacities (The 2019-elected local government of Bremen note in their coalition agreement of July to phase out of coal already in 2023. This would affect three powerplants in Bremen [76].). These developments go along with an increase in electricity transmission and storage.

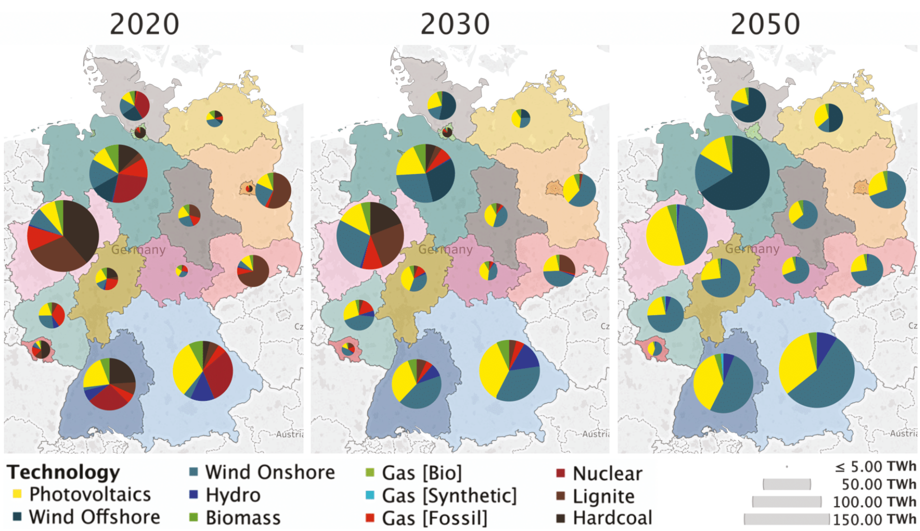

Figure 4. Regional development of Germany's power production for the Green Democracy scenario.

3.3. Sector Coupling

With increasing decarbonization of the sectors of heat and transportation, they also demand more electricity. As Figure 5 demonstrates, in 2015, the power demand from sector-coupling is well below 100 TWh per year, consisting mainly of demand in the industry sector. Over the next 15 years, the power use in sector coupling increases due to the electrification of space heating in the residential area and to a smaller extent by the market penetration of Battery Electric Vehicles (BEVs) and an increase of electric trains. By 2030, SOTF has the highest amount of electricity used in other sectors, due to less energy efficient buildings and overall energy savings. This electrification is also linked to an increase in fossil fuel prices on the world market. However, in 2050, the lead of SOTF is overtaken by EI and GD, where stricter mitigation goals have to be achieved. While the power demand in residential applications stays rather constant over the latter 20 years, the industry sector becomes decarbonized to a high extent, with a five fold power demand in the GD scenario. Passenger transport is already relying on electricity in the 2030s, with an increasing power demand until 2050. Freight transport has the same, but delayed development. At the end of the modeled period, hydrogen produced by electrolysis plays a significant role. The produced hydrogen is either used directly in the transportation sector or reformed into synthetic gas. In the GD scenario, hydrogen and synthetic gas are used primarily in low-temperature heating. Furthermore, small parts of high temperature heat are generated by synthetic gas in the EI and GD scenarios. In general, the energy that is transferred from the power sector to the transport and heating sector exceeds the 50%-mark of total power production in 2045 in GD, in 2050 in EI and reaches 46.3% in the SOTF scenario at the end of the model period.

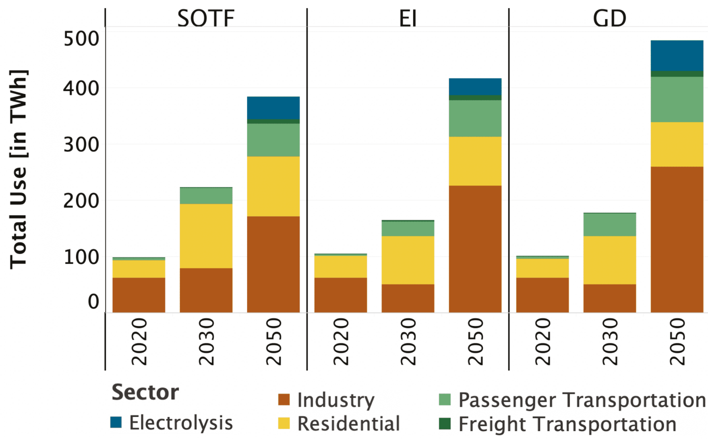

Figure 5. Use of power for sector coupling technologies by type according to the respective scenario.

3.4. Heat Production

The model results concerning heat production are displayed using the GD scenario as it provides the most drastic changes. The heating sector is divided into residential heating (warm water and space heating) and industrial heating, which is broken up into demands for low temperature heat (process heating and space heating below 100 °C), medium temperature heat, and high temperature heat (above 1000 °C).

Residential heat demand The demand for residential space heat, warm water, and energy for food preparation is with 750 TWh higher than the total heat demand in the industrial sector. However, due to the expected improved insulation of the German building structure, the demand will decrease until the end of the model period by one third, as Figure 6 shows. In 2015, the vast majority of demand is met using oil and fossil gas. Only small fractions are supplied by heat pumps or biomass. Until 2030, oil will be phased out, while the share of fossil gas stays rather constant. Air-based heat pumps are constantly gaining in importance but will soon reach their potential limit. Ground-based heat pumps will have their first appearance in 2030, but will also not reach higher market penetration rates. Close to the end of the model period, solar thermal technologies will also be helpful to decrease the share of fossil gas in this sector. However, solar thermal has to compete against PV modules on a limited space on roofs, which makes them interesting solutions only in regions, where electricity is rather abundant. To decarbonize this sector further in 2050, with decreasing costs for electrolysis and methanization, synthetic gas might also be a possible substitute for fossil gas.

Industrial heat demand In 2015, the total demand for industry heat was about 570 TWh per year, of which, low and medium temperature heat demand was at 220 TWh each. This number declines to 370 TWh per year in 2050, supported by efficiency gains from the use of power to heat technologies, as Figure 7 presents. In the first years, a slight overproduction of low temperature heat is measurable as the model can produce heat as a byproduct of the power generation of industrial power plants. Overcapacities will soon be eliminated as the expensive oil firing and emission-heavy lignite firing heating applications are dismantled. Interestingly, the share of the more expensive fossil gas is decreasing earlier than hard coal. This is partly due to the fact that hard coal is extensively used in high temperature applications (e.g., blast furnaces for steel melting), where alternatives are rather expensive and thus, decarbonization is more difficult. In the low and medium temperature range, biomass poses as a good substitute to conventional energy carriers, but availability is limited and this sector is in competition with the other sectors as well. From 2030 on, solar thermal modules are installed on roofs, but also here, the heating sector is in direct competition with the power sector due to limited roof space. In the medium temperature range, direct electric applications become very important in the second half of the model period. In the high temperature range, molten (steel/aluminium) electrolysis substitutes the remaining coal fractions in the later years. Synthetic gas is only used in small shares, mostly in low temperature heat applications.

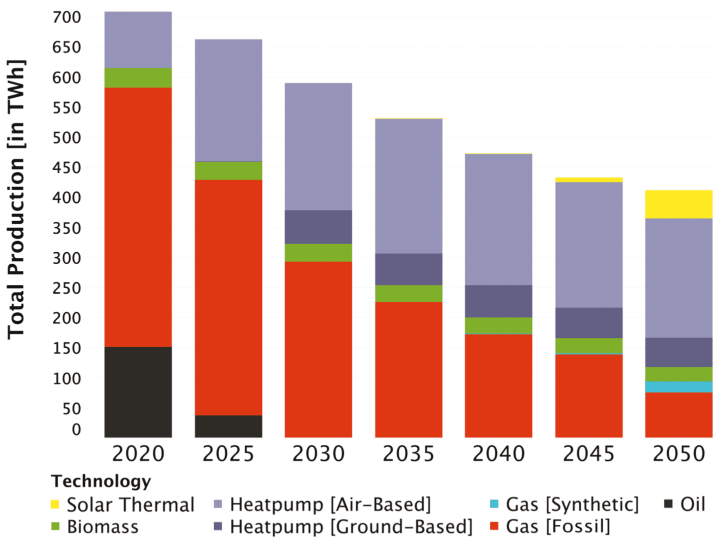

Figure 6. Development of residential low temperature heat production by carrier for the Green Democracy scenario.

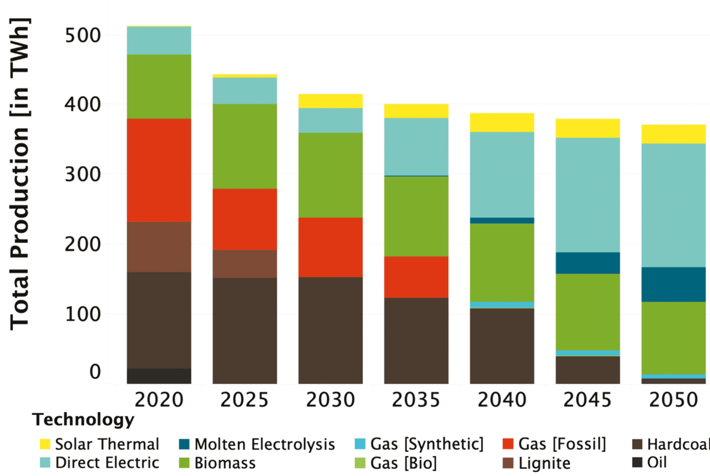

Figure 7. Development of the industrial heating sector, including the low, medium, and high temperature heat range for GD.

3.5. Transportation

The transportation sector is split up in passenger and freight transport, each of which has three different modal types: Road, rail, and air for passenger or ship for freight transport. To present the results, only the GD scenario is depicted. However, the other two scenarios have resembling results. For a visualization of the result refer to the Appendix D Figures A2 and A3.

Freight Transport The total volume of tons of freight transported in Germany will be steadily increasing by 50% until 2050. To cope with the rising traffic, an increasing share of freight will be transported via train. However, the preferred fuel for rail transport will be petrofuels until the '30s. After that, the share of electrified rail transport will increase sharply in relative as well as in total numbers. In 2050, 32% of freight kilometers are by rail with electric trains, only 3.5% by conventional trains. The road-based freight transport is also growing in total numbers in the first half of the model period. Internal combustion engines are the predominant technology used. Only in some years, petrofuels are being utilized. Beginning in 2030, a network of streets with overhead power supply is being set up. This rather expensive way to decarbonize the freight transport becomes an important factor in 2040 with increasing shares of up to 30% in 2050. Heavy-duty freight vehicles with only batteries will not penetrate the market extensively but have a small but constant share. Internal combustion engines and petrofuels will be dominant over the whole model period.

Passenger Transport Unlike freight transport, passenger transport will have a stagnating volume over the years, with an increasing share of traffic handled by rail. In absolute numbers, the volume of passenger kilometers handled by rail increases from 87.2 billion person-kilometers (GPkm) per year to 291.5 GPkm. Road based traffic will be handled mainly by BEVs. The market penetration will increase from 15% in 2025 to 62% in 2050. Plug-In Hybrid Electric Vehicles (PHEVs) will stay in a niche with a share of only 0.11 % until 2040. Even after that, this technology is only used as an intermediate solution or bridging technology. Biofuels are not an alternative in the long term but being used in the years 2020 and 2050, as an intermediate solution to achieve the reduction targets.

3.6. Emissions

Figure 8 compares the various developments in annual emissions and total CO_2 emissions and puts them into relation with carbon budgets. The left y-axis and the clomumns represent the annual CO_2 emissions. Here, the main differences in the scenarios are visible: GD shows a drastic decline in annual emissions on account of drastic policy measures, namely the phase out of coal in the power sector early on. Together with a quick electrification of the other sectors and steeply increasing costs of CO_2, the emissions can be more than halved in between 2020 and 2035. These measures also lead to very high rates of emission reduction in 2050, even though a net zero, as German chancellor Angela Merkel announced in May 2019, to be an objective for 2050 is not feasible under the model's and scenario's assumptions (www.tagesschau.de/inland/merkel-klima-111.html Last accessed: 25 June 2019). EI follows the same pattern, however, less strict reduction targets and policy measures, as well as later coal phase outs will result in higher annual emissions for the entire modeling period. This throws a rather negative picture on the current climate efforts of the Federal Government, considering that this scenario is largely in line with the decisions of the Coal Commission, as far as the phase out of coal from the electricity sector is concerned (see also Section 1.2). SOTF resembles future developments of annual emission when all mitigation action is mainly driven by the market powers of resource prices, demands and technology development and costs. As Figure 8 clearly shows, the emission reduction is not sufficient enough and is more than twice as high as the emission from EI. Unlike both other scenarios the pathway is not characterized by a period of high reduction rates, instead it constantly declines by decreasing demand and assumed increasing fuel costs.

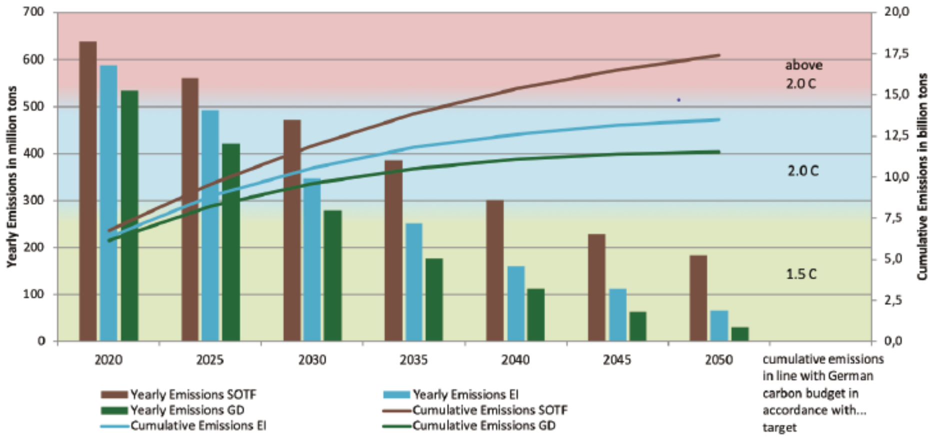

Figure 8. Development of yearly and cumulative CO_2 emissions per scenario. CO_2 emissions from material conversions in industry processes, meat production, and land use, land use change and forestry (LULUCF) land use, land use change and forestry (LULUCF) are not taken into account. The green area marks being calculated in the model and thus excluded from the German carbon budget for 1.5 °C if the global carbon budget was shared according to the countries' population. The blue marks the same share for the 2.0 °C target, the red area marks the the remaining German carbon budget for 1.5 °C target if it was shared according to the countries' GDP. Calculations is L based on 2015. The global carbon budget according to Rogelj et al. [1] was taken and counted back to 2015. Share the share of Germany's population in the world in 2015: 1.12%.

The right *y*-axis of Figure 8 represents the over the model period accumulated emissions of all three scenarios in comparison to certain carbon budgets. The global carbon budget according to climateactiontracker.org (climateactiontracker.org is a cumulative project by the NGOs Climate Analysis, NewClimate Institute, Ecofys and the Potsdam Institute for Climate Impact Research and is funded by the ClimateWorks Foundateion and the German BMU via the International Climate Initiative.) was taken, split up by the German share of the global population and calculated for 2015. All carbon budgets are calculated until the year 2100, while this study's time horizon ends in 2050. Especially the SOTF and EI scenarios, therefore, have to undergoo further decarbonization action after 2050 to stay within budget limits. Most strikingly, this figure shows, that not even GD will stay within the Paris Agreement's target to limit the global warming below 2 °C and aiming at 1.5 °C (see also Section 1 and 1.1. Nevertheless, by comparing the development of the three scenarios' cumulative emissions, one can see that early, drastic measures are helping a lot to decrease overall emissions: The final cumulative emissions will differ by 33% between GD and SOTF.

3.7. Model Limitation and Further Research

The model was set up using available data for technology costs and potentials as well as demands for power, heat, as well as personal and freight transport. The model was calibrated with data for the base year of 2015. Installed power plant capacity, as well as demands for power and heat, kilometers travelled, and freight moved can be found in different governmental statistics agencies.

However, GENeSYS-MOD lacks some features macro-economical models might provide, thus exogeneously defined demand projections had to be included. This also includes assumptions concerning efficiency gains and progress of technological progress. This forces the model into a corridor of boundaries which are set up under somewhat different assumptions than the scenarios' narratives. Nevertheless, under- or overestimations of technologies and their impact on developments are inevitable. Hence, the approach to use three different story lines is an attempt to mitigate this bias.

Another characterization of the model is its linearity: As soon as one technology is marginally cheaper than an alternative, the model will choose this one until there is a constraint. This usually leads to jumps in the utilization of technologies and drastic technology swaps. To circumvent this, smoothing factors where included, which, on the one hand pose as restrictions on the model's freedom, while on the other hand also pose as a tool to calibrate the model to fit into realistic predictions.

Furthermore, GENeSYS-MOD uses relatively large time steps of five years with 16 annual time slices. Each year is separated into four seasons and four time slices of different length, each to represent a typical demand curve over the day (night, morning, midday, afternoon) of each season (for the length of each time-slice refer to Burandt et al. [15]). Compared to load curves in energy economics with a resolution of 15 min time steps, the possible loss of information seems quite high. Still, the deviation is small, as [77] found out comparing an enhanced OSeMOSYS implementation with 16 time slices to a full hourly dispatch model. Nevertheless, a more granular model would be optimal and might be subject to further research.

The lack of integration and calculation of other GHG emissions apart from CO_2 is another limiting point of the model and its results. Primarily methane, although it has a shorter residence time in the atmosphere, has a strong GHG effect and is therefore not irrelevant for Germany's climate balance. The same also applies to the conversion of substances in industry, which sometimes emit large quantities. All of this is not further illustrated in this model, but represent about 10 to 20 percent of total German emissions [78]. An integration of emissions outside of the energy market and emissions of other GHG are also subject to further research.

4. Conclusions

This study analyzes three possible scenarios for the German energy transformation in the light of climate change and global resource scarcity. The scenarios, namely European Island (EI), Green Democracy (GD), and Survival of the Fittest (SOTF), outline possible pathways in the period between 2015 and 2050, including different phase-out policies, carbon- and resource price developments, and efficiency improvements. Therefore, the sector coupling model Global Energy System Model was applied. Irrespective of a scenario-specific consideration, the expansion of wind energy and PV play a major role in the cost-optimized development of the German energy system, especially in the electricity sector (see Section 3.2). The expansion of renewable energies for power generation is a key element on the development path to combine low costs with low emissions. A discernible trend towards increasing electricity demand corresponds to the gradual electrification of the individual sectors and the utilization of electrolysis to provide hydrogen and methane as alternative fuels (see Section 3.3). Nuclear energy thereby is neither required in the long term nor as a bridging technology. The use of power-operated heatpumps plays an important role in the provision of residential space heating and is gradually replacing fossil fuels such as oil and fossil gas. In the industrial sector, emission reductions in high-temperature heat generation exclusively require electrification, whereas for medium- and especially low-industrial heat generation, biomass can be a vital part of possible decarbonization pathways (see Section 3.4). In the transport sector, battery-powered passenger vehicles and electric overhead freight trucks are gradually replacing conventional combustion engines. The transport sector electrification is also reflected in the expansion of electric rail transport (see Section 3.5).

In EI and GD, the model calculated the cost optimal energy system given the desired emission reduction pathway based on Germany's climate protection targets [22]. As a result of the ambitious restrictions of the GD scenario already in the 2020's, the associated early emission reductions demonstrate that the time is a decisive determinant for achieving the lowest possible cumulative emissions. However, in the SOTF scenario, neither emissions constraints nor fossil phase-outs were applied. Even without any given emissions reduction pathway, Germany still reduces its yearly emissions by 85% based on 1990 level. This represents the lower boundary of the targets Germany has defined for 2050. However, the measures are not sufficient to reach the 1.5- nor 2-degree limit and therefore not in line with the climate targets of the Paris agreement. The decisive factor for the remaining emissions in SOTF is the high-temperature heat sector powered by hard coal. This underlines that the phase-out from coal as an energy carrier is a major key for a successful renewable energy transition. This transformation is highly needed to start taking action to face the real threats of climate change. A net decarbonization in Germany by 2050 is needed to comply with internationally agreed on-climate targets.

More general, these results show, that a country with a relatively high energy consumption per inhabitant or per ground area is able to decarbonize its energy system by large fractions within a given timeframe. Being an early adopter, Germany was able to push first decarbonization methods early on and also gain experience in the deployment and application of renewable technologies. Nevertheless, the current system and industries surrounding it are relucant to undergo big changes, as hesitancies among industry association, local politics and even the society shows. On the other hand, decarbonization and deep intergration of all sectors also offer chances in flexibilization of energy supplies and demands, offer jobs even in rather underdeveloped areas and help decrease accumulation of power and influence on few stakeholders or regions in Europe as wind and solar irradiance are rather omnipresent sources of energy. Even though, the cross boarder trade of electricity decreases with a decentralization of the power generation landscape, there is a demand for grid expansions in between regions of supply and demand. While the regions of demand remain unchanged, the regions of supply may differ in future decades. Other countries, that are also trying to decarbonize their energy system can take some valuable insights: (A) Many countries have a lower power demand by ground area while even having a higher energy supply, due to better wind or solar exposition. This means, the endeavours Germany has to take to decarbonize its system might not be as high for another country. (B) Deployment of solar farms and wind farms is necessary, even in regions where the relative power demand is quite low. This might not be accepted by the people affected by it, therefore it is important to start a discussion early on and find concepts of participation to counteract movements lead by the "not in my backyard" (NIMBY)-principle. The same NIMBY-thinking applies for needed grid expansions measures and thus needs to be addressed early on. (C) Conflicts of distribution will rather increase than decrease, since technologies from all sectors will have to compete for resources. This can be examplified in the case of biomass: Being the cheapest way to decarbonize several processes and applications, each sector would like to use as much of it as possible. Nevertheless, in some applications biomass might be worthier than in others. Therefore, in the planning of future generation technologies and demands, it is indispensable to always look at the energy system as a whole and then to decide on means of distribution.

The results presented in this paper pose as a first successful elaboration and implementation on the complete decarbonized German energy system on a federal level. Further next steps include a more detailed representation of the largest branches of industry in Germany and their decarbonization options. This could more accurately resolve and endogenously calculate the requirements for process heat, which have so far only been considered superficially, instead of prescribing exogenously.

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Conflicts of Interest: The authors declare no conflict of interest.

Abbreviations

The following abbreviations are used in this manuscript:

BDEW	German Association of Energy and Water Industries
BDI	Federation of German Industries
BEE	German Renewable Energy Federation
BEV	Battery-Electric Vehicle
BMBF	German Ministry for Education and Research
BMU	German Ministry of the Environment, Nature Conservation,and Nuclear Safety
BMWi	Germany Ministry for Economic Affairs and Energy
CHP	combined heat and power
COP	Conference of the Parties
CSU	Christian Social Union in Bavaria
DSO	Distribution System Operator
DUH	Deutsche Umwelthilfe e.V.
dynELMOD	Dynamic, Investment and Dispatch, Model, for the Future European Electricity Market
EEG	German Renewable Green Energy Act
EI	European Island
EJ	Exajoule
EnWG	Energy Industry Act
ETS	Emission Trading System
EU	European Union
GD	Green Democracy
GDP	Gross Domestic Product
GENeSYS-MOD	Global Energy System Model
GHG	Greenhouse Gas
GPkm	billion person-kilometers
GW	Gigawatt
IGBCE	Labour Union of the Mining, Chemical and Energy Industries
IPCC	Intergovernmental Panel on Climate Change
km	kilometer
LCOE	Levelized Costs of Electricty
LULUCF	Land Use, Land Use Change and Forestry
NDC	Nationally Determined Contribution
NIMBY	"Not in my Backyard"
OSeMOSYS	Open Source Energy Modelling System
PHEV	Plug-In Hybrid Electric Vehicle
PJ	Petajoule
ppm	parts per million
PV	Photovoltaics
SOTF	Survival of the Fittest
TSO	Transmission Grid Operator
TW	Terawatt
TWh	Terawatt Hour
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
V2G	Vehicle to Grid
VDA	German Association of the Automotive Industry
VDMA	Mechanical Engineering Industry Association
WACC	Weighted Average Cost of Capital

Appendix A. Stakeholder of the German Energiewende

Germany has a federal system with the fundamental principle of subsidiary. Therefore, decisions should only be made on a higher level if the lower level is not able to, or the consequences would impact the higher level [79]. Due to the decentralized character of the low-carbon transformation, the federal states have a great opportunity to influence the implementation. In general, all states have adopted own climate targets, which differ greatly in their ambitions. Geographical circumstances, the structure of the local economy, and the respective state governments are important factors influencing this. While on the one side, a state-driven approach can lead to more fitting and localized solutions (Biomass is mostly promoted in rural areas, observable in the CSU-governed state Bavaria [80]), on the other side however, state governments tend to concentrate more on their own voters which might lead to decisions made by the "not in my backyard" (NIMBY)-principle [81]. A prime example is the so-called H10 regulation in Bavaria, which requires that the distance between wind power plants and settlements must be ten times higher than the total height of the windmills [82]. This halves the effective area for wind power plants [83]. The phenomenon of federal governments being tempted to support local interests rather than the "greater" plan of nationwide goals is also visible in the different resorts of the government (See also Section 1.1): In §1 of the Energy Industry Act (EnWG), the objective to provide a safe, low-cost, consumer-friendly, efficient, and environmentally compatible energy system was announced [32]. This set of objectives illustrates the basic conflict potential between the Ministry of the Environment, Nature Conservation, and Nuclear Safety (BMU) and the Ministry for Economic Affairs and Energy (BMWi) [84]—a confrontation of environment against economy [85]. The focus of the BMWi concerning decarbonization is set on using the energy transformation as a "success story for Germany" [86]. For this purpose, the ministry created a ten point agenda to merge loose initiatives into a structured energy roadmap in 2014 [87]. Furthermore, the BMWi integrated the energy department so that it has the overall control over most of the energy reforms within Germany's policy, such as the EEG or the EnWG [88]. This ensemble should combine the economic and environmental responsibility into one ministry to ensure a more efficient problem-solving [89]. The BMU, on the other hand, operates in the field of frugal handling with resources and the preservation of habitat, for instance in the Emission Control Act. Thus, this remit positions the BMU on the side of advocates for environment and climate protection and initiatives [90]. In general, the German government is influenced by a range of different entities and serves as a hub for different interest groups. While there are top-down targets given by international agreements or EU-wide guidelines, there are also influences through established industry and demands by the public that need to be brought in line. Within the political system of Germany, the separation of power and the federal system leads to a discourse between many different departments which are entangled in multi-level governance. The discrepancy between pro-environment interests and pro-economic interests of the ministries can be transferred onto the economy itself: most of the economic spectrum can be divided into two camps. Those industries that tend to appear as "polluters" or "emitters" are more in favor of a slow transformation and no regulations, and those industries that benefit from the energy transformation are clear proponents of stronger incentives and clear government targets [90].

Influencing policy is usually done through lobbying by industry associations. Here, it can be clearly observed that associations tied to large and heavy industry, such as the Federation of German Industries (BDI) (The so-called Federation of German Industries (BDI) has 100,000 members with a total of 8 million employees: https://english.bdi.eu/bdi/about-us/#/article/news/the-federation-of-german-industries-bdi/), have an influence on draft laws. For instance, the BDI was working on an exemption from the EEG levy for energy-intensive companies in the amount of 5 billion Euros in 2014, designed in a way that does not violate European state aid law [89]. However, due to heterogeneity of its members, the BDI also supports a low carbon transformation. In contrast, branch associations with more homogenous members tend to have stricter positions: among others, the German Association of Energy and Water Industriess (BDEW) and the German Association of the Automotive Industry (VDA), argue that a fast decarbonization would harm the industry due to higher energy prices and lower reliability, risk jobs due to changing production lines (Süddeutsche Zeitung. 2018. "Elektromobilität gefährdet 75,000 Jobs in der deutschen Autoindustrie." https://www.sueddeutsche.de/wirtschaft/studie-zu-e-autos-elektromobilitaet-gefaehrdet-jobs-in-der-deutschen-autoindustrie-1.4002449), and decrease attractiveness of Germany as an industrial standpoint. The argument that the transformation is endangering a multitude of jobs, especially in so-called structurally weak regions, is also supported by trade unions: the Labour Union for the Mining Chemical and Energy Industries (IGBCE) in particular is working side by side with the major energy suppliers for the continuation of lignite power generation, arguing that with a phase-put of coal, 20,000 directly and numerous indirectly affected jobs could be lost (Most of them in structurally weak (former industrially shaped) regions like the Lusatia (8500 workers) in former East Germany or the Rhineland (9903 workers). This number is repeatedly confirmed, it originates from DEBRIV (federal German association of all lignite producing companies and their affiliated organizations) (Statistik der Kohlenwirtschaft e.V. 2018) but could be a little lower in reality.).

On the other side, associations supporting the benefitting sectors like the German Renewable Energy Federation (BEE) argue that the transformation would provide numerous jobs and the renewable energies sector itself is already an important factor on public wealth and development. Among others, the Mechanical Engineering Industry Association (VDMA) is one of the largest associations in the engineering sector, and, unlike the BDI, represents the German medium-sized companies (VDMA. Maschinenbau in Zahl und Bild. 2018. https://www.vdma.org/documents/105628/20243678/MbauinZuB2018_1524470187749.pdf/14e4650e-bb39-37de-92f1-cf43902e05e5 Last accessed: 18 June 2018). Aligned with the general arguments of the benefitting sectors, the VDMA focuses on export possibilities and global competitiveness. According to the association, a policy regime of incentives (e.g., the expansion of the ETS) and clear regulations lead to innovation and investments in the areas of energy infrastructure and production, sector coupling, and transformation technologies [91]. Furthermore, there are several state-funded or private research institutes and think tanks, as well as environmental organizations which are rather supportive of the energy transformation and also have an influence on the public opinion. With the instrument of the so-called "right of collective action", environmental associations recognized by the Federal Environmental Agency [92] are able to make sure environmental directives are enforced. Most prominently, this tool is used by the Deutsche Umwelthilfe e.V. (DUH) to force cities to comply with emission values and driving bans.

At last, the public opinion plays a major role of the success of energy transformation: Unlike the industrial sector, the vast majority of people are supporting the transformation: Representative polls reveal a positive public agreement of up to 95% (AEE. 2017. "Repräsentative Umfrage: 95 Prozent der Deutschen wollen mehr Erneuerbare Energien." https://www.unendlich-viel-energie.de/akzeptanzumfrage2017.). However, some surveys record a negative tendency in the past years [93]. Especially on a municipal level—in areas where onshore wind turbines are installed—projects are confronted with criticism and skepticism that might lead to heavy protests and the foundation of a countermovement which could significantly hamper the energy transformation [94–97]. The motivation of energy transformation opponents goes beyond the NIMBY pattern which is often used to hastily explain countermovement [93,98]. NIMBY arguments (e.g., potential negative consequences for health or any decreasing value of the own property) are among the motives, but are accompanied by other concerns such as protection of the environment, aesthetic reasons concerning the landscape, or a general critique of the present energy policy.

Appendix B. Model Description

GENeSYS-MOD is a cost-optimizing linear program, focusing on long-term pathways for the different sectors of the energy system, specifically targeting emission constraints, the integration of renewables, and sector-coupling. The model minizes the objective function, which comprises total system costs (encompassing all costs occuring over the modeled time period) [14,71].

(Final) Energy demands are given exogenously for each modeled time slice, with the model computing the optimal flows of energy, and resulting needs for capacity additions and storages. Additional demands through sector-coupling are derived endogenously. Constraints, including energy balances (ensuring all demand is met), maximum capacity additions (e.g., to limit the usable potential of renewables), RES feed-in (e.g., to ensure grid stability), and emission budgets (given either yearly or as a total budget over the modeled horizon) are given to ensure proper functionality of the model and yield realistic results. Figure A1 shows a graphical representation of the functional units of GENeSYS-MOD, as well as additions and changes between model versions.

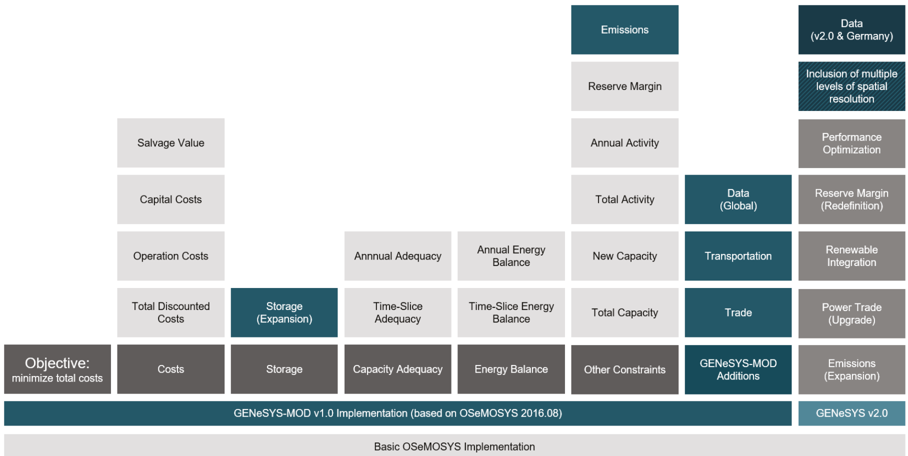

Figure A1. Model blocks of GENeSYS-MOD, including objective function, constraints, and version changes.

The model allows for investment into all technologies (Except when given fixed, predetermined phase-out dates, such as for nuclear power in Germany.) and acts purely economical when computing the resulting pathways (while staying true to the given constraints). It assumes the role of a social planner with perfect foresight, optimizing the total welfare through cost minimization. All fiscal units are handled in 2015 terms (with amounts in other years being discounted towards the base year). The effects of myopic/limited foresight, as well as the analysis of different discount rate models are planned for further reasearch and might yield even more insight in the possible developments of the energy system.

Fore more information on the mathematical side of the model, as well as all changes between model versions, please consult Howells et al. [71], Löffler et al. [14], and Burandt et al. [15].

Appendix C. Relevant Input Data

Appendix C.1. Technology Costs

Table A1. Capital Costs of main electricity generating technologies in M€/GW.

	2015	2020	2025	2030	2035	2040	2045	2050
Utility PV	1000	580	466	390	337	300	270	246
Onshore Wind	1250	1150	1060	1000	965	940	915	900
Offshore Wind Deep								
Offshore Wind Shallow								
Offshore Wind Transitional	3500	2637	2200	1936	1800	1710	1642	1592
Geothermal	5250	4970	4720	4470	4245	4020	3815	3610
Coal-Fired Thermal Plant	1600	1600	1600	1600	1600	1600	1600	1600
Gas-Fired Thermal Plant	650	636	621	607	593	579	564	550
Oil-Fired Thermal Plant	650	627	604	581	559	536	513	490
Coal-Fired CHP	2030	2030	2030	2030	2030	2030	2030	2030
Gas-Fired CHP	977	977	977	977	977	977	977	977

Appendix C.2. Fuel Costs

Table A2. Fossil Fuel Cost Assumptions in M€/PJ.

		2015	2020	2025	2030	2035	2040	2045	2050
Oil [Import]	EI/GD	7.12	10.18	11.02	11.86	11.37	10.88	10.39	9.91
	SOTF	7.12	10.91	12.60	14.40	14.62	14.77	14.85	14.86
Coal [Import]	EI/GD	1.52	1.54	1.53	1.52	1.44	1.36	1.28	1.20
	SOTF	1.52	1.65	1.75	1.84	1.85	1.84	1.82	1.80
Fossil Gas [Import]	EI/GD	6.63	6.54	7.72	8.91	9.15	9.38	9.62	9.86
	SOTF	6.63	7.01	8.83	10.82	11.76	12.73	13.74	14.79
Lignite [Domestic]	EI/GD	1.09	1.11	1.14	1.17	1.13	0.99	0.72	0.42
	SOTF	1.09	1.19	1.39	1.73	2.17	2.56	2.68	2.33

Appendix C.3. Renewable Potentials

Table A3. Renewable Potentials in GW installed capacity per region.

	Onshore Wind	Offshore Wind	Utility PV
DE_BB [Brandenburg]	13	0	19.2
DE_BE [Berlin]	0.3	0	0.6
DE_BW [Baden-Württemberg]	23	0	23.1
DE_BY [Bavaria]	41	0	45.6
DE_HB [Bremen]	0.2	0	0.3
DE_HE [Hesse]	14	0	13.6
DE_HH [Hamburg]	0.3	0	0.5
DE_MV [Mecklenburg-Western Pomerania]	11	6.6	15
DE_NI [Lower Saxony]	26	49.8	30.8
DE_NRW [North Rhine-Westphalia]	20	0	22
DE_RP [Rhineland-Palatinate]	12	0	12.8
DE_SH [Schleswig-Holstein]	9	28.6	10.2
DE_SL [Saarland]	2.4	0	1.7
DE_SN [Saxony]	10	0	11.9
DE_ST [Saxony-Anhalt]	7.4	0	13.2
DE_TH [Thuringia]	7.5	0	10.5

Appendix D. Additional Result Graphs

Appendix D.1. Transport

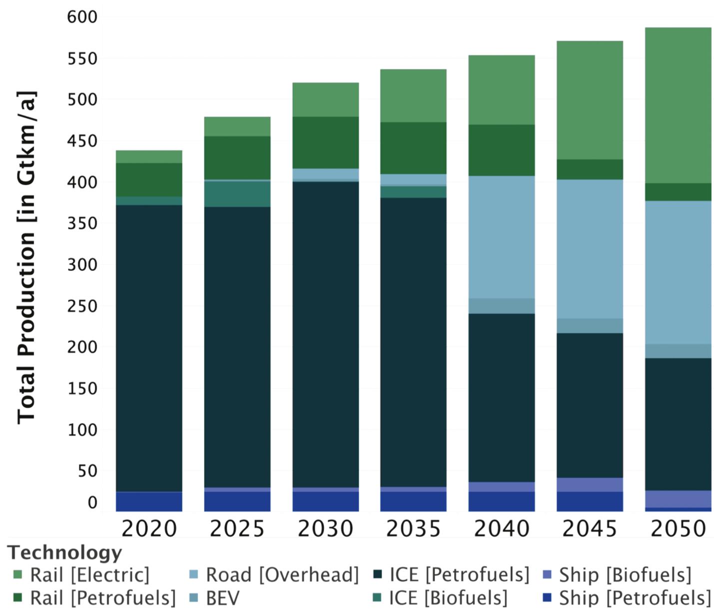

Figure A2. Development of freight transportation for the Green Democracy scenario.

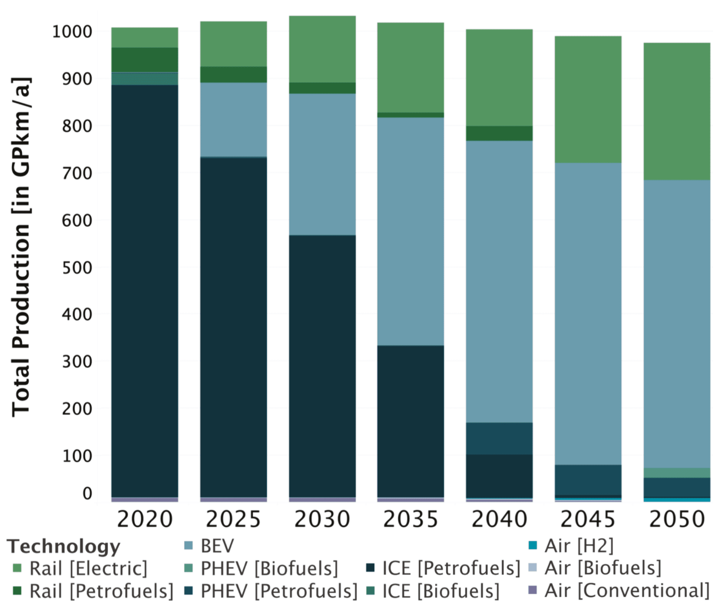

Figure A3. Development of passenger transportation for the Green Democracy scenario.

Appendix D.2. Regional Power Development for the EI and SOTF Scenarios

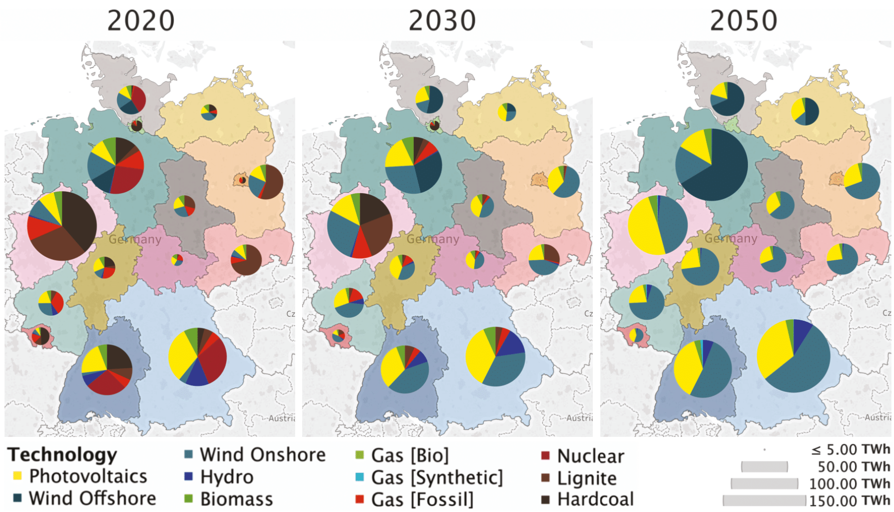

Figure A4. Regional development of Germany's power production for the scenario.

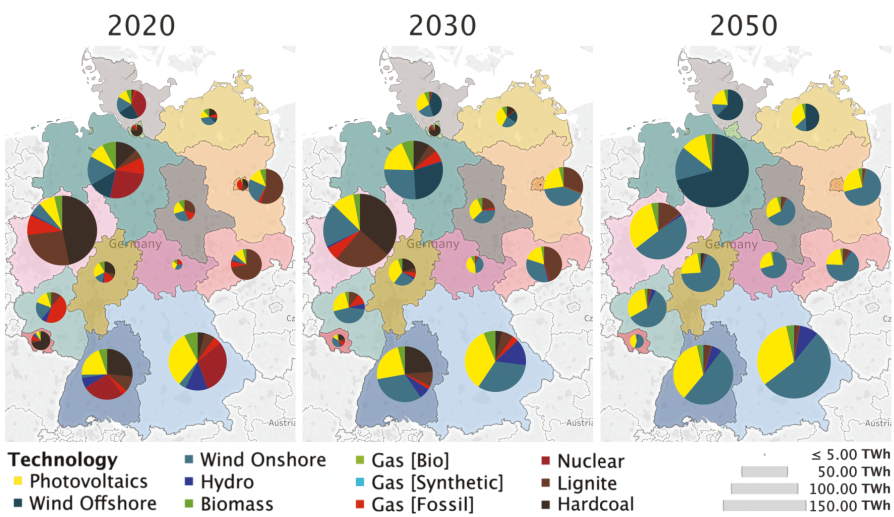

Figure A5. Regional development of Germany's power production for the Survival of the Fittest scenario.

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Transitioning Island Energy Systems—Local Conditions, Development Phases, and Renewable Energy Integration

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Abstract: Islands typically have sensitive energy systems depending on natural surroundings, but innovative technologies and the exploitation of renewable energy (RE) sources present opportunities like self-sufficiency, but also challenges, such as grid instability. Samsø, Orkney, and Madeira are in the transition to increase the RE share towards 100%—however, this is addressed in different ways depending on the local conditions and current development phases in the transition. Scenarios focusing on the short-term introduction of new technologies in the energy systems are presented, where the electricity sector is coupled with the other energy sectors. Here, both smart grid and sector-integrating solutions form an important part in the next 5–15 years. The scenarios are analyzed using the modeling tool EnergyPLAN, enabling a comparison of today's reference scenarios with 2030 scenarios of higher RE share. By including three islands across Europe, different locations, development stages, and interconnection levels are analyzed. The analyses suggest that the various smart grid solutions play an important part in the transition; however, local conditions, sector integration, and balancing technologies even more so. Overall, the suggestions complement each other and pave the way to reach 100% RE integration for both islands and, potentially, other similar regions.

Keywords: island energy system transition; 100% RE pathways; RE integration; smart grid technologies; energy sector integration; smart energy system; Samsø; Orkney; Madeira

1. Introduction on RE Integration on Islands

Islands' energy systems are like most other energy systems aiming to utilize renewable energy (RE) to supply their demands. However, they are under more pressure due to their inherent isolation and higher dependence on their natural surroundings, including conditions affecting possible RE utilization. The European Union (EU) has the general ambition to increase the use of RE in the near future [1], and various studies suggest how to increase the use up to 100% through sector integration [2,3].

The EU specifically targets "clean energy for EU islands" to support this transition [4]. Islands are to follow the same trend despite their limitations, but they can also benefit much more from local utilization of local resources to increase self-sufficiency. Research has already touched on the present and potential future, but also the limits of RE on islands as it can be difficult to increase the RE share without proper step-by-step integration and balancing.

A review of RE utilization on islands by Kuang et al. [5] presented various cases of current developments, as well as suggested strategies to improve the utilization further. While solar, wind, hydro, and other technologies have been implemented to various extents, the sole exploitation of these potentials does not seem enough to reach high levels of self-sufficiency. Instead, further exploration of storages, demand side management, and micro and smart grids are mentioned to increase the RE shares further.

Praene et al. [6] presented the example of Reunion, where the self-sufficiency rate with RE has been decreasing over a period of years due to increasing energy demands. While hydropower has been a technology early and substantially explored on Reunion, by 1982, the limited potentials were almost fully exploited and unable to match the growing demands, resulting in a decreasing RE share.

While some islands in the Pacific are still struggling with small-scale RE projects hitting barriers of financial, institutional, environmental, and skill basis, the willingness for these was shown by Weir [7], but the information on how best to approach this on islands is yet to be evaluated. Thushara et al. [8] presented an example of an island (Sri Lanka) without grid connection or fuel reserves on the verge of finding the right future power generation, showing limits and conflicts to a full renewable supply.

Ioannidis et al. argued that islands are forced to invest in RE to avoid dependence on fossil fuel imports, energy scarcity, and other uncertainties [9]. These investments might happen uncontrolled, resulting in imbalanced energy systems. Meschede et al. [10] applied the EnergyPLAN model to the island of La Gomera and, based on analyses of different supply time series, the authors' results show advantages of diversified energy supply for this case study.

New technological solutions are currently being tested and studied on islands in this regard. Dorotić et al. presented a novel approach of relying on vehicle-to-grid (V2G) in combination with wind and photovoltaic (PV) power for the Croatian island of Korčula [11]. Meschede et al. discussed the necessary determination of appropriate smart energy system design for various-sized Philippine islands, including solutions around hybrid and storage technologies, besides connection to larger grids [12].

Rakopoulos et al. [13] mentioned the trend towards smart grids in the development of island energy systems. Colmenar-Santos et al. [14] discussed the development of RE for islands from a grid regulation perspective. Besides the requirement to align regulatory plans between islands and the rest of the country, the continental part of the country can benefit from using islands as testbeds, as they often present the same energy system aspects. To test large RE shares, the consideration of smart grid, storage, and electric vehicle (EV) implementation is suggested. For this, the specific locations and characteristics, as well as the involvement of the people of the islands, should be included. With the advance of information and communication technologies, grids can transition to smart grids that allow the use of monitoring, analysis, and control within its supply chain with the aim to improve the energy system. Rakopoulos et al. [13] further defined the framework for the development of island smart grids under the prospect of this technology becoming a priority for the European Commission. They are to help decrease carbon footprint and costs of energy by improved automation, distribution, and reduction of peaks in the grid.

Demonstration and evaluation of selected smart grid and sector integration technologies is addressed in the 2017–2021 project SMILE (Smart Island Energy systems) [15]. This focuses on the new phase in the RE transition with smart technologies to reach 100% RE shares on three demonstration islands: Samsø, Orkney, and Madeira. These islands are all investigating ways of increasing the RE share in their energy system, though local conditions and potentials differ widely, as well as their level of progress in this transition. While Samsø has been undergoing a decade-long transition from nearly zero to a high RE share after winning a competition of being Denmark's officially designated RE island [16], it has, however, not solved the full energy system integration. The Orkney Isles are characterized by a large number of wind turbines and offshore energy production testing facilities, but suffer from fuel poverty and curtailment [17]. Madeira lies far off the European continent and stands out in European terms with great solar potential, while having to balance their energy system and grid stability autonomously [18]. These islands are therefore good case studies with challenges, as well as potentials, for the evaluation of RE integration in the transition to 100% RE.

Scope and Structure

While some islands still largely depend on fossil fuels and struggle to introduce RE, other islands already exploit most of their RE potential, but also face problems related to this. The literature study shows that growing energy demands, various barriers, and imbalances require more research and exploration of solutions. While new technologies, such as V2G, hybrid and storage options, and other smart grid solutions, have been introduced or studied, they have mainly been considered individually and in limited contexts. In addition, they have not been studied as part of a holistic island energy system transition process considering and comparing local conditions' impacts.

With trends and plans aiming at full self-sufficiency in the near future, further transition is suggested with various new technologies, yet it is not clear how the smartening of the grid and wider energy systems with these could be addressed, realized, and aligned on islands. Hence, it can be said that a new phase in the transition towards 100% RE is emerging. In contrast to previous publications, this paper presents an alternative approach to explore the transition towards higher shares of RE by presenting a three-phase characterization and important criteria to help the transition within. The study and presentation of the case studies' complex energy systems and the alignment, as well as distinction of the transition of three similar yet individual islands, further address the research gap.

The work presented here should be seen as the first technical explorative step in a required energy system transition, where the explorative step unveils the technical possibilities. This is not limited by local economic, social, or political aspects. Subsequent steps assess what is required to implement the technical solutions, focusing on social acceptance and business and socio-economic costs—and finally, possibly the adaption of policies, regulations and business economic framework conditions to advance technically and socio-economically favorable solutions. These later steps, however, are beyond the scope of the work presented in this article.

Section 2 presents the scenario simulation tool EnergyPLAN, along with scenario data acquisition and scenario design methods. They are used to evaluate the case study islands as presented in Section 3, specifically addressing the steps from today's to 2030 energy systems. This is adopted from the framework of the EU-founded research project SMILE, resulting in Samsø, Orkney, and Madeira as cases [15]. A final overview of the case studies is added and discussed in relation to the general ongoing transition progress in Section 4, before the conclusions are presented.

2. Materials and Methods

This section presents the EnergyPLAN model applied in the scenario simulations, as well as the data gathering and verification methodology applied. Finally, the scenario design approach is detailed.

2.1. EnergyPLAN

The EnergyPLAN model can simulate the electricity, heating, cooling, industry, and transport sectors of an energy system on an hourly basis over a one-year time horizon, and can be used on various geographic levels and sizes of energy systems. Hence, it can be adjusted to specific locations and years by applying the respective data, such as projections to 2030. It simulates the mix of technologies in the whole system by identifying and exploiting synergies across the sectors. It is able to model fluctuating energy sources, and simulates their effects on the rest of the energy system. Depending on the inputs, such as technology capacities, efficiencies, and costs, as well as the demand and supply of the investigated case, various simulations become possible [19,20].

EnergyPLAN's simulation strategy is either technical or economic. While the economic strategy focuses on the most economically feasible operation of the energy production units based on exogenously given market data, the technical strategy focuses on primary energy supply (PES) and hourly system balance. For this article, the technical strategy is chosen as the basis for comparisons of technical possibilities in the transitions. As Sorknæs et al. [21] and Djørup et al. [22] point out, RE influences market prices, thus for 100% RE systems, existing market data (as used in EnergyPLAN) cannot be used for simulations, whereas technical simulations show the technical possibilities. Nonetheless, the socio-economic assessment includes technology costs without taxes or subsidies and CO_2 costs, assuming to bring socio-economic perspective to the otherwise technical simulation. Any variation between the business economic and socio-economic cost will be comparable between different technologies.

The reference models are adjusted to fit to a reference year for which sufficient data is available. These are compared to future scenarios that include other technologies or changes in demand and supply profiles, according to the suggestions for the case studies of the transition towards 100% RE. Especially relevant for this study, EnergyPLAN may simulate island mode, allowing for an analysis irrespective of interconnections. Any export or import is therefore not evaluated further in terms of fuel consumption or related emissions avoided through export and caused by import.

The resulting relevant effects in this study include RE shares of PES and electricity production, import/export balance, CO_2 emissions, and annual socio-economic costs for each scenario investigated. The scenarios presented include the reference scenarios, which are created through research and in cooperation with the SMILE partners, as well as the future scenarios, which focus on high RE shares in relation to local conditions.

EnergyPLAN has been used in a high number of articles [23,24], including island studies on Korčula [11], Samsø [25–27], Gran Canaria [28], La Gomera [10], Flores [29], and Bornholm [30], to name a few.

2.2. Data Gathering and Verification

The modeling of island energy systems entails the study of energy supply, conversion, and consumption. The unique characteristics of each of the studied island systems in this article are established in cooperation with SMILE partners of the respective islands. This includes the consideration of data from annual energy accounts and reports, as well as applicable literature for a reference year to build a reference model upon [31,32].

References are based on data of existing technologies with capacities, efficiencies, and costs. Furthermore, hourly distribution profiles are gathered and added to the models for the simulation of production of renewable electricity and heat, as well as for the consumption of electricity, heat, and transport. The hourly production of electricity is based on local inputs [33] or numerical models [34], [35]. The one for hot water with solar collectors is simulated with the help of energyPRO [36], with the temperature and radiation data of the selected reference year and an inclination angle typical for each region [37]. energyPRO is a simulation model created to make detailed business–economic simulations of particularly district heating plants (see [38] for a more thorough description); however, here, it is only applied due to its facility to model solar collectors. Consumption data results from local measurements or studies of households [39] and weather data.

The hourly distributions are applied in the model according to the annual values for each of the production and consumption units to represent the energy systems as close to reality as possible. For verification, EnergyPLAN is run and the annual modeled values compared to the actual ones—for example, the remaining required production from conventional power plants. If needed, alignments and corrections are made in the models, in coordination with the partners, to improve their representation of the reference energy systems [31].

2.3. Transition Scenario Design

After establishing and verifying the reference scenarios, a classification of the respective energy systems is made, categorizing them into the specific RE integration phase, as illustrated in Table 1. These phases are typical for systems going from fossil reliance to RE integration and finally complete independence from fossils as defined by Lund [40]. Energy systems with up to 20% of RE are thereby grouped in the RE Introduction phase, characterized by no to little RE integration problems, where RE would be able to directly reduce fossil fuel consumption. The next phase is large-scale RE integration, with RE influencing and interfering with the existing system(s), requiring hourly analyses due to the time-dependence intermittency of RE. This second phase might already require balancing technologies as the influence from RE on the system becomes complex. The final phase of the transition to 100%

RE systems requires the integration and comparison of various technologies supporting stability depending on the local conditions.

Table 1. The phases of renewable energy (RE) integration in the transition to 100% RE to classify energy systems and respective technical requirements, based on [40].

Phases	RE Introduction	Large-Scale RE Integration	Towards 100% RE
Example energy system	Small share of RE, no problem integrating, direct fuel reduction	Existing large share of RE, system influence and interference time-dependent due to large share of intermittent RE	Transformation into 100% RE-based system, complex comparison of various technologies requiring balance, sector integration, optimized biomass utilization

The next step in a transition depends on already existing RE utilization, local demands, and further potentials, but also on the availability of technologies. These might include various RE technologies, power-to-heat, power-to-gas, power-to-transport, thermal energy storage (TES), battery electricity energy storage (BESS), and fuel storages, as well as demand side management and algorithmic approaches—including various smart grid solutions. With EnergyPLAN, it is possible to define and model the respective technologies depending on the local data gathered. For example, the potential addition of electric transport can be included and defined with various charging and V2G options that are most suitable for the individual case.

In this paper, a short-term analysis of the transition of three island energy systems is made. Therefore, the resulting scenarios are created under consideration of the current energy system, as well as the planned actions in the upcoming 5–15 years. With this approach, certain possible changes are neglected, such as potential changes in weather conditions, demography, and unforeseeable changes in production or consumption. Related rebound effects are thereby also not studied, and neglected in the simulation. In relation to this, the temporal distribution profiles for heating and electricity are kept the same, unless specifically studied and changed due to a certain technical modification.

The scenarios consider the following: Case-specific savings potentials, case-specific RE availability, and case-specific potential energy conversion shifts. Furthermore, as an integrated part, they consider the extent to which the systems should or could rely on interconnection to the mainland or be self-sufficient. Reducing or limiting the amount of import and export is therefore aimed not to rely on the balancing capability of surrounding energy systems. Instead, local products should be used for the local systems to the largest sustainable extent possible, including using otherwise exported or curtailed electricity. For this, the integration and balancing of energy sectors becomes important.

As introduced, sector integration—partly through smart grid solutions—is key to the transition towards high RE shares in the total PES [40], and is therefore included in the scenario design, which goes beyond the idea of SMILE. In line with the RE aspect, fossil fuels, but also biomass, should be limited to a sustainable level, respectively. This goes hand in hand with the target of reducing CO_2 emissions, and aligns with the EU climate targets [1]. While costs play a secondary role in the scenario making, its reduction should nonetheless also be aimed to ease implementation. Finally, the aim should be to minimize losses in the various sectors and throughout the entire energy system. This illustrates the detailed requirements for the transition of these islands towards large-scale and eventually 100% RE integration.

The scenarios are made in parallel and involve similar tasks for the different geographical areas—though different starting points and RE options result in scenarios of varying complexity and composition. Adopting this methodology for the demonstration islands of the SMILE project somewhat predefines the scenarios, yet they are further dependent on the local conditions and demands. Finally, this presents a variety of suggestions on smart grid solutions and, though being tested for three specific island cases, it can give insight into further planning approaches for most energy systems. The SMILE islands and their approaches to transit towards higher RE shares are presented in the following.

3. Case Study and Island Scenarios

To evaluate RE potentials on Samsø, Orkney, and Madera, scenarios are developed which include (1) the SMILE smart grid demonstrations, (2) a potentially larger deployment of them if suitable, and (3) in general a shift from energy systems relying on fossil fuels to energy systems relying highly on RE by 2030. The focus of the scenarios is the approach of the ongoing transition to ensure a balanced energy system with increased RE share, which may look very different for each island.

With the definition of the three phases in Table 1, the islands are classified in different stages as seen in Table 2. Samsø is furthest ahead in terms of self-sufficiency and supply through RE. With a reference RE share of almost 60% in 2015, Samsø is classified as being in the second phase of RE integration, aiming for the third phase: 100% RE. It can be said that Samsø achieved the first phase of RE introduction already in 2007. This shapes the evaluation of technologies and creation of the future scenario.

Table 2. The SMILE islands and respective required technologies for the varying phases in the transition to 100% RE (shares are current references and projected targets with respective year).

Phases	RE Introduction	Large-Scale RE Integration	Towards 100% RE
Samsø (Large-scale to 100% RE)	Wind turbines, PV, biomass and solar district heating, individual heating with biomass and electricity **>25% RE share** (2007)	More PV, wind turbines, and individual heating with biomass, electric, and solar thermal, savings **60% RE share** (2015)	SMILE: BESS, PV, heat pump Short-term: Update district heating, Biogas plant, EV, further RE capacity, heat pumps **~100% RE share** (2030)
Orkney (Introduction to large-scale RE)	Wind turbines, electric heating **18% RE share** (2014)	SMILE: BESS, TES, heat pumps, EV Short-term: More PV, wind turbines, wave and tidal capacity, savings, more heat pumps and TES, hydrogen, electrolyzer **~50% RE share** (2030)	Discussion to include in longer term: District heating (biomass or electric), TES, heat pumps, savings, synthetic fuels, EV **~100% RE share** (?)
Madeira (Introduction to large-scale RE)	Hydro, wind, PV, autonomy **11% RE share** (2014)	SMILE: PV, BESS, EV Short-term: More PV, wind turbines, hydro and pump storages, geothermal **~50% RE share** (2030)	Discussion to include in longer term: District cooling, solar thermal and TES, BESS, EV, savings **~100% RE share** (?)
	Short-term (2014/2015–2030)	2030 scenarios Large-scale—100% RE	Longer-term (2030–?)

Orkney and Madeira have RE shares in the reference year 2014 of 18% and 11%, respectively, classifying them as still being in the RE introduction phase. Consequently, the next step is to reach large-scale RE integration, before aiming at the 100% target. This is characterized by the expansion of RE, such as wind and PV capacity, instead of a focus on integration and balancing, as would be the case afterwards. However, due to the long-term goal of reaching higher RE shares, some technologies, mostly defined through SMILE, already include sector-integrating and balancing options. The technologies considered for these steps are presented in the overview in Table 2, showing that different phases are reached in the addressed 2030 scenarios.

Based on the methodology, the EnergyPLAN models of Samsø, Orkney, and Madeira are introduced in the following, including the 2014/2015 references and the 2030 scenarios with the incorporation of transition suggestions. The corresponding data of all scenarios are shown in the overview Section 4.

3.1. Samsø, Denmark

Samsø is located off the east coast of the Danish mainland. It presents typical characteristics of Danish municipalities regarding energy supply, but also specifics related to being an exemplary RE island [41]. Being part of Denmark and its ambitious targets for sustainability, district heating has become an important cornerstone to supply clusters of heat demands. The employment of wind power is another important aspect, which makes up a major characteristic of Samsø's reference and future energy system. With most data available for 2015, this year is used in the reference scenario.

3.1.1. Samsø Today

Today, Samsø's population is at around 3700 inhabitants, and their electricity supply is mainly covered by both onshore and offshore wind power, as well as some PV capacity. With fixed capacities and temporal distributions, yearly productions are fixed in the model. These are aligned with known yearly reference productions in EnergyPLAN. Next to solar and wind resources producing mainly electricity, but also some hot water from solar panels, Samsø relies on the electricity imported through a 40 MW connection to the mainland of Denmark. This connection is mainly used for the export of surplus wind power, as well as for a limited amount of hours for import of electricity. There is no fuel-based power generation on Samsø [42–45].

Heat is supplied from four district heating plants running on woodchips, straw, and solar heat, or by individual heating devices using further biomass, oil, solar collectors, or electricity [44]. The transport sector is 99% fossil fuel-dependent, with only a small number of EVs. The main consumers—ferries connecting Samsø to Danish mainland—run mostly on oil and some natural gas.

With a high share of wind power, as well as an extensive exploration of biomass, the RE share of the PES reached 60% in the reference year 2014. Especially the transport sector, and some of the individually-heated buildings, still require fossil fuels. When it comes to electricity needed on Samsø, 94% is produced by wind and PV and the remaining 6% is imported.

Samsø is the smallest of the three case study islands, with the highest RE share and the comparably lowest CO_2 emissions (28.5 kt). The biomass heating share is 69% in the reference system with 35% of the heat supplied through district heating, but still 18% from oil boilers. The electric and solar heating shares are at 11% and 2%, respectively, and the electric transport share at 1%—hence having room for improvement, especially with 78% of the local RE electricity being exported.

3.1.2. Transition of Samsø

In SMILE, Samsø therefore addresses the possibility of employing more local electricity on the island. For this, some further PV capacity is installed, but also unused existing capacity can be better integrated with smart controls and a BESS. This is tested in the scope of Ballen Marina, which is used by both locals and tourists, hence an integrated part of the energy system. Here, PV power is planned to be smartly used and stored to decrease the dependency on imports, which in combination with heat pumps further contributes to this local test scope. If successful, this idea could be replicated in the other marinas on Samsø and elsewhere [46].

The impact of the Ballen demonstration can be integrated in the EnergyPLAN reference model by adapting the total remaining electricity demand and by adding the excess PV production as supply available for other uses. The expected outcome is a reduction of imports by shaving the marina's peaks, increasing the usage of fluctuating renewable electricity locally, and thereby decreasing the island's dependency on others. Looking further ahead, the improved utilization of local RE becomes important when more electric heating and EVs are introduced.

The smart controlling of heat production via heat pumps further opens up the possibility to reduce the use of biomass boilers. While biomass heating is renewable, it is not an optimal use of a storage fuel, and the biomass could alternatively enable the production of biofuel for other uses—e.g., for running one of the ferries such as the natural gas-run Prinsesse Isabella. The overall goal of Samsø is therefore the reduction of imports by using more otherwise exported electricity, reducing further biomass consumption in the heating sector and freeing it for the transport sector. Thereby, Samsø is currently in transition phase two, with an already large RE share and aiming for 100% RE.

Further steps besides the SMILE ideas for the further transition to 100% RE include local biogas production and electricity for transport, improving the district heating plants, as well as an increase in RE capacity. By 2030, a biogas plant is to be realized, contributing to reducing the fossil fuel demand of the ferries and potentially also to the road transport. In addition, the road transport is considered to be further electrified, with focus on passenger vehicles, as recommended by Mathiesen et al. [2] and Connolly et al. [47]. With the implementation of EVs, some of the excess electricity is utilized, while it also increases the island's electricity demand. Overall, the higher efficiency of electric compared to internal combustion vehicles decreases the total energy demand [48].

District heating plants are considered retrofitted with heat pumps due to the availability of excess electricity and the scarcity of biomass resources. By keeping the existing boilers for peaks, heat pump support, and backup, the heat pumps can be operated to run entirely on excess electricity from RE. This is furthermore supported by additional TES next to the existing ones. Depending on the available excess RE electricity on Samsø, the amount of heat produced from heat pumps depends on the increase of electricity consumption in the other sectors. Hence, if the number of EVs increases, the heat pump production might be reduced to avoid increasing electricity imports.

Furthermore, additional wind and PV capacity under the condition of limiting the critical excess electricity production is evaluated. Large RE capacities of one technology can result in large amounts of excess electricity in certain (e.g., windy) hours, so an increase of PV capacity with a total of 10 MW is suggested. Electricity from PV is shown to be better integrable in the energy system and potentially easier realized regarding space demand and potential opposition in the population [49].

To reduce the remaining fossil fuel use, heat pumps should replace the individual oil boilers, after which any remaining fossil fuel consumption is found in the transport sector. One option to lower this and to integrate the still high RE export further is through electrolyzers and hydrogen production as fuel replacement. In total, with the short-term steps in the transition of Samsø, the RE share reaches 85% and the CO_2 emissions are below 10 kt per year compared to the reference model with 59.5% and 28.5 kt.

3.1.3. Samsø's Future

The concluding Figure 1 presents data for demand and supply before and after the transition steps (see tables in Section 4). Most notably, the connections between sectors increase as sector integration and balance options are pointed out as important parts of the transition. However, a small share of the now increased electricity demand needs to be imported due to the inflexibility of the modeled demand. Despite an overall electricity demand increase of 64%, the RE share of the electricity consumption is increased by 2% point to 96% from the 2015 to the 2030 model (cf., Table 6).

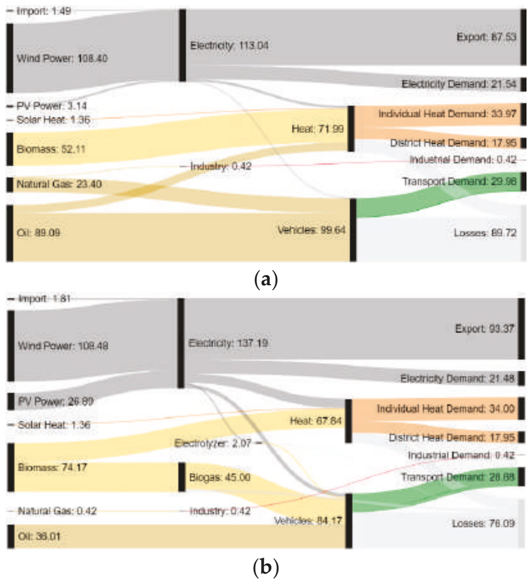


Figure 1. Sankey diagrams of energy flows in GWh for Samsø for 2015 (**a**) and 2030 (**b**) [32].

To replace the remaining fossil fuels, alternative fuels are needed, which can also further reduce system losses. An extension of the biogas plant or a replacement of remaining fuels with electro- or biofuels could be considered. Next to the further increase of the RE capacity, more efficient heating and transport options are still required for a full transition to a 100% RE island. Additionally, smart controlling and management of various demands could support the transition, so further exploration and integration of solutions such as those presented in SMILE is recommended.

3.2. Orkney, United Kingdom

The 70 islands in the Orkney archipelago, out of which 20 are inhabited, lie to the north of the Scottish mainland. The Orkney Isles are characterized by a mild climate with open waters on three sides, which offers good opportunities for wind and ocean energy exploitation. Within the United Kingdom and over the last 30 years, Orkney has been a frontrunner in the development of RE technologies [50]. With an Energy Audit made for 2014, this is chosen as the reference year.

3.2.1. Orkney Today

Orkney represents the medium size case study island, with around 22,000 inhabitants, and lies between Samsø and Madeira in terms of RE share and CO_2 emissions (186 kt). Wind and some PV power supply the majority of the islands' electricity demand in the reference year: Only 7% of the demand is imported and 27% is supplied by the local power plant. A large part of the heat is still relying on oil, as is the industry and transport sector, despite the relatively high amount of EVs compared to other regions in the UK or Europe; its share is estimated at only around 0.1% of the total transportation demand (0.2% of the road transport).

Utility-scale turbines and around 500 domestic-scale turbines [51] almost reach the annual electricity demand of Orkney in the reference year, but due to the fluctuation of its production, other electricity needs to be provided [52]. Next to the fluctuation, intra-island grid bottlenecks are a problem, causing high degrees of curtailment and a limit of firm connections from turbines to the grid. For the remaining electricity demand [53], a small share of PV systems and two subsea cables supply some of the additionally required electricity [50,52]. Since the wave and tidal power facilities are still considered test facilities and not in commercial operation, they are not considered in the reference system.

Additionally, fuels are used for electricity production through a local thermal power plant. The total amount of fuel for electricity production results from the EnergyPLAN model, which simulates the production of electricity from fossil fuels when not enough wind and PV power is produced. Therefore, the amount of gas to supply the energy system of Orkney is made up of a large share for power production, as well as gas-fueled heating systems [54,55]. Solar radiation is also used to produce heat through around 20 solar thermal collectors [56,57].

While the electricity sector is mainly supplied by locally produced electricity, the heating sector still relies a lot on fossil fuels, even though Orkney has an electric heating share above the average [54,58]. Together with the fuels needed in the transport and industrial sector, this results in the overall RE share of 18%. All data of the reference as well as the future model are presented in Section 4.

3.2.2. Transition of Orkney

In the reference model of Orkney, the CO_2 emissions are at a similar amount per capita as on Samsø. The biomass share, however, is much smaller, with 1% of the modeled heat sector for 2014, while the electric heating share is at 44%, resulting in a high share of fuel poverty in the area [58]. With a current export share of 32% of the local RE production and no district heating grid, there is room for improvement.

To address the option of more efficient heating, in combination with otherwise curtailed or exported electricity, the SMILE demonstration project on Orkney focuses on new domestic electric heaters with storage, as well as on including electric transport through more EV charging stations. Both options include smart planning and operation, meaning taking into account the temporality of excess RE production and the potential demands.

By integrating RE in a smarter way, the local energy can be used locally and benefit both the heating and the transport sector. Furthermore, it can reduce imports and production at the power plant if demands can be shifted to hours of excess production. This reduces the islands' fuel use and CO_2 emissions, as well as reduced electricity exchange and curtailment. An increase in self-sufficiency is the overall goal and is presented in the following through a technical approach, including the SMILE demonstration.

The resulting impact on CO_2 emissions can be connected to the reduction in heating oils, while the heat pumps increase the total electricity demand, causing a reduction in exported electricity. Adding more EVs, even though smart-charged, adds to this reduction of export and CO_2 because of the shift from transport oils to electricity. Furthermore, an increase of import happens due to inevitable temporal mismatches between RE production and charging.

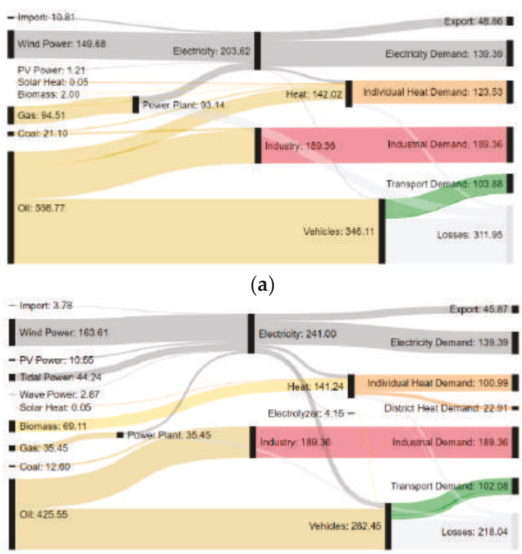
Besides the SMILE approaches of heat and transport sector, some other changes that are taking place on Orkney need to be incorporated and matched with the transition to achieve higher RE shares. One such change is the addition of marine energy exploitation, including wave and tidal power, as well as hydrogen and electrolyzers, which have shown promising test results for future exploration [50,59,60]. Not all included technologies have an appropriate technology readiness level today, but there is an ongoing technology development in the field. Thus, for future scenarios, particularly in islands setting, the technologies must be considered.

Additionally, with a focus on banning the sale of diesel and petrol cars by 2032 in Scotland [61], Orkney is on the way to increasing the use of EVs to a suggested maximum around the year 2030 [2,47]. Therefore, 80% of the road transport (all passenger vehicles) is modeled to be reliant on EVs with V2G balancing the electricity import and export to the highest extent possible. This is modeled by allowing the EVs to supply the grid via a standard 10 kW capacity per car of battery to grid connection [48].

As part of the further transition and to improve the heating sector of the island, district heating is proposed to be implemented in the largest town on Orkney, namely Kirkwall, as previous studies [62,63] suggest large heat densities there. With the selection of this central heat demand, 33% of the current heat demand on Orkney could be covered with district heating. Due to the still large amounts of excess electricity, a heat pump is to supply this district heating grid, as well as a biomass boiler as a supplement and back-up to avoid increased electricity imports. In addition, the individual heating sector is to develop further towards renewable heat: The remaining boilers are to change to biomass or heat pumps. While this, on the one hand, increases the RE share beyond 30%, it also increases both electricity demand and biomass consumption.

3.2.3. Orkney's Future

All the suggested transition steps, together, result in an RE share of 38% (cf., before 18%) for the PES of Orkney next to a 33% reduction in CO_2 emission, while the other key parameters can be found in Section 4. Figure 2 shows all input and output specifications of the reference and transition scenario for Orkney. This illustrates that one of the focus areas in the transition, namely fossil fuel consumption, is changing the most. Instead of using these, electricity replaces some of the corresponding demands, while biomass supplies others.



(**a**)

(**b**)

Figure 2. Sankey diagrams of energy flows in GWh for Orkney for 2014 (**a**) and 2030 (**b**) [32].

To address the remaining fossil fuels in transport, a replacement with electro- or biofuels could be considered, similar to Samsø, with either local biogas production or additional hydrogen. However, if electricity-based fuels are considered, the amount of excess electricity can be taken into account, which still makes up a large share. Alternatively, additional RE capacity might be required to allow these further electrification measures.

As further illustrated in Figure 2, the industrial demands have not been addressed with these improvements of heating and transport sector. Due to insufficient data and the unusually complex conditions in the industrial sector, an optimization of it requires an in-depth study. Another recommendation is therefore the investigation of this sector, besides the transport sector, which still relies largely on fossil fuels. The second Sankey diagram in Figure 2 presents Orkney in the second RE integration phase, after which further balancing and interconnections are needed to approach the next phase towards the 100% RE target.

3.3. Madeira, Portugal

Madeira lies isolated both from the lands and from the electricity grids of Europe and Africa. In comparison to Samsø and Orkney, it therefore presents the only true island system, supplying itself almost independently and even incinerating its produced waste to the best extent possible. Further differentiating it from most other European areas, Madeira has the typical characteristics of a southern climate, with high solar radiation and cooling demands rather than a heating demand. For the reference model, 2014 is selected to represent a normal weather year, especially in regards to precipitation and the impact on hydropower.

3.3.1. Madeira Today

With a population of around 250,000, Madeira represents the largest population and island of the three. However, the production of RE and some of the energy demands are not necessarily as big as to be expected in comparison to Samsø and Orkney. The demands are, to a large extent, covered by fossil fuels, but also a variety of RE [64–66].

Thermal power plants are still used for grid stabilization, run mostly on fuel oil or gas, and produce most of the electricity needed on Madeira [65]. Hydropower plants form the second largest production group with dammed and river hydro plants with small reservoirs suitable for hourly flexibility [65]. The wind farms have a total capacity similar to the reference models of Samsø and Orkney, but a much larger PV capacity relating to the comparably higher potential. This, however, is limited due to difficulties with the grid frequency. Finally, the annual waste of more than 100,000 t produces electricity through incineration [66].

Next to the RE for electricity production, solar radiation is further used for heat production. Other heating fuels are electricity, biomass, gas, and a minor share of oils—50% of the oil is otherwise needed in the transport sector [67]. In total, the reference model shows that 11% of the PES is based on RE, including waste incineration. The electricity production, however, is made up by 29% RE, despite limits in the RE exploitation.

3.3.2. Transition of Madeira

Without an interconnection, Madeira is the only SMILE island with an autonomous electricity grid. Therefore, the dependency on fuel imports and need for better utilization of local resources are even greater than for most other islands. With a current RE share of 11% and CO_2 emissions of 895 kt, Madeira presents a contrast to the other islands with a much lower CO_2 per capita, but a similar transition process towards 100% RE system is required nonetheless.

The Madeira reference energy system has 115 MW RE capacity, which is far from sufficient for the comparably large electricity demands, resulting in major fossil power production. However, there are limits to an RE expansion due to grid and stabilization issues. The transition of Madeira towards higher RE shares therefore looks a bit different from Samsø and Orkney, with the RE introduction phase reached and large steps required to reach the second phase.

The existing circumstances are considered in the definition of the SMILE demonstration projects for Madeira, as well as the further transition steps. SMILE addresses the existing PV installations and the sensitive grid with BESS for both residential and commercial buildings, as well as the optimization of the transport sector through touristic and private EVs. This is tested in a comparable small scale considering the size of the island, but is further explored as can be projected by 2030. The overall target on Madeira lies in the optimization of local resources and the reduction of fossil fuels in the power production and transport sector through smart grid solutions [18]. For this, power plant stabilization is reduced and the new SMILE technologies added to the EnergyPLAN model.

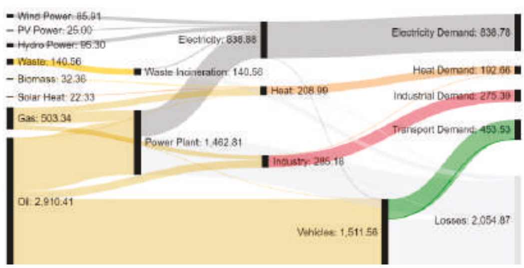
Next in line in the transition is the incorporation of the plans for additional PV, hydro, and wind capacity [68]. Thereafter, the transport sector is addressed closer: After the introduction of EV for commercial, touristic, and private purposes, with the addition of smart chargers, a further exploration is expected. Similar to Orkney, an exponential increase of EV by the year 2030 is modeled with the inclusion of a V2G option, reducing the production at the power plant by enabling EVs to be used as temporary electrical storages. The same approach as on Orkney is assumed and modeled [48].

Eventually, also the heating sector must be addressed to reach higher RE shares. A first logical step is the replacement of oil and natural gas for heating with heat pumps. In the same step, more solar thermal is explored, while reducing the electricity requirement to hours with insufficient solar resources.

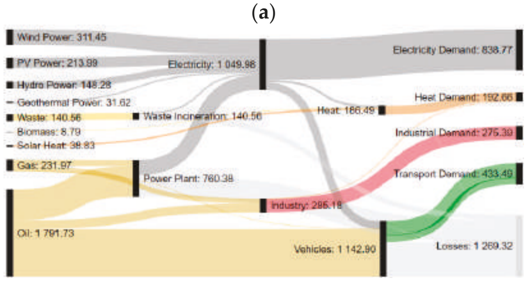
3.3.3. Madeira's Future

The result of the additional capacities, as well as of the other assumed improvements by 2030, is an RE share of the PES of 31%, while the share for the electricity demand is at 71%. Additional RE capacity would increase both even further, but would at the same time result in critical excess electricity production, so the benefits would be limited. Therefore, a more balanced approach towards the 100% RE share is required in the longer term, especially for an autonomous energy system like Madeira.

Figure 3 shows the resulting energy flows of the reference and transition scenario, while the detailed data are found in Section 4. The major change that can be noted is the reduction in fossil fuels, mainly oil from 2014 to 2030. Instead, electricity is produced more from RE, but further optimization should be found for the remaining oil and gas consumption. Generally, the transition could be more successful with the RE integration on all levels and in combination with balancing and storing technologies.



(**a**)



(**b**)

Figure 3. Sankey diagrams of energy flows in GWh for Madeira for 2014 (**a**) and 2030 (**b**) [32].

As it could be tested for Samsø and expanded on Orkney, hydrogen production through electrolyzer could become relevant for the replacement of fossil fuels in the transport sector. Alternatively, biogas production could be pursued. For the second technology, the local biomass potential—both dry and wet—should be evaluated before it can be included in the model.

The final point of discussion relates to the heating sector transition, since—also here—changes are required for the overall development of the Madeira energy system towards 100% RE. The uncertain heating demands currently covered by electricity can provide relevant information for possible improvements. If inefficient boilers and heaters are used, a replacement with efficient heat pumps or even the establishment of district heating could improve the energy system. Besides the uncertainties in the heating sector, the cooling supply could be evaluated and improved. With the possibility of district cooling, the service sector of Madeira could achieve benefits through more suitable supply technologies, ultimately benefitting large-scale RE integration.

4. Overview and Discussion

This section presents an overview of the different scenarios and resulting island energy systems' characteristics after implementation of various smart grid and balancing technologies in the transition towards 100% RE. It shows the short-term changes with their potentials and challenges on three cases and suggests options for other islands. Even though the three islands are of different sizes and populations, some similarities in regard to their energy systems can be identified. By presenting the different RE capacities and their impacts, possible gaps or potentials in the plans and models of other islands can be found and help shape the future creation of sustainable island energy systems.

The energy demands are presented by sectors with the reference and short-term scenarios in Table 3. Here, the main changes are due to more electricity being used in the heating or the transport sector, while the total demands generally stay the same.

Table 3. Comparison of energy demands.

Annual Data	Samsø		Orkney		Madeira	
	2015	2030	2014	2030	2014	2030
Electricity Demand (GWh)	25.5	41.8	154.7	195.0	838.8	1042.7
Heat Demand (excl. electric) (GWh)	46.3	21.3	69.4	38.7	192.7	76.0
Transport Demand (GWh)	30.0	28.9	103.9	99.7	453.5	433.8
Industry Demand (GWh)	0.4	0.4	189.4	189.4	275.4	275.4

The different approaches for the islands in regard of added RE capacity and resulting RE production are shown in Table 4. Despite the plans of decommissioning the power plants on Madeira, as well as reducing the dependence on the power plant on Orkney, the energy system analyses show some still required power production from these.

Table 4. Comparison of electricity production.

Annual Data	Samsø		Orkney		Madeira	
	2015	2030	2014	2030	2014	2030
Wind power capacity (MW)	34.4	34.4	48.3	52.8	45.1	133.1
PV capacity (MW)	1.3	11.5	1.2	11.5	19.1	121.7
Tidal and wave capacity (MW)	-	-	-	19.0	-	-
Geothermal capacity (MW)	-	-	-	-	-	30.0
Hydro power capacity (MW)	-	-	-	-	50.7	111.6
Waste incineration (GWh)	-	-	-	-	32.9	32.9
Transmission capacity (MW)	40	40	40	40	-	-
Power plant power supply (GWh)	-	-	41.9	16.0	599.7	311.8

Since the fossil fuel reduction was paid special attention to in order to increase the RE share in the energy systems, they are included in Table 5. It shows that the fossil fuel consumption on Samsø is reduced by 68% between 2015 and 2030 with the presented scenarios. Similarly, on Orkney, this number is reduced by 34% and on Madeira by 40%.

Table 5. Comparison of fuel consumption.

Annual Data	Samsø		Orkney		Madeira	
	2015	**2030**	**2014**	**2030**	**2014**	**2030**
Biomass consumption (GWh)	52.2	74.2	2.0	69.1	172.9	149.4
Oil consumption (GWh)	89.0	36.0	598.8	425.6	2910.4	1791.7
Gas consumption (GWh)	23.4	0.4	94.5	35.5	503.3	232.0
Coal consumption (GWh)	-	-	21.1	12.6	-	-
Total fossil fuels (GWh)	112.4	36.4	714.4	473.7	3413.8	2023.7
Total consumption (GWh)	164.6	110.6	716.4	542.8	3586.7	2173.1

In Table 6, the comparison of the RE share generally shows great improvements, with increases of 20% points and more. However, for Orkney and Madeira, it is still a long way to the large-scale and 100% RE share targeted, despite the ambitious scenarios to improve the energy systems presented in this report. This can partly be explained by the more balanced approached taken in the scenario creation, rather than a simple increase in RE capacities. The latter would increase the RE share, but also the export and potential curtailment/critical excess production. Instead, more moderate capacity additions are introduced, together with balancing options, such as smart charging and storage options, presenting one approach for the smooth transition to 100% RE.

Table 6. Comparison of energy system indicators.

Annual Data	Samsø		Orkney		Madeira	
	2015	**2030**	**2014**	**2030**	**2014**	**2030**
RE share of PES	60%	85%	18%	38%	11%	31%
RE share of electricity demand	94%	96%	66%	85%	29%	71%
Imported electricity (GWh)	1.5	1.8	10.8	3.8	0.0	0.0
Exported/Excess electricity (GWh)	87.5	93.4	48.9	46.0	0.0	0.2
CO_2 emissions on island (kt)	28.5	9.7	186.0	124.9	894.5	541.1
CO_2 emissions per capita (t)	7.7	2.6	8.5	5.7	3.5	2.2
Total socio-economic costs (M€)	16.5	15.6	57.7	59.6	315.7	337.2

Further indicators included in Table 6 are electricity import and export/excess production to show the share of local energy consumption and self-sufficiency. Samsø's share of RE electricity is close to 100% and, despite the suggested RE capacity increase, the share of the local electricity that is exported is reduced, as more can be used on Samsø now. The same applies to Orkney, which furthermore reduces the import share from 7 to 2% of the electricity demand. Finally, with different framework conditions on Madeira without import/export option, it is possible to keep the critical excess production at 0.02%. This shows the strength of including the full energy system in the transition, instead of focusing on the electricity sector only. While RE capacity could be further increased, improving the RE share in the electricity sector, it would lead to increased excess production, if not integrating the energy sectors. A step-by-step transition approach is therefore proven and recommended, despite being more complex and requiring a more integrated energy system.

Similarly, the CO_2 emissions are reduced with the increase of RE and decrease of fossil fuel combustion. On Samsø, the reduction is 66%, 33% on Orkney, and 40% on Madeira. The final CO_2 emissions are equal to annually 2.6, 5.7, and 2.2 t per capita for Samsø, Orkney, and Madeira, respectively. The high amount for Orkney might relate to the big industrial sector and limited biomass potential.

Finally, the last row of Table 6 shows the tendencies for annual total socio-economic system costs with current data on technologies, fuels, operation, and CO_2 costs. For each of the islands, the annual costs are similar or even decreased in the short term—compared to the references—by −5, +3, and +7%. Considering the large investments in new technologies and infrastructure, these values are acceptable and come with possible long-term benefits. While fuel and CO_2 costs drastically decrease, the annual investments increase by 34, 61, and 120%, respectively, showing how the money is being spent on local infrastructure instead of imported goods now.

The three islands are all presenting cases of reduced or stabilized electricity import and export, with strongly improved CO_2 values at acceptable socio-economic costs, in the transition to 100% RE systems. Taking into consideration the different phases of the transition, as well as the sensitive and specific circumstances for each island, an increase in RE share can be achieved.

5. Conclusions

Investigating the transition towards 100% RE supply for islands, this paper presents transition scenarios for Samsø, Orkney, and Madeira with their potentials and challenges. Built upon reference energy systems of 2014/2015, scenarios are created incorporating smart grid demonstration projects, as well as further possibilities in the energy system, to present energy system scenarios of 2030. Local conditions influence the possibilities, as do local plans and strategies. These are incorporated into suggested steps for a transition to higher RE shares as a three-phase approach, of which Samsø is the farthest ahead, while Orkney and Madeira are in the second phase from low towards high RE share. The resulting short-term scenarios of 2030 generally show that local conditions and opportunities vary, which leads to the conclusion that every transition, island, and energy system is unique and must be evaluated separately, while some similarities exist.

This article presents Samsø's energy system moving from the reference system, with already large-scale RE integration, towards a system with 100%, resulting in the incorporation of technologies focusing at balancing the energy system instead of further increasing RE capacity. As part of this transition, the local abundance of wind energy and biomass, as well as transmission capabilities, influence the technical choices leading to the next phase. While some technologies are specific for Samsø, they can generally be replicated and thereby improve island energy systems in various ways.

Orkney's reference energy system is characterized in the RE introduction phase, hence the increase of this to large-scale RE integration is currently in focus, instead of balancing the energy production and demands. With local limits in their transmission grid, but otherwise good RE conditions, the smart grid solutions and integration technologies are chosen accordingly. As this paper shows, more potential RE capacity would still be required, as well as the further exploration of sector integration, to support fragile energy systems such as this.

Madeira is in the process of introducing more RE to their energy system and aiming at an increase of its share, hence being in the beginning of the RE integration phase. Therefore, Madeira's short-term development focuses on the expansion of various RE capacities, as well as the potentials in the transport and heating sector. Without a transmission line, the autonomous energy island already requires balancing options through sector integration and making use of local hydropower production and storage. The combination with smart grid applications plays another major part in autonomous energy systems, such as Madeira.

This case study demonstrates possible transitions to 100% RE systems, which is taking place all over the world. With new problems coming into view with an increased RE share, new solutions are presented and tested for three islands. With islands being potential representatives of bigger energy systems, the results can be transferred to other systems as well. However, individual variations are also to be expected, as is shown from the demonstration islands in this report depending on their current development phase. While an interconnection can ease the transition, balancing and integrating technologies are even more important, as well as the local conditions. Further smart grid technology employment could support this further. This case study shows a variety of energy systems and solutions and therefore gives examples of the required transition of islands towards 100% RE share. The general tendency points to smart and balanced planning of the next steps to ensure this.

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preparation, H.M.M.; writing—review and editing, H.M.M., P.A.Ø., and S.R.D.; supervision, P.A.Ø. and S.R.D.; project administration and funding acquisition, P.A.Ø.

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Article

Exploring Energy Pathways for the Low-Carbon Transformation in India—A Model-Based Analysis

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Abstract: With an increasing expected energy demand and current dominance of coal electrification, India plays a major role in global carbon policies and the future low-carbon transformation. This paper explores three energy pathways for India until 2050 by applying the linear, cost-minimizing, global energy system model (GENeSYS-MOD). The benchmark scenario "limited emissions only" (LEO) is based on ambitious targets set out by the Paris Agreement. A more conservative "business as usual" (BAU) scenario is sketched out along the lines of the New Policies scenario from the International Energy Agency (IEA). On the more ambitious side, we explore the potential implications of supplying the Indian economy entirely with renewable energies with the "100% renewable energy sources" (100% RES) scenario. Overall, our results suggest that a transformation process towards a low-carbon energy system in the power, heat, and transportation sectors until 2050 is technically feasible. Solar power is likely to establish itself as the key energy source by 2050 in all scenarios, given the model's underlying emission limits and technical parameters. The paper concludes with an analysis of potential social, economic and political barriers to be overcome for the needed Indian low-carbon transformation.

Keywords: energy system modeling; decarbonization; global energy system model (GENeSYS-MOD); renewables; India; energy transformation; energy transition; sector coupling

1. Introduction

India is one of the crucial actors when international climate mitigation goals are to be met. Today, the country already contributes almost 18% to the world's population and is set to account for around one-quarter of the projected rise in global energy demand by 2040 [1].

In 2015, India emitted 1869 Mt CO_2 in total, of which 51% came from power and heat generation. At present, the Central Electricity Authority of India (CEA) projects total estimated CO_2 emissions of 983 million tons for the year 2021–2022 and 1165 million tons in 2026–2027 [2]. The main driver of this absolute increase is expected growth of total energy demand. The projected peak demand is 235 GW, with an overall energy requirement of 1611 TWh at the end of the year 2022 [2]. Energy consumption is expected to rise further by 32% from 2022 to 2027 [2].

India submitted its Intended Nationally Determined Contribution (INDC) on 1 October 2015. On the national level for India, it implies three key goals to achieve this agreement:

(i) to reduce the emissions per gross domestic product (GDP) output by 33% to 35% by 2030 from 2005 levels;

(ii) to increase the cumulative electric power installed capacity from non-fossil fuel-based energy resources up to 40% by 2030;
(iii) to create an additional carbon sink of 2.5–3 billion tons of CO_2 equivalent through additional forest and tree cover by 2030 [3].

The Draft National Electricity Plan by the CEA [2] includes the INDCs, targeting a path of electricity generation and reduction of greenhouse gas (GHG) emissions in line with the Paris pledges.

By contributing to global climate efforts, India pursues international but also domestic objectives. The adverse consequences of climate change have a significant impact on the Indian population and economy, as weather extremes influence the important agriculture sector and the security of food supply [4]. Furthermore, the rise of the world temperature affects India through climate migration, water scarcity, and famine. In addition, the energy sector is an important element of India's future development strategy, seeking to reduce poverty, reduce local pollutants, and assure access to electricity for all [5]. Along with the aim to achieve the sustainable development goals (SDG), especially SDG7 "Ensure access to affordable, reliable, sustainable and modern energy for all" and SDG13 "Take urgent action to combat climate change and its impacts" established by the United Nations (UN), India seeks to make its energy system sustainable, and thereby enhance the population's living conditions.

According to the 2015 Paris climate agreement, India will revise and resubmit its INDCs by 2020. In this context, the potential contributions of sustainable energy supply have received particular interest, e.g., the future of coal as the baseload power, the potential role of natural gas as a "transformation fuel", and the potential of renewable energy to contribute to sustainable energy development. Given the global acceleration of renewable deployment, in particular solar energy, the INDCs currently developed for 2020 may be more ambitions than those back in 2015, and perhaps not even more expensive.

In addition to meeting targeted climate goals, India may benefit from a fast energy transition from both a sustainable energy and a geopolitical perspective, due to its current dependency on fossil fuels and energy imports [6].

There is a broad and growing literature base on the perspectives of the Indian energy system, to which our paper seeks to contribute. Bhushan [7,8] laid out the principle challenges to governance of energy resources for India that are still valid today, e.g., the energy–poverty challenge, central and regional coordination, the role of coal, nuclear, and renewables, and the insertion of India into global resource markets and innovation systems. Bhushan [8] stressed that India is expected to fulfill its INDC targets for 2030 easily and the focus now lies on the long-term planning. Identifying challenges, such as the need for improvements in the transmission infrastructure and facilitating access to low cost finance, is important for successful development. Currently, there is a market shift towards renewable energy sources (RES) through decreasing prices for renewable power generation, including a rapid innovation in technology [9,10].

The role of coal, and the competition with other fuels for financial resources and policy considerations, is also addressed by the Boston Consulting Group (BCG) [11] and Tripathi et al. [12].

The Indian energy sector has also been subject to model-based analysis in the context of recent policy and technology developments. In the context of the global sustainability initiative launched by Sachs [13] and Transport Scenarios by Dhar et al. [14], both studies identify possible challenges and opportunities of a low-carbon transformation of the energy and economic systems.

Löffler et al. [15] developed a cost-minimal path for the global energy system up to 2050, including India as part of ten global regions. The paper focuses on the interdependencies between traditionally segregated sectors, including electricity, transportation, and heating. Due to the scale of the referenced model, detail within the model node India is lost, which this paper will address.

A comparably different model-based approach is chosen by the Integrated Research and Action for Development (IRADe) [16]. The IRADe's low-carbon sustainable development (LCSD) model is a dynamic, multi-sectoral and intertemporal linear programming activity analysis model based on an input–output framework. In addition to scenarios which target the compliance with CO_2 budgets of

155 Gt (LC1 scenario) and 133 Gt (LC2 scenario) for India by 2050 and a baseline scenario "dynamics as usual (DAU)", the IRADe also includes human development thresholds and well-being indicators within the "visionary development (VD)". The results of the LC1 and LC2 scenarios conclude that the CO_2 budgets can be met by 2050, but cause a decrease in the overall GDP growth throughout the years.

The Massachusetts Institute of Technology (MIT) has developed a multi-sector applied general equilibrium model of the Indian economy that uses CO_2 emissions from burning fossil fuels to generate a 2030 reference case [17]. Sectoral imports and exports capture transactions with the rest of the world. The MIT developed various scenarios, such as the "emission intensity" scenario, which imposes India's NDCs, and the "non-fossil scenario", corresponding to India's non-fossil electricity capacity target of 40% installed non-fossil electricity capacity by 2030. The "combined" scenario simulates the jointly pursued targets of both "emission intensity" and non-fossil electricity. While both "emission intensity" and "combined scenario" lead to the same emission intensity in 2030, the combined scenario includes the additional constraints of non-fossil electricity targets.

Shukla et al. propose an integrated modeling framework [18,19] for analyzing alternative development pathways with equal cumulative CO_2 emissions within the first half of the 21st century. They provide a comparison of alternative development strategies on multiple indicators, including energy security, air quality, and technology stocks. Short and long-term drivers of decarbonization pathways for several regions, including Europe, the United States, China, and India are explored in a multi-model decomposition analysis by Marcucci and Fragkos [20]. Their research finds that in the short term, energy efficiency improvements are the key strategy to achieving current climate targets. In a joint project between the Indian planning office National Institution for Transforming India (NITI Aayog) and MIT, Singh et al. [17] employed a numerical economy-wide model of India with energy sector detail to simulate the impact of India's commitments to the Paris Climate Agreement.

Focusing on India's important renewable potentials, Gulagi et al. [21] explored the conditions under which India could be supplied by 100% RES by 2050. Similar exercises, with a lower level of detail, for a 100% renewables-based energy supply for India were prepared by Teske et al. [22], Jacobsen et al. [23] and Löffler et al. [24]. International organizations, too, have put a focus on India and its energy challenges, such as the International Energy Agency (IEA) [25] World Energy Outlook ("India Focus"). Shortcomings of the above-mentioned research, however, include a limited focus on electric power (no sector coupling), which will be addressed in this paper.

This paper adds to the existing literature by exploring alternative pathways to sustainable energy system development in India that respect both the specifics of the current energy system, but also stringent climate targets and global technological trends favoring non-fossil, low-cost solutions. We deploy an open-source linear cost-optimizing global energy system model (GENeSYS-MOD) to analyze different scenarios to meet increasing demand in India until 2050. A particular feature of the model is the regionalization of India into 10 regions. Thus, the model is able to illustrate regional idiosyncrasies, as well as potential imbalances, in the future energy system. The model not only focusses on the electricity sector, but also provides an in-depth analysis of the heat and transportation sectors. The implementation of different scenarios enables a qualitative comparison of the total cost for the specific optimized energy pathways until 2050. Thus, the results provide a comparability of the total cost of the different scenarios.

Projecting future energy scenarios for India also needs to account for other aspects besides the technical potential of renewables. An assessment of present literature and expert interviews is therefore used to set the modeled low-carbon energy transformation in context with the social, political and economic environment. The low-carbon transformation of the energy sector is not solely driven by climate consideration, but is inserted into a complex process of sustainable development that includes (amongst others) reducing health risk, affordable energy and a circular economy. In order to make an evaluation about whether the country is truly able to become mostly RES based in 2050, further implications on India's energy transformation have to be considered. The main sources for the literature review regarding the contextualization of the model results were, in particular "The Political Economy of Clean Energy Transitions" by Arent et al. [26], which is a distilled compendium of cross-cutting academic projects on clean energy transitions, "India's low carbon transition" by Pandey [27], "India: Meeting Energy Needs for Development While Addressing Climate Change" by Joshi et al. [28], and "Coal Transition in India-Assessing India´s energy transition options" by Vishwanathan et al. [29].

After this introduction, Section 2 sketches out the status quo of the energy system in India with respect to existing technologies and recent trends on policies and technological developments. Section 3 provides a non-technical description of the model, and develops the three scenarios, the results of which are reported and discussed in Section 4. Section 5 identifies potential barriers to a low carbon transition and is followed by the concluding Section 6.

2. Status Quo of the Indian Energy Sector

2.1. Energy Mix

The current energy mix of India is dominated by coal, with a share of 58% of electricity generation in 2017, and 193 GW installed capacity. India is the third largest producer of coal and still holds the fifth biggest reserves [30]. Most of India's coal resources can be found in the eastern regions of Jharkand, Chhattisgarh, and Odisha [31]; they are also the basis for the heavy industry, like steel and metallurgy, benefitting from close-by coking coal and convenient supply chains. The coal sector is currently one of the strongest lobbying groups in Indian energy politics. The public mining company Coal India Limited (CIL) alone employs over 310,000 people [32]. Power production relies mostly on coal and the biggest share of installed coal capacities has been added in the last 15 years [31]. Around 45% of all Indian thermal power plant capacities are coal based and younger than 10 years. This implies that the remaining power plants will potentially not be in line with medium and long-term climate targets.

Natural gas contributes about 7.2% to electric power generation [33]. A large share of the natural gas has to be imported and—given the relatively high cost—natural gas has not yet obtained a significant share of the electricity mix. Nuclear energy plays an important political role, in particular in regional and international conflicts (e.g., with Pakistan), but its contribution to electricity generation is small (2.7% of generation and capacity) [34].

Small-scale and large-scale hydropower have a share of 20% and 16% in installed capacity and electricity generation, respectively. There is a controversial discussion about the future development potential of hydropower, which has a high theoretical potential, but significant practical and political challenges to its realization [8].

Renewable energy in India has several applications, the most important being biomass fuels for cooking and heating. Non-commercial energies, mainly biofuels and waste, made up about 23.1% of India's primary energy supply in 2015 [1]. With respect to electricity, the installation of grid-connected renewable generation capacities (excluding large-scale hydropower) is small, but rapidly rising at a rate of 20–25% annually over the last 15 years [7,8]. Wind energy dominates this trend, accounting for 32.8 GW of installed capacity, followed by solar photovoltaics (PV) (17.1 GW), and small hydropower (4.4 GW) as of January 2018 [35]. India's renewable energy sector has already reached a size of economic relevance for the whole country. India has a total renewable capacity share, including large hydro power, of around 32% of its installed capacity as of January 2018 [36]. In 2016, it directly and indirectly employed around 385,000 people (large hydropower plants add additional 200,000 jobs) in the renewable energy sector [37]. From April 2014 to December 2016, the equity flow into India from foreign investors surpassed US$ 2 billion [38], which was established under the Paris Agreement and is to be fully implemented in the next couple of years. As these types of investments will continue to grow [39], specific plans for an expansion of investments into renewables in developing countries have been designed. India's Prime Minister Modi, along with former French President Hollande, initialized the International Solar Alliance to mobilize US$ 1 trillion of investment worldwide into solar energy programs [40]. In addition to fiscal incentives such as accelerated depreciation, India's government has also eased the path for renewable projects [38]. Some examples are the setup of big solar parks with over 500 MW over the coming years, and mandatory ratios for rooftop solar to involve cities in renewable investments.

Just like coal, the installed capacities for renewables vary significantly between different states and regions [26]. The western regions have invested much more into renewables compared to the rest of the country. These states are almost all governed by the Bharatiya Janata Party (BJP), the national ruling party. Furthermore, these states are also the ones with very little coal and steel industry.

2.2. Government Plans

2.2.1. Official Plans by the Indian Government

The CEA government regularly establishes longer-term development plans, the most recent one ranging from 2017 to 2022 [2]. This plan includes a capacity increase of about 50 GW of coal-based power projects currently under way, as well as an increase in RES share (Table 1). However, the plan also states that no additional coal power plants are required after 2022. The CEA also predicts additions of 4.3 GW of natural gas, and 2.8 GW of nuclear power until 2022.

Table 1. India's renewable energy sources (RES) addition in GW predicted by the Central Electricity Authority of India (CEA) based on GOI—Ministry of Power [2].

RES Category	Installed Capacity as on 31 March 2016	Expected Capacity Addition from 2017 to 2022	Target RES Installed Capacity as on 31 March 2022	Expected Capacity Addition from 2022 to 2027
Solar	18.7	81.3	100	50
Wind	31	29	60	40
Biomass	5.4	4.6	10	7
Small Hydro	4.5	0.5	5	3
Total	59.7	115.3	175	100

Simultaneously, the CEA has set ambitious plans to expand renewable capacities by 2022 (Table 2). Thereby, the summarized total capacity addition until 2022 is targeted at 137.8 GW [2]. Consequently, the expected share of "non-fossil" based installed capacity, which is defined as nuclear power, hydropower, and RES by the CEA, is likely to increase to 46.8% by the year 2022 and will further increase up to 56.5% by the year 2027. Total renewable energy generation of about 20.3% will contribute to the total energy generation requirement in 2022 [2].

Table 2. India's RES addition predicted by the CEA based on GOI—Ministry of Power [2].

Year	Energy Requirement (TWh) [1]	Peak Demand (GW) [2]
2015	1114	153.4
2022	1611	235.3
2027	2132	317.7

[1] After considering reduction in demand due to demand side management (DSM). [2] After reducing solar and wind generation (i.e., variable renewable energy (VRE) generation).

3. Model and Scenarios

3.1. Global Energy System Model: A Linear Energy System Model

This paper uses a modified version of the GENeSYS-MOD, an open source tool for the linear optimization of energy systems. It is based on the open-source energy modeling system (OSeMOSYS) by Howells et al. [41] and minimizes a cost function to find the lowest discounted cost solution for an energy system to meet a given energy demand. It also allows for temporal and regional disaggregation and is thereby able to model pathways of development of diverse energy systems. In particular, our implementation is based on the version of GENeSYS-MOD by Löffler et al. [15], whereby calculations were done using their general algebraic modeling system (GAMS) code adaption based on the initial OSeMOSYS GAMS translation by Noble [42]. GENeSYS-MOD is a powerful tool to help to identify the lowest-cost solutions and pathways for the energy transformation necessary to keep global warming below 2 °C.

One of the strengths of GENeSYS-MOD is its adaptable and flexible structure. As shown in Figure 1, it is organized into multiple blocks. The basic OSeMOSYS implementation contains seven blocks, including the *objective function*, *costs*, *storage*, *capacity adequacy*, *energy balance, constraints*, and *emissions*. GENeSYS-MOD includes three additional blocks *renewable target*, *trade*, and *transportation*, as well as a reworked implementation of the *storage* block. All these blocks serve different functionalities within the energy system model, as all costs, energy production, consumption values, and constraints, such as on investments or capacity additions, need to be accounted for. The block *capacity adequacy* ensures that necessary capacities are met at all times, while the *energy balance* levels energy use and production, taking into account efficiencies of technologies. A more detailed discussion of the blocks composing the model can be found in Löffler et al. [15] and Howells et al. [41]. This research paper includes an endogenous transmission network upgrade as part of the *trade* block, which allows the model to extend existing transmission capacities, focusing on the trade of electricity. For this extent, capacities of grid infrastructure, as well as capacity expansion costs based on line length, have been added to the model equations.

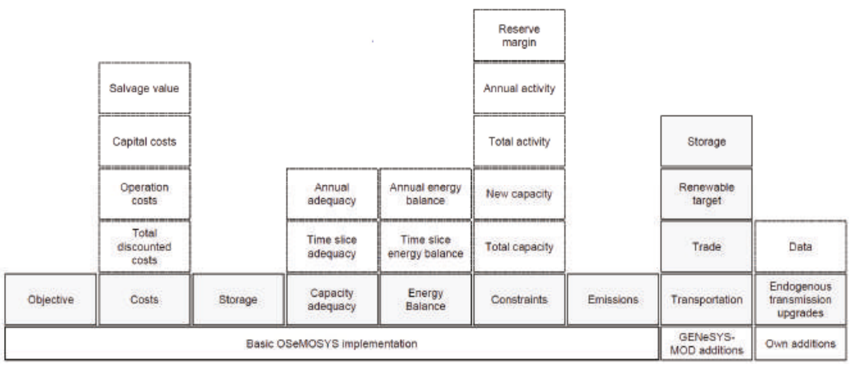

Figure 1. Layout of the Global Energy System Model (GENeSYS-MOD) with new additions based on Löffler et al. [15]. OSeMOSYS: open-source energy modeling system.

The original, global model application was adjusted for the analysis of India's energy system on a detailed level. Amongst other things, we have introduced a constraint on renewable capacity extensions (50% on previous figure every five years), which reflects institutional and political constraints of expanding renewables. Also, grid connections between the ten regions can now be calculated endogenously, improving the interpretation of the spatial aspects of energy system development.

3.2. Data and Limits of Our Model

Our model requires strong assumptions for input; hence, reliable data on, i.e., demand or RES potentials is essential (see Appendix A for key representative data). The power, heat (Table A1), and transport (Table A2) demand in our model is significantly determined by projected population growth and to a smaller extent due to a rise in urbanization [43]. Due to the integrated modeling approach for the entire modeling period from 2015 until 2050, only a limited number of time slices per year can be included (six time slices, including three distinct seasons, winter, summer and intermediate (autumn, spring), each consisting of day and night to model seasonal fluctuations, respectively, see Table A3). Furthermore, cost developments of implemented technologies are given exogenously.

The results allow for a both qualitative and quantitative assessment for: (1) whether India can achieve an energy system consisting of 100% RES; (2) where the current trend is going; and (3) where we see further steps are necessary.

3.3. Regional Disaggregation of the Indian Energy System

India has an enormous potential for renewable energies. Due to geographical circumstances, regional disparities in potentials for renewable energy technologies occur and are considered within the model according to Table 3. In total, India has a total solar power potential of 11,195 GW as of 2015 [44]. Estimates of India's wind power potential vary greatly, depending on assumptions on efficiency, hub heights, turbine-size and land-use considerations. The model is based on data which is retrieved from a report of India's wind power potential by Hosain et al. [34]. The total onshore wind power potential for India is estimated to range between 2733 GW and 6439 GW. The highest potentials are observed in the western and southern regions, where most of the installed onshore wind capacities already exist. Data regarding India's offshore wind energy potentials are retrieved from Löffler et al. [15] and are proportionally assigned to the coastal regions (see Section 3.1) according to the coastal kilometers of the relevant regions.

Table 3. RES potentials in GW based on GOI – Ministry of Power [45] and Hosain et al. [44]. N = north. NW = north-west. W = west. CW = central-west. CS = central-south. S = south. E = east. CE = central-east. NE = north-east. UP = Uttar Pradesh. PV: photovoltaics.

RES Technology	N	NW	W	CW	CS	S	E	CE	NE	UP
Solar PV	724	3096	1705	2069	1135	391	276	500	1000	300
Onshore wind	0	394	359	555	955	309	154	0	5	2
Offshore wind	0	0	61	41	14	74	0	0	0	0
Hydro	51	4	3	7	11	5	10	1	59	1

Hydro energy can be divided into large and small hydropower. In India, large hydropower is defined to have a capacity of more than 25 MW, whereas small hydropower has a capacity of less than 25 MW [45]. According to this definition, the country has a total installed capacity of more than 35 GW in large and small hydropower cumulated in 2015 [46]. These capacities are mostly located in the northern regions, as well as in the central–south areas. India has a potential of more than 151 GW of large hydropower, especially in the northern region, due to the Himalaya Mountains and other important river systems such as the Indus. The north, north-west (NW), and north-east (NE) account for more than 75% of the total large hydropower potential in India. In addition, small hydropower has a potential of 19.7 GW.

In order to represent its geographical, industrial, and political diversity, India is split into different zones. We follow the approach by Gulagi et al. [47] and split India into ten zones, along respective federal state borders (Figure 2). Thus, the following regions are obtained:

- the north (N) consists of Jammu and Kashmir, Himachal Pradesh, and Uttarakhand, and Is characterized by a decent potential of solar power and very large hydropower potential (51 GW);
- the NW consists of Punjab and Rajasthan, quite rural regions with a significant potential of solar power;
- Gujarat and Madhya Pradesh form the west (W) region, with a broad portfolio of renewables potential (solar, onshore and offshore wind);
- central-west (CW) is comprised of Maharashtra, Goa, and Chhattisgarh, likewise large solar and wind resources, but, particular in Chhattisgarh, a higher level of heavy industrialization and coal;
- India's central-south (CS) is comprised of Karnataka and Andhra Pradesh, with the highest onshore wind potential of the country (955 GW);
- the south (S) comprises Tamil Nadu and Kerala, also featuring solar and wind potential, but very little fossil fuels (except for the liquefied natural gas (LNG) import terminal in Chennai);
- the east (E), consisting mainly of Orissa and West Bengal, appended by Sikkim, has quite heavy industrial roots, and is continuously struggling for electricity supply;

- somewhat similar, the central-east (CE), consisting of Bihar and Jharkhand, has high energy demand, but also a significant potential, in particular of solar energy (1000 GW);
- the NE consists of the somewhat isolated states of Assam Arumachal Pradesh, Nagaland, Manipur, Mizoram, Tripura, and Meghalaya, with some solar and significant potential hydro resources (59 GW);
- Uttar Pradesh (UP), bordering the national capital territory of Delhi, is one of the largest and most heavily industrialized states, with a particular dynamic energy demand.

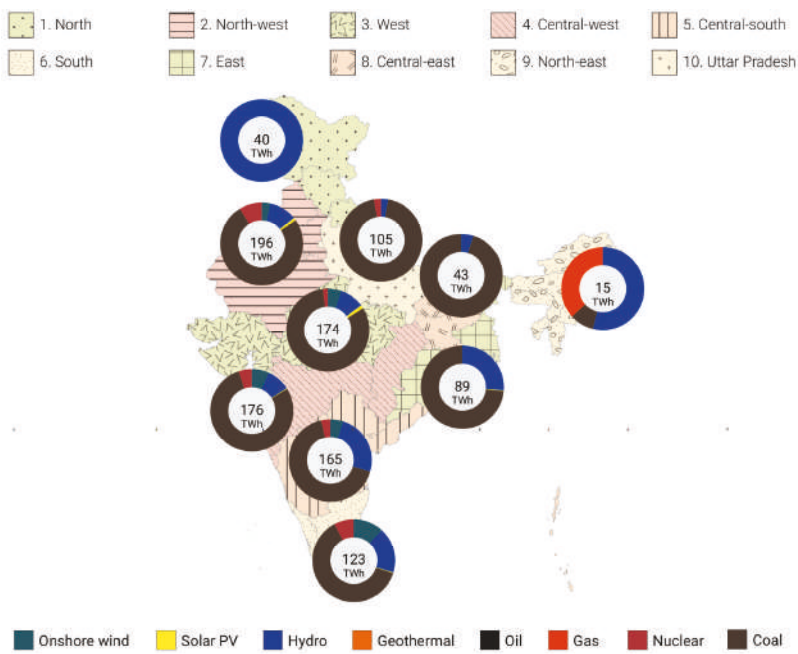

Figure 2. India's regional configuration and electricity production (2015) based on Gulagi et al. [47].

3.4. Scenarios

Current discussions about the future energy direction of the Indian energy sector are quite diverse, varying between the continuations of the traditional coal-based pattern, to the possibility of a 100% supply by renewable energies. In order to cover some of this research gap, while still respecting India's INDC targets, we have developed three distinct scenarios.

3.4.1. Limited Emissions Only Scenario

The limited emissions only (LEO) scenario describes a development where the goal of limiting global warming to 2 °C is respected, and the globally available CO_2 budget is distributed according to current population size. Generally, this corresponds to the 450 ppm scenario of the IEA [48] (now renamed "Sustainable Development Scenario"). The derived emission budget for India is about 118 gigatons from 2015 until 2050 in order to meet the 2 °C target. This budget would be considerably lower if the distribution was based on other characteristics, e.g., GDP or current emissions. The LEO scenario informs decision makers about the potential cost for the Indian economy, especially compared to the rather deviant scenarios and the respective role of fossil fuels and renewables therein.

3.4.2. Business as Usual Scenario

In the business as usual (BAU) scenario, the Indian government (and all other governments) stick to given commitments and signed treaties, but nothing more. In international terms, this corresponds to the new policy scenario (NPS) of the IEA. The BAU scenario uses the projected capacities for renewable energy capacities until 2040 of the new policies scenario by the IEA [31]. These projected capacities are included as upper limits and thus restrict the construction of renewable generation capacities in the model. No specific emission limits for CO_2 or other GHGs are included. The goal of the BAU scenario is to compare the resulting CO_2 emissions with the other two scenarios, where the national CO_2 emissions are fixed by using a national budget. Moreover, the point of interest lies on the pathways after 2040, when the usage of renewable energies is not limited by the projected IEA capacities anymore.

3.4.3. 100% Renewable Energy Sources Scenario

The Indian government has regularly updated its commitment towards using more RES in the future. In contrast to the LEO scenario, the aim of the 100% RES scenario therefore examines if it would be possible to fulfill the total energy demand with 100% renewable energy in 2050. Therefore, the model is restricted such that no non-renewable energies, including nuclear energy, can be used by 2050. The included CO_2 budget of 60 gigatons corresponds with the goal to restrict the amount of global warming to only 1.5 °C.

3.4.4. Further Assumptions

We adopt the assumptions on energy and electricity demand taken from the IEA 2017 World Energy Outlook. A sensitivity analysis is added for all scenarios that reduces demand growth by 50%. This accounts for the uncertainty on increasing energy efficiency, new demand patterns, and a slower adaptation of very energy- and electricity-intensive demand behavior. The assumptions on the cost of conventional and renewable energies (Table 4) are based on a variety of sources. [49–51].

Table 4. Assumptions on the cost of conventional and renewable energies in India based on Schröder et al. [49], Ram et al. [50] and the Energy Technology Reference Indicator (ETRI) [51].

	Technology	2015	2020	2025	2030	2035	2040	2045	2050
Cost in M€/GW	Onshore wind	1280	1152	1050	972	940	900	860	823
	Offshore wind	2560	2304	2100	1944	1880	1800	1720	1664
	Large-scale hydropower	826	826	826	826	826	826	826	826
	Utility-scale solar PV	1000	580	466	390	337	300	270	246
	Biomass	656	656	656	656	656	656	656	656
Cost in M€/PJ	Hard coal	1.06	1.11	1.17	1.23	1.29	1.35	1.42	1.49
	Natural gas	3.30	3.30	3.30	3.30	3.30	3.30	3.30	3.30

4. Results and Interpretation

4.1. Scenario Results and Comparisons

Model results suggest that in all three scenarios, the total energy demand can be met, and that a major change in the fuel mix, away from fossil (mainly coal-based production), to renewables is likely to occur. This change is not only imposed by environmental constraints, but also pushed by the increasing competitiveness of renewables, mainly solar energy.

4.1.1. Limited Emissions Only Scenario Results

In the LEO scenario, the share of fossil fuels is gradually reduced over time, though some fossil capacities are still available in 2050. In the electricity sector, upon which we focus on in this paper, solar takes over a leading role in power generation, resulting in an accumulated share of 69% for all regions in 2050 (Figure 3). Apart from solar, wind and hydropower are the main sources for power generation in 2050 with 17% and 9%, respectively. While wind power is continuously increasing in its capacity after the year 2035, hydropower stays almost constant over all periods. While coal is the main component in the power generation energy mix in 2015 with a share of 82%, it continuously reduced until 2050. A slight increase in coal usage can be observed in 2050. This is due to the huge increase in power generation (induced by sector-coupling effects in the other sectors) between 2045 and 2050, which is compensated for by the already installed coal capacity. Despite the growing energy demand, the power generated by coal is reduced by more than half by the year 2025. In 2050, coal still has a share of about 5% in power generation. Nuclear power is hardly used during the entire period, nor does natural gas play any significant role. Figure 3 illustrates the pathway within the LEO scenario.

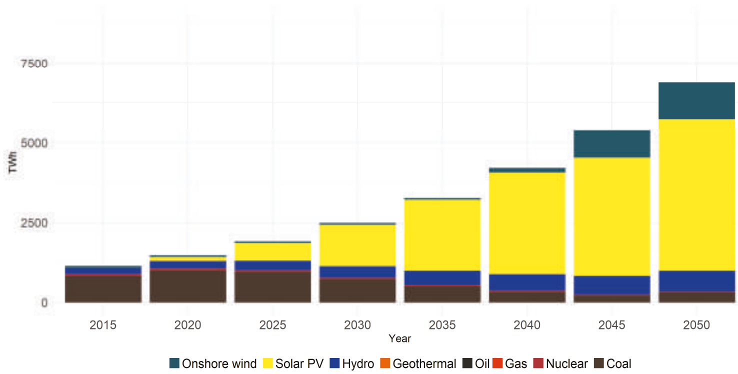

Figure 3. India's power pathway in the limited emissions only (LEO) scenario.

In the rest of the energy system, heat generation is dominated by biomass (60%) and coal-based heating (38%) in 2050. Natural gas, electric heating, and solar heating play only a minor role (Figure 4). The transportation sector has the chance to become emission free by 2050 as well.

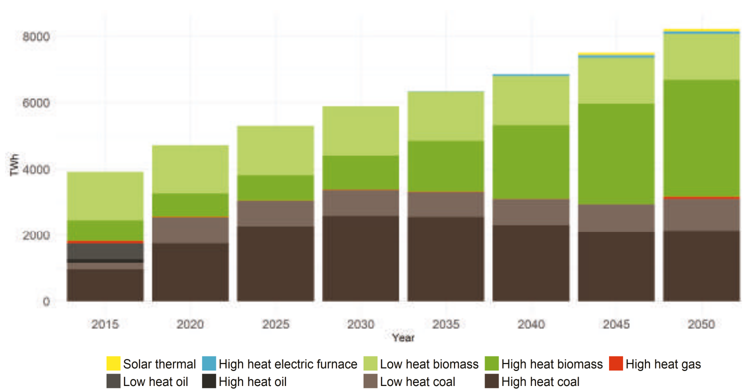

Figure 4. India's heat pathway in the LEO scenario.

Demands for passenger transportation will be fully supplied by electric fueled rail services and battery electric vehicles (BEV) in 2050 (Figure 5). As demand is assumed to increase by up to 3000 million freight km per year in 2050 (+273% compared to 2015), an increase in H_2 powered road trucks and electrical rail traffic can be observed from 2025 on. In addition, the shipping sector will completely become independent of conventional sources (conv.) by using biomass-powered means by 2050. Air traffic is assumed to convert from conventional fuels to hydrogen-based technologies (predicted breakthrough between 2030 and 2035).

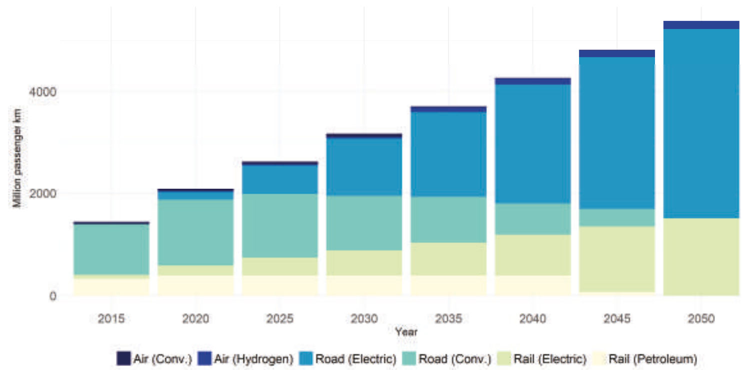

Figure 5. India's freight transportation pathway in the LEO scenario.

In the freight sector, conventional ships in 2015 will shift towards biomass (biom.) powered means. On the road, internal combustion engines will be replaced by hydrogen and biomass run vehicles. For freight transportation by rail, petroleum powered trains will fade out in favor of electric trains by 2050 (Figure 6).

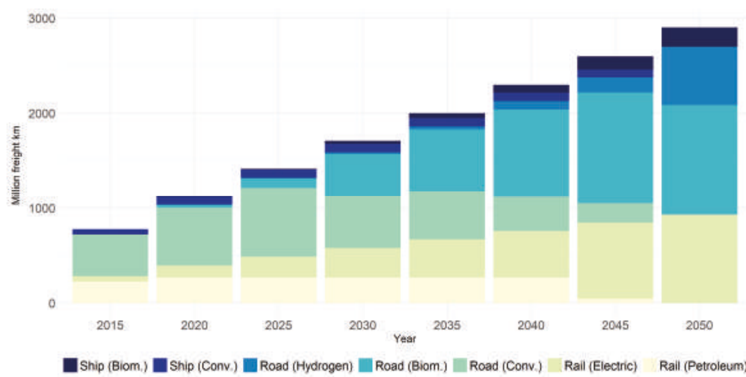

Figure 6. India's passenger transportation pathway in the LEO scenario.

The total emissions within the model amount to 96 gigatons of CO_2 from 2015 until 2050.

4.1.2. Comparison with Other Scenarios

A comparison between the LEO scenario and the BAU scenario confirms that with less stringent climate targets, more fossil energy (mainly coal) is used for electrification. Figure 7 shows the difference between the generation mixes of the LEO scenario, compared with the BAU scenario. In both scenarios, complete decarbonization of the Indian energy system is not accomplished. Differences mainly occur in the more dominant usage of natural gas and coal-based energy throughout the years. Overall, coal as an energy carrier is still declining in the years leading to 2050, having its peak in 2040. Coal still has a share of about 7.4%, whilst natural gas accounts for nearly 1% of the energy production in 2050. Compared to the LEO scenario, solar power (66%) develops on a smaller basis. Wind (17%) and hydro power (9%) remain rather constant over the years. The total emissions are about 9% higher compared to the LEO scenario, but still achieving the 2 °C goal.

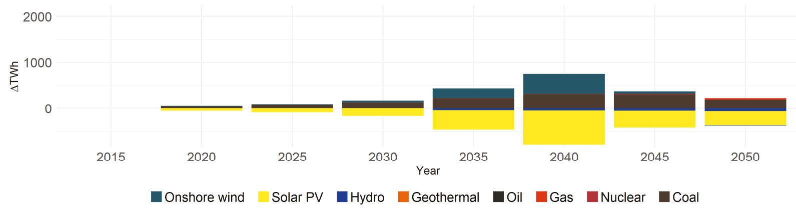

Figure 7. Comparison between the LEO and the business as usual (BAU) scenarios.

Figure 8 shows a similar comparison between the LEO scenario and the 100% RES scenario. The small share of coal (and the marginal share of natural gas) disappears by 2050, and more solar and onshore wind are generated. The contribution of offshore wind is marginal, and hydroelectricity observes a smaller share in the 100% scenario.

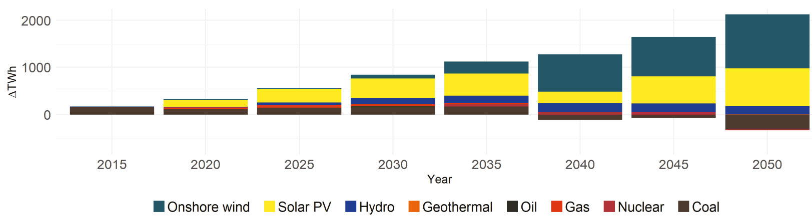

Figure 8. Comparison between the LEO and the 100% RES scenarios.

As stated in the scenario description, the model is forced to only use renewable energies in 2050 in the 100% RES scenario. This leads to a much higher power demand over the years, which is due to the increased usage of power-to-x technologies in the heat and transportation sector. Compared to the other scenarios, power trading between the nodes is even more relevant because of the regional differences in the potentials for renewable energy generation. Natural gas does not play a role in the energy mix within this scenario. Solar and wind power replace the then phased-out coal-based energy, leading to a 15% decrease in CO_2 emissions until 2050. The research shows that with the given potentials, a 100% renewable energy system, meeting the 1.5 °C climate target, would be feasible in the year 2050. Regarding heat and mobility, no significant differences were found.

Similar results and transformation pathways were found by Gulagi et al. [21,47]. Comparing the country-wide scenario by Gulagi et al. [47] to our 100% RES scenario, a moderate phase out of coal and fast expansion of solar PV and onshore wind can be observed. While India's power generation is dominated by coal in 2015, solar PV establishes itself as the key technology by 2050, followed by onshore wind and biomass [47]. Differences in absolute values can be traced back to the ability of GENeSYS-MOD to also include the heat and transport sector.

4.2. Regionalization of Scenario Results

The analysis of the regional supply mixes reveals significant differences (see Appendix B). In the LEO scenario in 2050, solar is the dominant source of supply in all regions, except for two: the north and the NE, both mountainous regions with a lot of hydropower. Onshore wind is most prominent in the west and the south, whereas offshore wind occurs hardly anywhere.

Starting from 2020, solar capacities heavily increase in all regions, whereby CE and UP are relying nearly solely on solar power in the final year. The north and NE regions exhibit the highest hydro potentials and account for about 64% of India's total hydropower generation.

In the LEO scenario, coal electrification is mainly concentrated in UP in 2050 (26%). The nodes CW (2%), NW (5%), south (3%), and west (6%) play a minor role. With relatively modest wind resources, UP is the only state that uses natural gas electrification.

All scenarios have a similar regionalization of energy sources. However, more conventional fuels are used in the BAU scenario, especially in the NW region (21%). In the 100% RES scenario, all regions are relying on RES with a similar distribution as the LEO scenario, substituting the conventional energy sources in the south-west, south-east, and UP with RES and electricity imports.

4.3. Energy System Cost and Long-Term Electricity Prices

Given that the energy mix between the three scenarios is not very different, it is not surprising that the energy system costs are quite similar as well. With the BAU scenario having the lowest discounted costs over the whole model period, it shows that feeding demand in the high-temperature heat and freight transportation sectors based on power-based technologies is more cost-intensive than using fossil fuels, especially in the case of high shares of RES. Although it might be the cheapest, external cost and effects on the environment that are difficult to be quantified need to be kept in mind. In comparison, the LEO scenario comes to a result with slightly higher costs (about 2%), while the 100% RES scenario results in 9% higher total discounted costs than the BAU scenario.

The average costs of electricity generation within the model will decline from 7.5 €cents/kWh in 2015 to less than 3 €cents/kWh in 2050 in the LEO scenario. However, infrastructure and transportation costs are not included. Nevertheless, variations in the power generating costs between the technologies can be observed and depend on the different operational lifetimes, operational and maintenance costs, as well as capital and fuel costs. Within the model, coal-based electricity ranges from 3.3 to 3.7 €cents/kWh. These costs are currently lower than the daily updated data of the Ministry of Power [52], as they do not include the costs for infrastructure. Apart from that, renewable technologies will become increasingly competitive, with solar and wind power observing the biggest reduction of power generating costs over time, which drive coal-based generation out of the market. Utility-scale solar power lies in the range of 1.3–2.8 €cents/kWh for power generation, with wind power ranging from 3 to 5 €cents/kWh. At the same time, hydro power shows up with 2–3 €cents/kWh for electricity generation within the model. Regarding the projections of Bloomberg New Energy Finance [53], similarities can be observed as there will be a tipping point where coal will be replaced by cheap renewable options. In between the regions of India, prices can vary up to 50%, which can be traced back to different capacity factors and full load hours of generation facilities. While different climate targets do play a role in the energy mix, their overall economic effects seem to be modest.

5. Barriers to the Low-Carbon Energy Transformation in India

As seen in the previous sections, renewable energy technologies have an enormous potential in India and a 100% RES based energy system in 2050 can be achieved. However, experience shows that economic theory and reality do not always match. An assessment of present literature and expert interviews aims to contextualize the low-carbon energy transformation and the model results within the social, political and economic contexts. The low-carbon transformation of the energy sector is not solely driven by climate consideration, but is inserted into a complex process of sustainable development that includes (amongst others) reducing health risk, affordable energy and a circular economy. In order to make an evaluation about whether the country is truly able to become 100% RES-based in 2050, further implications on India's energy transformation have to be considered. Based on this literature review, those factors can be divided into social, political, and economic barriers.

5.1. Social Barriers

In acknowledgement of the complexities associated with the low-carbon transformation in India, it is important to contextualize the transition against the overall economic situation of the broader population. India, having a GDP per capita of 1974.76 USD [54], a high share of its population living in extreme poverty, and a rapid urbanization, economic growth is often perceived as more pressuring than investment into green development projects [27].

Currently, there are still more than 300 million people with no access to electricity [8]. Consequently, environmental standards for power plants are perceived as barriers to economic growth. A prime example for this is the protest against higher environmental standards in 2014 by the population of Vapi, one of the most polluted cities in India [55]. This can mainly be explained by the cities' dependence on its large and highly-polluting pharmaceutical and chemical industries and the public fear of losing much-needed jobs and capital [26].

A low-carbon transition as planned by governmental motivations, however, holds various opportunities for further economic growth in green industries—despite the rate of employment in the coal industry decreasing constantly since 2002 [37]. Especially in regard to the enormous solar potential and the ambitions to extend the national capacities in wind and solar (see Section 2.2.1), it could generate up to 330,000 jobs over the next five years, i.e., in manufacturing, project design, construction, business development, and operations and maintenance [56]. Changing the perception of the low-carbon transition as a barrier for economic growth by educational work and improving social circumstances is thus crucial for a successful energy transformation.

5.2. Political Barriers

A significant barrier to the increase in RES are lobbies of the conventional energy sector. The coal industry still meets most of India's energy demand and employs over 400,000 people. Their businesses include rail, port, and road transport, loading and unloading, as well as the power plants (see Section 2.1). In addition, a substantial portion of the coal-mining sector is dominated by the state-owned company CIL. A possible depletion of coal mining would therefore have a negative influence on the government's budget. Consequently, past and current Indian governments have been pushing the expansion of the coal mining sector and plan to increase the annual production from a current level of 600 million tons to 1.5 billion tons in 2020 [26].

Not only external factors are of importance for the implementation of policies in a country. Internal factors, such as the lack of coordination and cooperation within and between various Indian institutions and other stakeholders, slow down and restrict the transformation to RES. Currently, multiple agencies (i.e., the Federal Ministry for New and Renewable Energy, Ministry of Power, Department of Environment and Forests, Department of Rural Development, as well as corresponding agencies in each state) have overlapping areas of responsibilities regarding renewable energy. A good example of this lack of coordination is the implementation of the generation based incentive (GBI) for solar power, a scheme provided to, among other things, "support small grid solar power projects connected to the distribution grid (below 33 KV) to the state utilities" [57]. Soon after its announcement by the Ministry of New and Renewable Energy (MNRE), the Indian Renewable Energy Development Agency (IREDA) started accepting applications for solar projects under the GBI scheme. Later, however, the Indian government rejected all applications that were made before the official announcement of the scheme through the federal gazette [58]. While this reaction is justified and the IREDA should not have accepted applications in advance, it is this lack of coordination between institutions that complicates the implementation of policies and discourages investors.

Furthermore, there are currently two policy narratives for the development of the Indian energy system: the centralized approach, in which the Indian government mainly pushes for the integration of renewables through a unified power grid, and the former being decentralized, providing basic energy access using off-grid solutions [59].

5.3. Economic Barriers

The fact that India's energy demand is predicted to increase heavily until 2050 forms one of the biggest challenges in its low-carbon transformation. The growth can be traced back to the increasing electricity access, especially in rural areas, and to urbanization. Lifestyle and dietary changes, i.e., increasing demand for meat, dairy products, and luxury goods are all factors which contribute to India's growing energy consumption [60]. Growing electrification in the agricultural sector, and more reliable energy supply for industry and highly populated areas, are coupled with India's economic growth. Merging those interactions represents a challenge for the energy system. Within the model results, India's electricity generation is estimated to increase by a factor of ten from 2015 to 2050, whereby the analysis shows that renewable energy potentials are sufficient. Correspondingly, Bhushan [8] points out that the organization of the distribution systems needs to be tackled. Thus, an ambitious increase in power-generating capacity and change towards renewable technologies on a large scale is necessary to ensure a sustainable power supply.

In general, renewable energy projects tend to have little or no fuel, operating, or maintenance cost, but their relative initial investment costs tend to be much higher than for those of conventional energy systems [58]. Renewables in India are often around 24–32% more expensive compared to similar projects financed in the US or Europe. Indian financial market conditions are the main cause of high interest rates for renewable energy. Growth, high inflation, and country risks all contribute [61]. Therefore, by requiring these large-scale upfront investments, renewable energy projects are reliant on long-term investors [27].

It has been difficult, however, to attract those long-term investors for a multitude of reasons. First and foremost, India's legal and regulatory system is often viewed as uncertain and risky, as manifested in various forms like changes in tax codes, a lack of protection for policy changes and enforcement of contracts [27]. Furthermore, there is a deficiency in information about renewable energy projects, as well as the value of different companies. That information, however, is crucial for the analysis and decision-making of investors.

India's losses in the transmission and distribution (T&D) power grid are one of the highest worldwide, with a total share of 19.4% [62]. Those high T&D losses are an additional consequence of the widespread power theft, illegal hook-ups, and a low payment morale [63]. Agriculture users in particular pay for less energy than they consume [63]. Regarding the model results, a 100% RES-based power supply is only feasible if regions can compensate imbalances in RES potentials through an efficient power exchange. A sensitivity analysis showed that a decrease down to 5% of losses ensures a feasible power supply for all regions in the 100% RES scenario. Overcoming this technical challenge through promoting investments forms one of the biggest hurdles in the low-carbon transformation for India.

To finance large-scale investments, private investors could impact the velocity of the transformation within the energy system. Considering the current share of 6.7% private players in the transmission network, it stands out that the regulatory framework is still not exhausting the full financing potential through private contributions. The "Doing Business" ranking by The World Bank underlines those circumstances, whereas India is on rank 185 in "Dealing with Construction Permits" and on rank 172 in 'Enforcing Contracts' out of 190 economies by comparison [64]. For that reason, the government is encouraging private investments. Financial mechanisms and policy frameworks for a faster commercialization of renewable energy technologies are analyzed by Balachandra et al. [65].

Currently, increasing attention is given to off-grid technologies, such as solar rooftops with battery back-ups to achieve energy access to all regions. This also concerns households in highly populated areas to become independent from local network operators [8]. Despite the high willingness to invest in off-grid technologies, low-income households still need to be addressed [66]. Within the National Electricity Plan, 40 GW of solar rooftops are planned to be installed by March 2022 to relieve the local power grids [2].

Regarding the model, the results of all three scenarios visualize that the most economically viable energy path leads to an energy mix dominated by solar. With a total share of 68% of solar energy in power generation, India will become a solar reliant country in 2050, which consequently takes risks within. Especially in times when solar power generation is very low, security of energy supplies is difficult to ensure. Considering the concentrated energy demand in conurbations (like UP), on the other hand, makes clear that a sufficient power supply can only be reached if the power system gets optimized. Therefore, storage technologies play a significant role to compensate for fluctuating energy generation.

6. Conclusions

With 6% of global GHG emissions and a predicted future increase, India plays a determining role in future climate policies. In this paper, we explore energy pathways for India from 2015 to 2050 by applying the GENeSYS-MOD to different scenarios. The model results of the LEO scenario visualize the future importance of solar energy within the low-carbon transformation. Even without setting a strict restriction for using conventional energy sources in 2050, renewables (especially solar) will satisfy almost the whole energy demand in 2050, whereas conventional sources will have a negligible share of 2.8% (mainly located in densely populated regions, e.g., UP). In 2050, the share of solar takes over 67% of the whole power production, followed by wind (23%) and hydropower (6%) in the LEO scenario.

For progressive planning, crucial circumstances have to be kept in mind. First of all, India as a developing economy is facing an increasing demand in power, and energy access is an ongoing issue, especially in rural areas [2]. Furthermore, within the conventional energy sources, the future of coal electrification depends on market design, the implementation of existing environmental norms, and regional development perspectives in affected areas. Apart from that, the recent growth of utility-scale solar needs to be accompanied by distributed solar (and batteries), both at the urban and the rural level, to become sustainable and extend the rural electrification progress. As current plans are perceived to be achieved before 2025, set goals submitted in the INDCs and the current Five-Year Plan are assessed as not ambitious enough. Moreover, it is illustrated within the BAU scenario that current electricity plans of the Indian government diverge from needed requirements to contribute to the global rising limit of 2 °C to pre-industrial levels. Tightening the government's goals until 2030 would consequently both counterbalance and reduce the total cost of the path from there on to 2050, which is projected to be a largely renewable energy-based system. Consequently, fulfilling the Paris Agreement will require stronger efforts in India's current policies, especially in the last two decades leading up to 2050 in comparison to a smoother and more cost-efficient increase of RES over time. While the model incorporates a high level of detail on a multitude of technologies, inter-sectoral-connections, and the resulting energy mix, its rather rough time disaggregation has to be noted. Variable renewable energy (VRE) technologies and their inherent unstableness, creating a need for flexibility options such as storage, might require a more detailed distinction between time slices. Future research should focus on how to implement such an assessment for even more detailed data on the different sectors and the effects of variable RES on the electricity system.

A reduction of the losses and tackling power theft within the power trade would ensure an efficient overcoming of imbalances in between the regions of different renewable energy potentials. Making up leeway in the transmission grid sector is one of the important actions. The results for the 100% RES scenario illustrate the cost-optimized pathway towards 2050 for a technically feasible energy system based on 100% RES, a finding which has been shown by Gulagi et al. [21,47] independently. Additionally, the difference between the LEO and 100% RES scenario in the use of conventional sources indicates that a 100% renewable energy supply is an ambitious goal for 2050. Noticing the negligibly higher total cost of an energy system based on 100% RES to the LEO benchmark or the BAU scenario, this goal may be ambitious but not impossible to achieve.

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Appendix A. Model Parameters

Table A1. Regional electricity, high and low heat demand in PJ.

Region		2015	2020	2025	2030	2035	2040	2045	2050
Annual electricity demand (PJ)	North	136.51	173.39	220.25	279.76	355.36	451.38	573.35	728.28
	NW	700.57	889.87	1130.33	1435.77	1823.73	2316.53	2942.50	3737.60
	West	620.66	788.38	1001.41	1272.01	1615.72	2052.31	2606.88	3311.30
	CW	627.82	797.46	1012.95	1286.67	1634.35	2075.97	2636.93	3349.47
	CS	590.04	749.47	951.99	1209.24	1535.99	1951.04	2478.24	3147.90
	South	440.51	559.55	710.74	902.80	1146.75	1456.62	1850.22	2350.17
	East	319.53	405.87	515.54	654.85	831.80	1056.57	1342.07	1704.72
	CE	153.64	195.15	247.89	314.87	399.95	508.03	645.31	819.68
	NE	53.42	67.86	86.19	109.48	139.07	176.65	224.38	285.01
	UP	373.60	474.55	602.78	765.66	972.55	1235.35	1569.16	1993.18
∑		4016	5102	6480	8231	10,455	13,280	16,869	21,427
Annual high heat demand (PJ)	North	217.00	302.10	373.46	444.83	503.68	562.53	635.46	708.39
	NW	1113.65	1550.38	1916.63	2282.88	2584.92	2886.96	3261.23	3635.50
	West	986.63	1373.55	1698.02	2022.50	2290.09	2557.68	2889.26	3220.84
	CW	998.00	1389.38	1717.60	2045.81	2316.49	2587.16	2922.57	3257.97
	CS	937.95	1305.77	1614.23	1922.70	2177.09	2431.47	2746.69	3061.91
	South	700.26	974.87	1205.16	1435.46	1625.38	1815.30	2050.63	2285.97
	East	507.94	707.13	874.17	1041.22	1178.98	1316.74	1487.44	1658.15
	CE	244.23	340.01	420.33	500.65	566.89	633.13	715.21	797.28
	NE	84.92	118.22	146.15	174.08	197.11	220.14	248.68	277.22
	UP	593.88	826.78	1022.09	1217.41	1378.48	1539.55	1739.14	1938.73
∑		6384	8888	10,987	13,087	14,819	16,550	18,696	20,841
Annual low heat demand (PJ)	North	262.70	274.70	265.05	255.40	233.99	212.58	206.48	200.37
	NW	1348.19	1409.77	1360.26	1310.74	1200.86	1090.99	1059.65	1028.31
	West	1194.42	1248.97	1205.11	1161.24	1063.90	966.55	938.79	911.03
	CW	1208.19	1263.37	1219.00	1174.63	1076.16	977.69	949.61	921.53
	CS	1135.48	1187.34	1145.64	1103.94	1011.40	918.86	892.46	866.07
	South	847.73	886.45	855.32	824.18	755.09	686.00	666.30	646.59
	East	614.91	642.99	620.41	597.83	547.71	497.60	483.31	469.01
	CE	295.67	309.17	298.31	287.45	263.36	239.26	232.39	225.51
	NE	102.81	107.50	103.73	99.95	91.57	83.19	80.80	78.41
	UP	718.96	751.80	725.39	698.99	640.39	581.80	565.09	548.38
∑		7729	8082	7798	7514	6884	6254	6074	5895

Table A2. Regional demand for transportation in Gpkm (passenger) and Gtkm (freight).

Region		2015	2020	2025	2030	2035	2040	2045	2050
Annual demand for passenger transportation (Gpkm)	North	49	71	89	107	126	145	164	183
	NW	252	364	458	552	647	743	841	940
	West	223	323	406	489	573	658	745	832
	CW	226	326	410	494	580	666	754	842
	CS	212	307	386	465	545	625	708	791
	South	158	229	288	347	407	467	529	591
	East	115	166	209	252	295	339	384	429
	CE	55	80	100	121	142	163	184	206
	NE	19	28	35	42	49	57	64	72
	UP	134	194	244	294	345	396	449	501
∑		1443	2087	2625	3162	3710	4258	4822	5386
Annual demand for freight transportation (Gtkm)	North	26	38	48	58	68	78	88	99
	NW	136	196	247	297	349	400	453	506
	West	120	174	219	263	309	355	402	449
	CW	122	176	221	266	313	359	406	454
	CS	114	165	208	250	294	337	382	427
	South	85	123	155	187	219	252	285	318
	East	62	90	113	136	159	183	207	231
	CE	30	43	54	65	76	88	99	111
	NE	10	15	19	23	27	31	35	39
	UP	72	105	132	159	186	213	242	270
∑		778	1125	1415	1704	2000	2295	2599	2903

Table A3. Regional capacity factors for solar PV, onshore and offshore wind. WN = winter night, WD = winter day, SN = summer night, SD = summer day, IN = intermediate night, ID = intermediate day.

Region		WN	WD	SN	SD	IN	ID
Solar PV	North	0.00	0.25	0.00	0.30	0.00	0.28
	NW	0.00	0.27	0.00	0.29	0.00	0.30
	West	0.00	0.30	0.00	0.24	0.00	0.30
	CW	0.00	0.32	0.00	0.23	0.00	0.29
	CS	0.00	0.35	0.00	0.22	0.00	0.28
	South	0.00	0.49	0.00	0.29	0.00	0.39
	East	0.00	0.32	0.00	0.21	0.00	0.31
	CE	0.00	0.28	0.00	0.26	0.00	0.30
	NE	0.00	0.32	0.00	0.21	0.00	0.31
	UP	0.00	0.32	0.00	0.21	0.00	0.31
Onshore wind	North	0.32	0.19	0.37	0.20	0.35	0.24
	NW	0.32	0.12	0.48	0.30	0.26	0.12
	West	0.28	0.17	0.36	0.42	0.22	0.13
	CW	0.25	0.14	0.43	0.57	0.20	0.14
	CS	0.27	0.13	0.44	0.52	0.20	0.13
	South	0.17	0.14	0.29	0.46	0.12	0.13
	East	0.23	0.09	0.33	0.29	0.20	0.14
	CE	0.24	0.16	0.19	0.17	0.24	0.21
	NE	0.33	0.17	0.24	0.20	0.36	0.24
	UP	0.27	0.15	0.20	0.17	0.31	0.19
Offshore wind	NW	0.19	0.34	0.49	0.52	0.19	0.27
	CW	0.14	0.22	0.47	0.42	0.15	0.13
	CS	0.08	0.17	0.39	0.37	0.10	0.10
	South	0.36	0.39	0.61	0.58	0.23	0.29

Appendix B. India's Regional Electricity Production

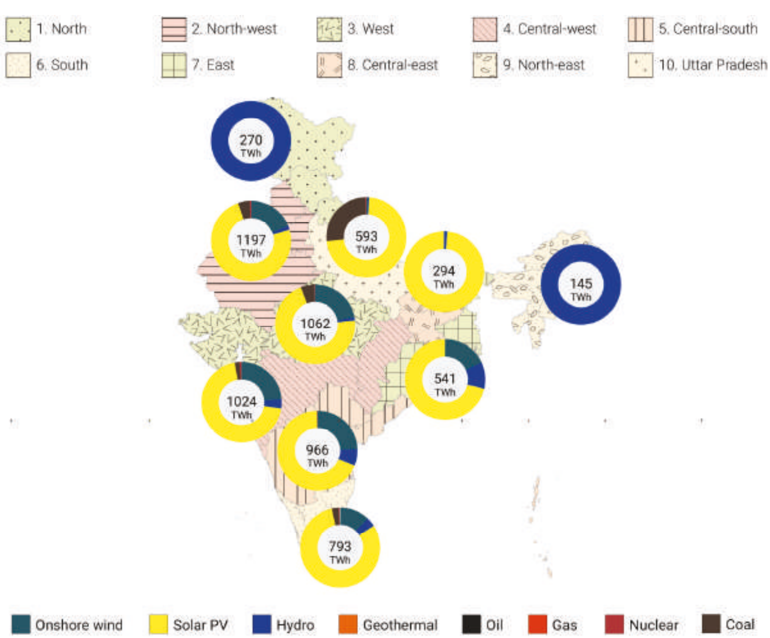

Figure A1. India's regional electricity production in the benchmark (LEO) scenario (2050).

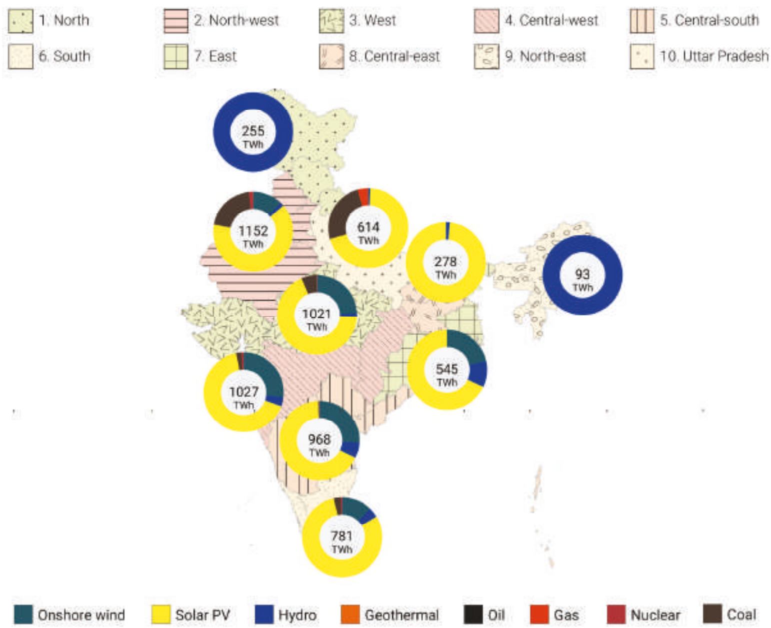

Figure A2. India's regional electricity production in the BAU scenario (2050).

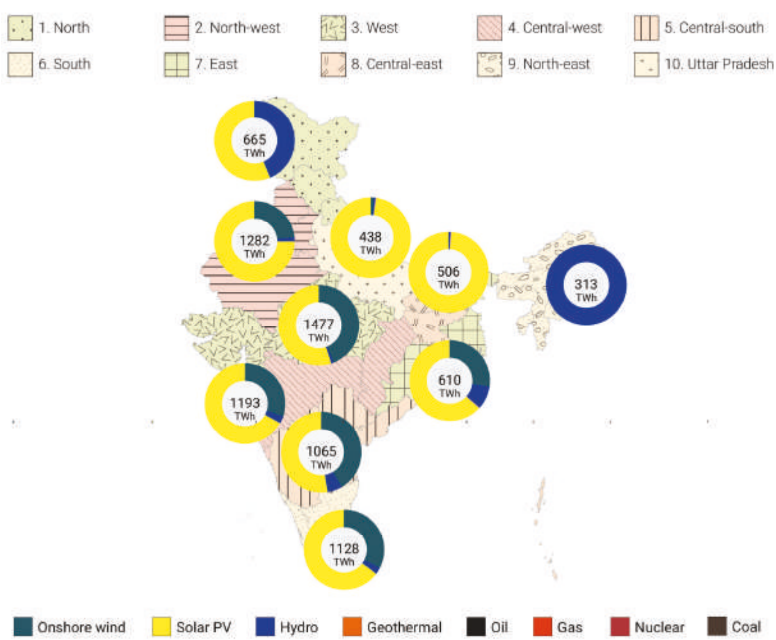

Figure A3. India's regional electricity production in the 100% RES scenario (2050).

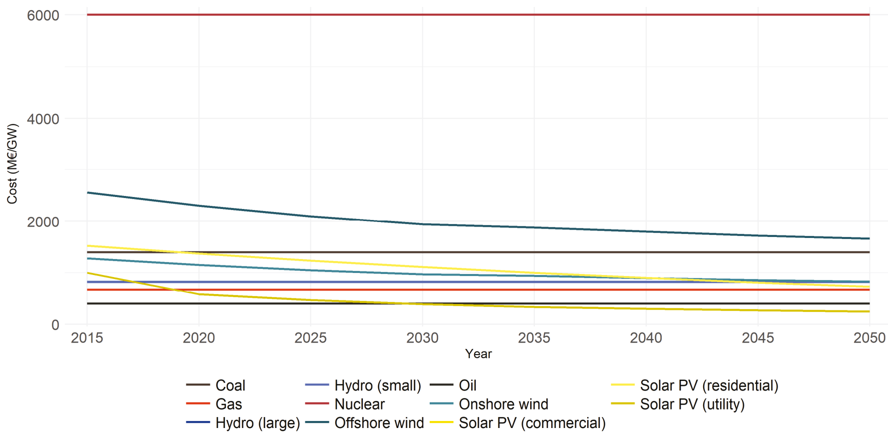

Figure A4. Capital cost development of electricity-generating technologies in million €/GW.

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Article

Analyzing Scenarios for the Integration of Renewable Energy Sources in the Mexican Energy System—An Application of the Global Energy System Model (GENeSYS-MOD)

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Abstract: This paper uses numerical techno-economic modelling to analyse the effect of current national renewable targets and climate goals on the cost and structural composition of the Mexican energy system. For this, we construct a scenario base analysis to compare current policies with two alternative states of the world—one without climate policies and one attaining full decarbonization. Furthermore, an additional iterative routine allows us to estimate the cost-optimal share of renewable technologies in the energy sector and the effect that deviating from this share has on total discounted system costs, emissions and the structure of the energy mix. In general, model results exhibit three key insights—(1) A marked dependence of the energy system on photovoltaics and natural gas; (2) The 2050 cost-optimal share of renewables for the production of electricity, transportation and industrial heating is respectively 75%, 90% and 5%; and (3) As national renewable targets for the power sector are lower than the cost-optimal share of renewables, equivalent to the shares in an scenario without climate policies and completely disconnected from national climate goals, these should be modified.

Keywords: renewable transition; numeric modelling; Mexico; climate policies; energy transition; energy policy; GENeSYS-MOD

1. Introduction

Examining the cost and structure of energy systems under different decarbonization policies is an essential scientific exercise to understand the consequences of current renewable targets and climate goals on future energy outcomes. Policies seeking to decarbonize the energy sector are a response to the adverse effects of human emissions of environmental contaminants and greenhouse gases (GHGs) imposed on the planet, society and individuals, such as climate change [1–3], loss of biodiversity [4,5], adverse health outcomes [6–8] and productivity shocks to labour supply [9–12]. The National Aeronautics and Space Administration (NASA) states that climate change is likely to continue throughout this century, with changes in harvesting seasonality, variation in precipitation rates, an increasing number of droughts, stronger heatwaves, bigger hurricanes and higher water levels [2].

In the first United Nations Framework Convention on Climate Change (UNFCCC), the majority of national governments acknowledged the substantial evidence in favour of human-made climate change and, at the first conference of the parties (COP1), the Kyoto protocol was signed [13]. The Kyoto protocol was the first collective agreement to recommend a decrease in GHG emissions and, since then, serves as the cornerstone for all intergovernmental negotiations regarding climate change and mitigation of anthropogenic emissions. In 2015, during the 21st conference of the parties of the UNFCCC (COP21), 195 national governments, including Mexico, signed the Paris Agreement, a collective arrangement to hold global warming below two degrees Celsius. However, even though there is a common understanding to reduce anthropogenic emissions, each nation is independently developing its own mitigation strategies. Among these strategies are the introduction of national renewable targets for increasing the percentage of renewables in the energy sector and climate goals for decreasing national anthropogenic emissions. In Mexico, there is a general climate objective that goes hand in hand with the Paris Agreement. The law sets the aspirational goal to reduce emissions by 50% in 2050 (base year 2000). Furthermore, the country also has renewable targets aiming to generate 50% of its power through renewable production in 2050. This study aims to analyze not just the effect of current renewable targets and climate goals in the Mexican energy sector but also how these policy instruments deviate from two alternative scenarios: one without climate policies and another with full decarbonization. For this, we optimize the energy sector using the Global Energy System Model (GENeSYS-MOD), a bottom-up techno-economic model developed by Löffler et al. [14]. Techno-economic energy system models, like GENeSYS-MOD, can assist policymakers by providing unbiased assessments on the effects of different policies on future energy outcomes. Specifically, these models allow modelers to infer the consequences of different climate policies in the cost, structure and composition of the energy mix. Although the name of the model suggests a global approach, the application to specific regional energy sectors is possible. In this case, we apply the model to Mexico, using a regional extension of the global data set and warn the reader about the potentially misleading nature of the name.

The primary objective of this optimization study is to answer four questions: first, how do costs and power mixes change in response to variations in energy and climate policies? Specifically, what are the effects of current renewable targets and climate goals *vis-a-vis* a scenario without the implementation of climate policies and another attaining full decarbonization. Second, what is the 2050 cost-optimal share of renewables in the Mexican energy mix for the power, heating and transportation sectors? Third, what is the marginal cost increase in each sector resulting from deviating from cost-optimal renewable targets? And fourth, are the climate goals and renewable targets aligned and how much do these deviate from the full decarbonization and policy free scenarios? To answer these questions we use four different scenarios —BAU, National Targets, Climate Goals and 100 percent Renewables—plus a iterative optimization routine of the Mexican energy system. We answer the first question by comparing all four scenarios, allowing us to contrast current public policies for the introduction of renewables or the reduction of emissions with the two additional scenarios (BAU, and 100 percent Renewables). To answer the second and third questions, we use an iterative optimization routine consisting of 20 different scenarios under increasing and binding renewable targets. In each optimization, the share of renewables in the system increases from 0% to 100% in 5% intervals. After each optimization, we calculate total discounted system costs and, with this information, determine the cost-optimal share of renewables in the energy system and the marginal cost of deviating from this optimal share. Finally, to answer the last question, we compare the effect of current National Targets and Climate Goals between them and with BAU in order to infer the alignment between both goals and their specific effect in the system. This article is, to the best of our knowledge, the first techno-economic model looking at the optimal cost-share of renewable technologies and the associated costs of deviating from this optimal in the transportation, heating and power sectors while accounting for sector coupling.

The following list presents a detailed explanation of the four main scenarios and the iterative routine:

- *BAU*: the model has no requirements regarding renewable targets or climate goals.
- *National Targets*: the model has to comply with current renewable targets in the power sector: 25% by 2018, 35% by 2024 and 50% by 2050 (Mexico defines these targets for clean energies (including nuclear as well as carbon capture and storage facilities). However, to stay in line with international comparisons, this paper defines clean energies as only those related to traditional renewable technologies.) [15]. Additionally, Renewable targets are only set for the power sector and all Mexican states should jointly achieve them. This cooperation means that renewable-rich regions can export their renewably produced surplus to other parts of Mexico.
- *Climate Goals*: the model has to comply with current climate goals for the reduction of GHG emissions: 30% by 2020 and 50% by 2050 [16]. The climate objectives are defined on the national level across all sectors and regions of the economy. The model minimizes costs across all sectors with the underlying goal of achieving the necessary reductions in greenhouse gas emissions.
- *100 percent Renewables*: the model has to reach full decarbonization of the energy system by 2050.
- *Iterative routine*: The model runs 20 different optimization routines by assuming 20 different renewable shares. The share of renewables in the system starts at 0% and linearly increases in 5% intervals until it reaches 100%. At each iteration, the model is required to comply with the renewable share without exceeding it.

Analyzing the Mexican energy system is interesting for several reasons. First, Mexico is one of the largest greenhouse gas emitters (13th) [17], oil producers (11th), electricity producers (13th), electricity consumers (15th), natural gas consumers (9th) and oil consumers (10th) in the world [18]. Second, the country has a high potential for the deployment of renewable technologies, like solar and wind, with respective potential capacities of 1172 and 583 gigawatts [19]. Third, the geographical location of the country opens the possibility of further integrating its electricity system with the United States and Canada, forming an integrated North American energy market, which would be one of the largest in the world.

Currently, the Mexican energy mix is heavily reliant on fossil fuels. Figure 1 (left) plots the input share of each energy carrier in the mix. As can be seen, the system heavily relies on oil to satisfy its energy demands. Regarding the sectoral composition of the energy system, Figure 1 (right) illustrates that the transportation sector is responsible for the highest share of demand for energy in the country.

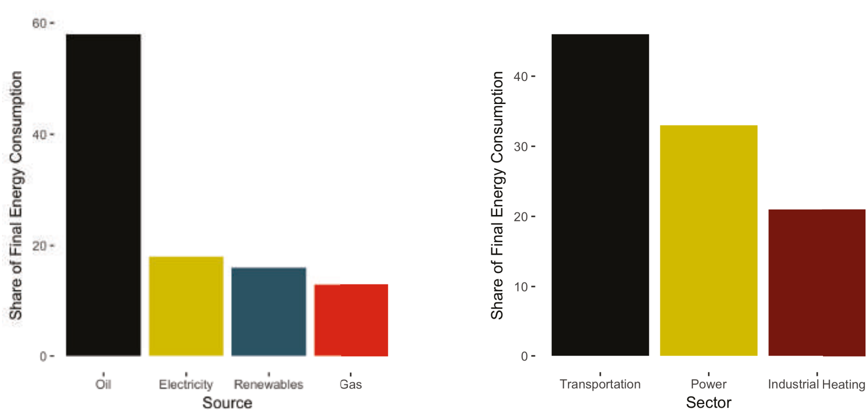

Figure 1. Percent Share of Final Energy Demand for Sources and Sectors.

Figure 2 plots the fuel and technology mix of the demand for energy in each sector. Industrial heating heavily relies on natural gas, transportation on oil and the generation of electricity on thermometric, carboelectric and hydroelectric power plants. Specifically, natural gas has increased its share in the energy mix because of steady increments in the national demand for electric power and drops in the price of natural gas due to fracking activities in the United States (see Wang et al. [20]) that push oil away from the energy demand in the power and heating sectors. In 2002, natural gas was responsible for 37% of national capacity and 46% of electricity generation. By 2015 these shares had grown to 49% and 53% respectively. In general, 81% of all required new capacity between 2002 and 2015 came from natural gas power plants.

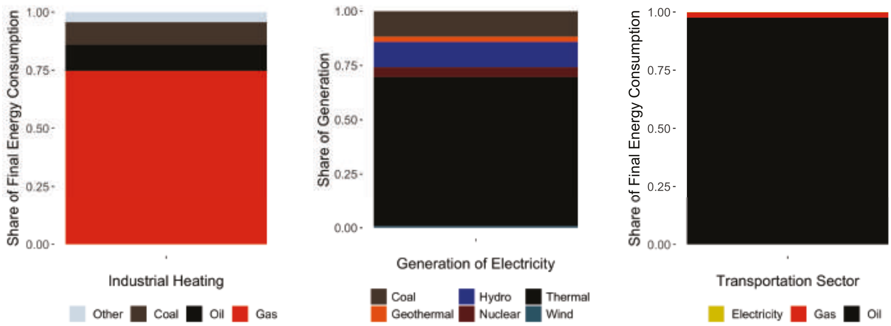

Figure 2. Fuel and Technology Composition of the Heating, Power and Transport Sectors.

In 2015, the country consumed 288,232 GWh of electric power. It reached minimum demand on 1 January, at 18,341 MWh/h and maximum on 14 August, at 39,840 MWh/h. Higher demand for electric power comes in the summer months and afternoons due to the use of air conditioning and cooling technologies. This peak demand coincides with periods of high solar radiation when photovoltaic facilities can produce more power but is counter-cyclical to the production of wind and hydroelectric technologies. Figure 3 plots the intraday behaviour (load curve) of the national electric system for an average winter and summer day.

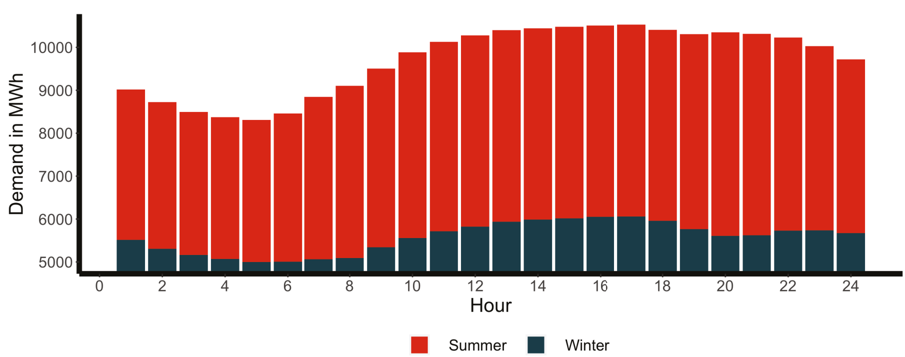

Figure 3. Load profile of the Mexican electric system.

The industrial heating sector (the heating sector consists of residential and industrial heating. However, due to its geographical location, Mexico has no relevant demand for house heating) has no available public information on its energy demand. However, data on total energy and electricity demand at the industry level is publicly available [21]. Using this information, under the assumption that industrial demand for energy comprises electricity and heating and then combining it with the gross domestic product estimates of each industry at the state level [22], allows us to create an approximated value for the demand for heat in each control region. Imputed values show an aggregated heating demand in 2015 of 1060 Petajoules (PJ). The industries contributing most to this share are steel, cement and chemical at 18%, 12% and 13%, respectively.

The national center for energy control (CENACE) divides the country into nine different regions. The model uses these regions to optimize the Mexican energy system. However, the regions of the model are slightly different than the regions of CENACE as the datasets with energy information come at the state level and the regions of CENACE are defined at the municipality level. Figure 4 maps each region into the map of Mexico and plots their respective installed capacity (for more information about the regional disaggregation, see Appendix A).

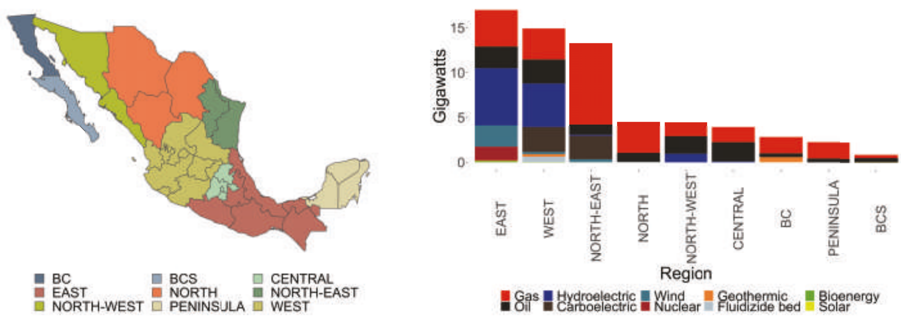

Figure 4. Modelled regions and Installed Capacity per Region.

The rest of this article is structured as follows: Section 2 describes the data sources. Section 3 provides a historical review of numerical models in energy markets, explains the structure and characteristics of GENeSYS-MOD and outlines some related literature. Section 4 presents the results of the model and Section 5 concludes, summarizing the main findings.

2. Data

Numerical models of energy systems require large quantities of information on the electric, transportation and heating sectors to provide accurate estimates on the behaviour of the whole energy sector. For the Mexican power sector, capacity and generation data come from the Energy Information System of the energy ministry [21] and the North American Cooperation on Energy Information System [23]. Data on the potential for renewable sources is taken from the National Atlas for the Assessment of Areas with High Renewable Potential [19] and the National Inventory of Clean Energies of the Energy Ministry [24]. Load profiles per state, nodal structure and transmission capacities come from citizen requests to the National Center for Energy Control. Finally, planned mid-term improvements to the transmission grid originate from the National Electric System Development Program 2017 [25].

Transportation data on the number of cars, buses, trains, passengers and cargo, as well as the length of highways, railways and motorways and total energy consumption was obtained from the Ministry of Transportation and Communications statistics portal [26].

For industrial heating, unfortunately, there is no publicly available data on the exact demand in each region. However, we impute the regional demand with the following method. We assume that national consumed energy by the industrial sector (δ_{st}) is the sum of electricity (ϕ_{st}) and heat consumption (γ_{st}): $\delta_{st} = \phi_{st} + \gamma_{st}$. (The data on energy and electricity consumption may disregard production or transportation losses. Unfortunately, there is no available information on the accountability process with which the government reached these figures. To determine the demand of industrial heat in each state we thus assume the following. All three: total consumed energy, power and heat are subject to a losses of the form $\delta_{st} - \hat{\delta_{st}} = (\phi_{st} - \hat{\phi_{st}}) + (\gamma_{st} - \hat{\gamma_{st}})$, where the hat above the variable indicates the aggregate of transmission, production and efficiency losses. By a simple exercise, we can see that $\delta_{st} = \phi_{st} + \gamma_{st} - (\hat{\phi_{st}} + \hat{\gamma_{st}} - \hat{\delta_{st}})$ which can be simplified to $\delta_{st} = \phi_{st} + \gamma_{st} + \epsilon_{st}$. The main assumption of this estimation is that $\epsilon_{st} \sim 0$ or equivalently $\hat{\phi_{st}} + \hat{\gamma_{st}} = \hat{\delta_{st}}$.) The national system of energy information provides national data on the first two elements: industrial consumed energy and electricity. This information allows us to determine the national demand for industrial heat. Once we obtain the national demand for industrial heat, we use additional segregated national data on national energy and power demand per industry to determine the share of the national heating demand that accrues to each industrial sector. Then we use data from the 2015 economic census of the national institute of geography and statistics (INEGI) to calculate the share of each industry in each state and, thus, the demand for heat that accrues to each state. For example, if the national heating demand of the cement industry is 6.816 PJ and if 50% of the national gross domestic product of the cement industry belongs to a specific state, this state will also have 50% of the total demand (3.408 PJ). Concerning additional inputs, Table 1 summarizes the main sources and assumptions. Fore additional input data, please refer to Appendix B.

Table 1. Key sources for demand and technology data.

Variable	Source
Energy and power demand	PRODESEN [25]
Demand for energy in transport	SCT [26]
Demand for energy in high temperature heating	Own calculations based on data from SENER [21]
Forecast for energy demand	PRODESEN [25] and linear growth based on GDP and population forecasts.
Power plant capacities in 2015	Global Power Plant Database and PRODESEN [25]
Capacity factors of RES	renewables.ninja, see Pfenninger and Staffell [27]
Potential of RES	Solar: own assessment based on capacity factors, available, usable, area and conversion efficiencies. Hydropower and Wind: SENER [19] Geothermal: Gerardo Hiriart Le Bert [28]
Fuel prices	SENER [21] and International Energy Agency [29]
Remaining technology data	Carlsson et al. [30], Basis [31], Gerbaulet and Lorenz [32], Ram et al. [33] and Burandt et al. [34]

Notes: The following table summarises the main data sources of the model. **Acronyms:** PRODESEN: National Program for the development of the electric system—SCT: Ministry of Transport and Communications—GDP: Gross domestic product—SENER: Energy Ministry.

3. Model

Numerical models of energy systems use a system of equations to simulate the consequences that exogenous shocks and different states of the world have on the overall structure of the energy sector. The necessity for this kind of model originated in the acute effects experienced by oil-dependent industrialized countries during the 1970s oil crisis. The oil crisis increased the necessity to simulate the behaviour and reliability of energy markets under exogenous supply and demand shocks [35]. After the development of these oil models, there was a steady change in scope to incorporate climate change, pollution and other relevant externalities from the energy sector. Traditionally, these new energy models analyze the interdependencies and optimal shares between the three main sources of primary energy: fossil fuels, nuclear and renewables. However, recent debates regarding the possibility of fully decarbonized energy systems (Clack et al. [36], Jacobson et al. [37], Hansen et al. [38], Geels et al. [39]) and the availability of low-cost storage technologies shifted interest to the analysis of decarbonization paths and the future development of green energy operations.

Overall, numerical models can be broadly divided into techno-economic and macroeconomic models [35]. Techno-economic models permit separating the energy system into different technologies, processes and interdependencies across energy carriers. This ability to divide the energy system into smaller technology blocks allows the model to internalize the impact of specific policies in each subdivision and to play with the relationships between sectors, technologies and regions.

Macroeconomic models, on the other hand, account for the economic determinants behind energy systems. They experience a trade-off between technical detail and economic insights while attempting to capture links between the energy sector, the economy and society. The separation between techno-economic and macroeconomic models resulted in the need to develop a new set of models that internalize the advantage of both approaches. For example, computable general equilibrium (CGE) models simulate energy systems up to a certain level of technical detail within a particular market structure. Prominent examples of *CGE* models are the MIT-EPPA model used to simulate the world economy and the GEM-E3 model used by the European Commission [40]. Concerning other prominent techno-economic models. One well known model is the MARKAL model, developed by the International Energy Agency [41]. While MARKAL belongs to the group of optimization models, recent modules try to bridge the gap between the techno-economic and macroeconomic models [42], one of them being TIMES (The Integrated MARKAL-EFOM System). TIMES combines a technical engineering with an economic approach, thus merging the characteristics of both [43]. Further, recent techno-economic models try to incorporate aspects of system dynamics into energy system models, for example, POLES [35,44]. System Dynamics models are used to analyze the behaviour of different actors and, thus, are able to provide new insights to energy system modelling.

GENeSYS-MOD is based on the Open-Source Energy Modelling System (OSeMOSYS) framework, developed by the Royal Institute of Technology in Stockholm, Sweden [45]. OSeMOSYS was used by Moura et al. [46] in a game-theoretical framework to understand the bargaining power of South American countries concerning energy policies, by Rogan et al. [47] to analyze the impact of different energy efficiency measures in the Irish energy market and by Lyseng et al. [48] to model the Alberta, Canada, energy system and to study the ability of the region to comply with the 2 degrees commitment of the COP 21. Löffler et al. [14] extended OSeMOSYS to GENeSYS-MOD by including new functionalities, such as a modal split for transportation, an improved trade system and an enhanced focus on environmental budgets. Lawrenz et al. [49] further enhanced GENeSYS-MOD in their case study on transition pathways of the Indian energy system, while Burandt et al. [34] introduced the second model version, with improvements to storages, time slices and performance optimization (for a detailed description of GENeSYS-MOD and its blocks of functionality, see Appendix C).

Specifically, GENeSYS-MOD is different from CGE models because of its capacity to split the energy market into different sectors, technologies and processes; from traditional electricity market models because of its capacity to endogenously optimize the power, transportation and heating sectors, while accounting for sector coupling (Sector coupling refers to the interdependency and substitutability of energy carriers across sectors, for example, electric vehicles and electrolysis.); and from macroeconomic models because of its high level of technical detail. Overall, GENeSYS-MOD is similar to the TIMES model regarding its modular structure and general modelling paradigm. The key advantage of GENeSYS-MOD is the open-source approach of code and data and that the model is freely available. The capacity of GENeSYS-MOD to subdivide the energy system into sectors, technologies and regions; its ability to account for sector coupling; and its high degree of technological features are necessary characteristics of a model attempting to understand the consequences of exogenous variations in energy and climate policies on each supply option, energy sector and modeled region. Overall, numerical models allow analyzing a great variety of problems across several sectors and sciences. Techno-economic models have shown the ability to analyze costs and effects of a transition toward low-carbon technologies in national energy and power mixes. The power sector is the one sector that historically and recently, has received the most attention. With European [50,51], American [52] and global models [14,53] analyzing different transition pathways and their effect on the aggregated cost of the system. Additionally, the scope of these models have expanded to other regions, like China [54] and India [49,55], as well as to other sectors of the energy system in multi-sectoral models [33]. The latter is of high importance, as most previous studies only target the power sector, omitting significant effects due to sector-coupling. Still, a detailed analysis of the Mexican energy system using an integrated, multi-sectoral, approach is missing.

GENeSYS-MOD optimizes the energy system by using a system of linear equations as constraints and inputs to minimize the aggregated cost of the energy system, while securing the supply of energy in a specific region. Equations (1) and (2) show the objective function, as well as the decomposition of technology costs in the model. Equation (1) minimizes the total discounted costs of the energy system (z). Furthermore, Equation (2) defines the costs of each technology as the discounted sum of operating costs, capital investment, emission penalties and salvage values. These equations serve as the core of the model, with additional constraints (see Appendix C) determining the proper functionality of elements, such as energy balances, emission limits or renewable integration.

$$\begin{aligned}\text{Min } z = \sum_{y,r} \Bigg(\sum_{t} \left(TotalDiscountedCostByTechnology_{(y,t,r)} \right) + \sum_{s} \left(TotalDiscountedStorageCost_{(y,s,r)} \right) \\ + DiscountedAnnualTotalTradeCosts_{(y,r)} + \sum_{f,rr} \left(DiscountedNewTradeCapacityCosts_{(y,f,r,rr)} \right) \Bigg)\end{aligned} \tag{1}$$

$$\begin{aligned}&TotalDiscountedCostByTechnology_{(y,t,r)} = \\ &\qquad DiscountedOperatingCost_{(y,t,r)} + DiscountedCapitalInvestment_{(y,t,r)} \\ &\quad + DiscountedTechnologyEmissionsPenalty_{(y,t,r)} - DiscountedSalvageValue_{(y,t,r)} \quad \forall y,t,r\end{aligned} \tag{2}$$

Figure 5 portrays a stylized version of the general structure of the model. From left to right, we have power generation technologies. These technologies provide electricity to the grid and extract resources from raw energy carriers that also provide energy for industrial and residential heating. The electricity provided to the power grid can be used to satisfy power demand in the region, regional power trade, electric engines, batteries and generation of gas or heat through power-to-heat and power-to-gas technologies. Other critical energy carriers are waste and biomass, which can be used for biofuels or direct use for heat. Finally, the transportation sector is divided into passenger and freight transport with respective technology options. The model then uses the range of technology options to fulfil the (exogenously) defined demands for electricity, heat and transportation, while staying true to constraints, such as renewable targets or emission reduction goals. To achieve this, the model optimizes the construction of new capacities of generation facilities, sector-coupling options, and energy storage. (Since the model can choose freely how to fulfil the final demands, it can use technologies that link the different sectors, usually by electrification. This means that heat or transportation can be provided by electric options, thus coupling the traditionally segregated sectors). As a result, the cost-optimal pathway toward the achievement of these long-term scenarios is obtained for all sectors. For more information on the technical side of the model, please refer to Appendix C, Löffler et al. [14], Howells et al. [45] and Burandt et al. [34].

As a techno-economic numerical model, GENeSYS-MOD is subject to the relevant limitations of these kind of models. It requires exogenous inputs on forecasted demands, costs and technological paths. Regarding the demand for transportation, power and heating, these come from third-party sources, such as the national program for the development of the energy system (PRODESEN) or are imputed with the use of GDP and population estimates. Furthermore, because of the integrated modelling approach for the entire period between 2015 and 2050, it is only possible to include a given number of time slices per year, sixteen-time slices, including four different seasons (spring, summer, autumn, winter) and four intraday cuts (morning, peak, evening, night). These time slices intend to account for peak demand periods in summer and afternoons. Welsch et al. [56] compare an enhanced OSeMOSYS implementation with 16 time slices to a full hourly dispatch model and find the differences to be relatively small (roughly 5% deviation). However, it is true that more granular time windows would be optimal, given the difficulties to push the system toward a full decarbonization path. Linking the more broadly-based energy system development done in this paper to more detailed electricity sector models might be a good point for further research. Further, assessing the cost-optimal transition on a smaller regional level (e.g., municipalities) can lead to additional insight into the development of the Mexican energy system. This also holds true for the assessment of optimal renewable shares, where a regional approach (instead of a sectoral approach) might provide further insights, especially since policies are often determined at a regional level (e.g., using decision making processes, instead of pure optimization) [57–59]. Finally, capital, variable and O&M costs come from exogenous sources and, therefore, influence the model results.

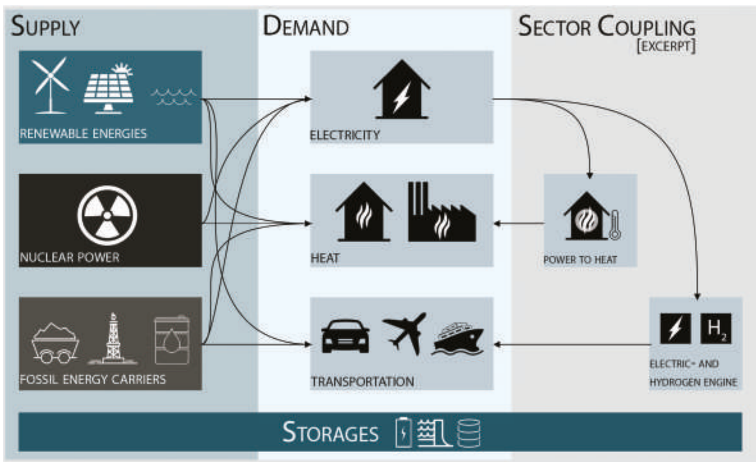

Figure 5. Stylized graph of the stucture of the Global Energy System Model (GENeSYS-MOD).

For this exercise, the model looks at the Mexican energy system by dividing it into three sectors (power, (low-and high-temperature) heat and (passenger and freight) transportation), 9 regions (BCN, BCS, North, Northeast, Northwest, West, Central, East and Peninsula), a multitude of generation technologies (e.g., utility PV, onshore wind, hydropower, biomass, gas (biogas), geothermal, nuclear, oil, gas (natural gas), hard coal, ...) and 16 time-slices. The modeled period runs from 2015 to 2050, computed in 5-year steps, with 2015 serving as the baseline (calibrated based on the data outlined in Section 2).

4. Results

Before addressing the results of each scenario run, it is essential to point out that there were no noteworthy differences between BAU and National Targets, as shown in Figure 6. The objectives of renewables penetration in the power sector of National Targets are attained even without the intervention of climate policies. This outcome means that current national targets in the power sector are insufficient and do not shape the behaviour of the market. Because the results from both scenarios are so similar, the remaining section presents them as a unified scenario: BAU/National Targets. To verify the proper workings of the model, a model validation has been conducted and can be found in Appendix D.

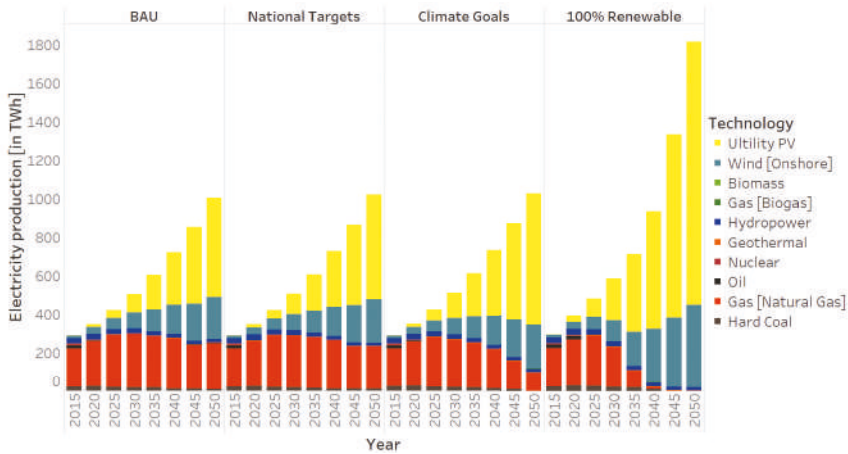

Figure 6. Electricity generation per year for all four scenarios.

4.1. Electricity Sector

The electricity sector sees a significant increase in generation from of renewable technologies. This general trend is independent of the scenario (see Figures 6 and 7). However, the Climate Goals and 100 percent Renewables scenarios result in overall higher renewable shares. Solar power reveals itself as the dominant technology in all scenarios. Even in the BAU/National Targets scenario, it reaches 52.3% of electricity generation, while for 100 percent Renewables, it provides as much as 75.4% by 2050. Electricity generation due to sector-coupling drastically reacts to more ambitious climate targets, with the 100 percent Renewables scenario clearly surpassing BAU/National Targets, as well as Climate Goals (see Figures 6 and 7). In the BAU/National Targets scenario, generation from natural gas increases in the early years of the modelling horizon, peaking in 2030 and then remaining steady with just a small decline toward the end of the modeled period. For the other two scenarios, it peaks in 2025, after which generation from gas-fueled technologies immediately starts to decline. In 100 percent Renewables, the production from natural gas facilities almost disappears by 2040.

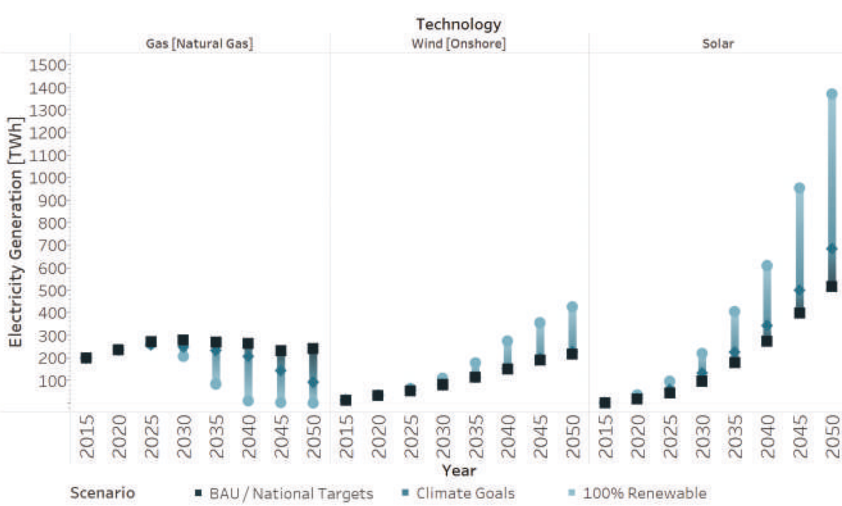

Figure 7. Electricity generation from nat. gas, solar photovoltaic (PV) and onshore wind energy per scenario.

Each regional power mix heavily depends on its environmental endowments and demand structure. Figure 8 exhibits the regional development of electricity generation for each scenario. While the system is strongly reliant on natural gas across all scenarios for the year 2030, renewable generation also starts ramping up. Solar technologies are ubiquitous to Mexico and appear with varying intensities across all regions. Hydroelectric power generation remains relatively constant (in absolute terms), although its share diminishes due to the general increase in electricity generation. By 2050, all scenarios show large amounts of solar PV, especially in the Northern regions. Especially in the 100 percent Renewables scenario, the North region supplies large amounts of solar-based electricity to the surrounding regions. Finally, biofuels only appear competitive in the electricity sector for the Central region in the scenarios Climate Goals and, to a lesser extent, in 100 percent Renewables. This is due to the region's small size and comparatively small endowments of RES potentials, yet high energy demands.

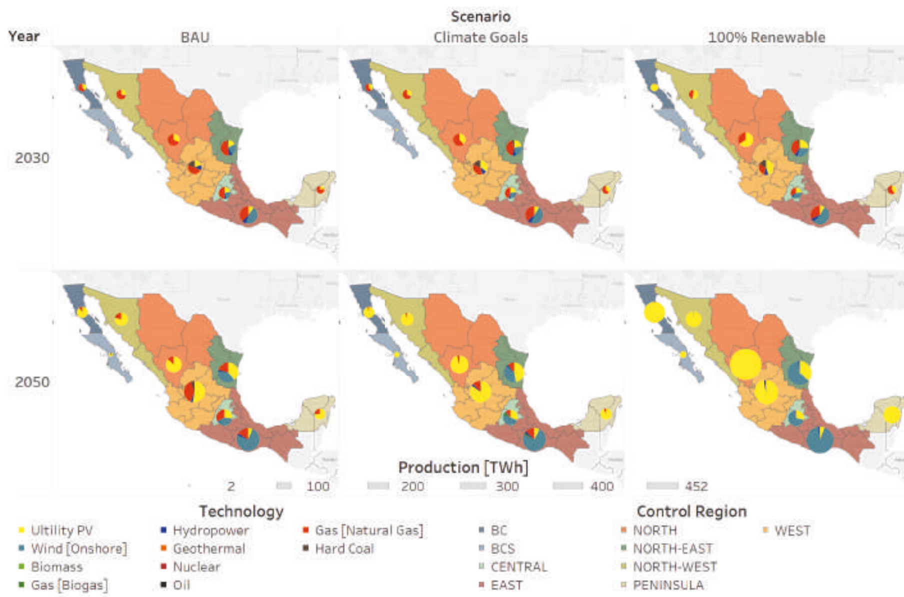

Figure 8. Regional generation of electricity in the years 2030 and 2050 per scenario.

Table 2 presents the installed capacity for natural gas, onshore wind, solar PV and storage technologies across years and scenarios. Intense solar radiation across the nation drives the steady increase in solar PV deployment, with 2050 values ranging from 320.73 GW (BAU/National Targets) to 842.89 GW (100 percent Renewables). Wind also experiences a steady expansion of generation capacities (especially in the East region) but to a much smaller degree than solar. Onshore wind capacities increase from 3.4 GW in 2015 to 56.9 GW in BAU/National Targets, 67.8 GW in Climate Goals and 121.5 GW in 100 percent Renewables by 2050. Strong sector-coupling effects between the electricity and other sectors (see Section 4.2 for more cross-sectoral information) drive the exponential growth behind wind and solar power in the 100 percent Renewables and Climate Goals scenarios. Furthermore, going hand-in-hand with generation from intermittent renewables, the need for electricity storage also increases. While BAU/National Targets utilizes about 110.1 GW of electric storage options, (electricity storage in GENeSYS-MOD v2.0 include Lithium-Ion Batteries, Redox-Flow Batteries, Pumped Hydro Storages and Compressed Air Electric Storages) the 100 percent Renewables scenario requires about 366.7 GW. This difference in storage capacities implies that the storage requirements of 100 percent Renewables are more than three times higher than in BAU/National Targets.

Table 2. Installed capacities for major electricity-generating and storage technologies across scenarios in GW.

		2020	2030	2040	2050
Gas	BAU / National Targets	33.20	36.54	36.22	46.19
	Climate Goals	32.87	32.87	34.02	40.44
	Green Future	32.97	32.84	28.18	26.89
Wind [Onshore]	BAU / National Targets	8.75	21.24	39.26	56.86
	Climate Goals	8.75	21.27	39.34	67.77
	Green Future	8.76	28.26	76.05	121.45
Solar	BAU / National Targets	11.88	56.63	164.81	320.73
	Climate Goals	13.05	78.63	209.22	430.19
	Green Future	21.60	129.81	372.08	842.89
Storages [Electricity]	BAU / National Targets	5.53	18.70	48.18	110.07
	Climate Goals	5.09	25.74	71.42	173.97
	Green Future	6.68	153.99	309.85	366.74

4.2. Energy System Development

Looking at the entire energy system, RES play a vastly different role for each scenario (see Figure 9). While the most ambitious 100 percent Renewables scenario sets the target of 100% renewables use in 2050 (and thus is required to achieve it), the more conservative BAU/National Targets does not enforce climate targets and, thus, remains significantly fueled by conventional energy sources, namely natural gas and oil, even as late as 2050. The Climate Goals scenario takes the middle ground, with about 50% RES-based energy generation by 2050. The total final energy generation only shifts marginally between the scenarios but with Climate Goals and 100 percent Renewables consistently lower than BAU/National Targets. This is due to efficiency gains made possible by sector-coupling, with electrification options being used far more extensively.

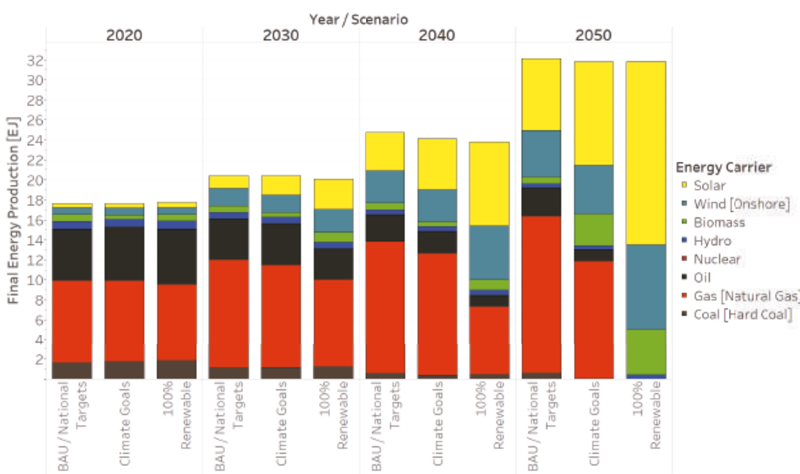

Figure 9. Final energy mix across all sectors per scenario in Exajoule (EJ).

4.2.1. Sectoral Analysis

Figure 10 plots the sectoral share of RES across scenarios. The figure also portrays (sector-coupling) electricity usage in the sectors mobility (aggregating passenger and freight transport) and industrial heating.

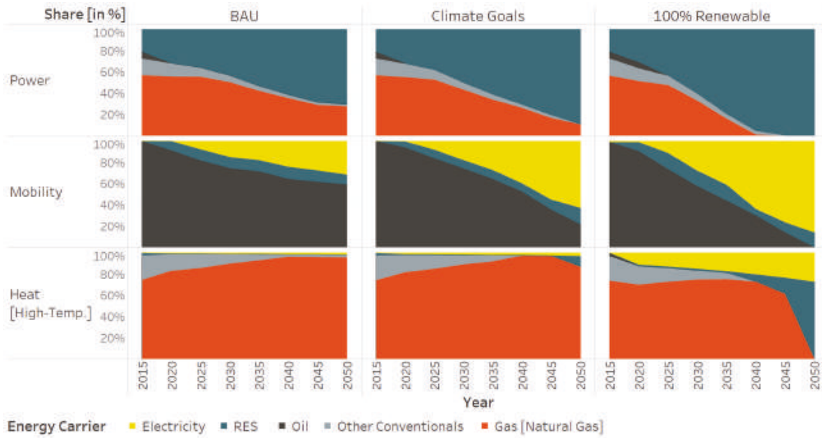

Figure 10. Share of Renewable Energy Sources per sector and scenario.

For the power sector, the entrance of solar and wind technologies to the power matrix replaces natural gas across scenarios. The only difference between them is the steepness of the decarbonization path. The electricity sector of 100 percent Renewables is fully decarbonized by 2045, while Climate Goals still has a marginal share of natural gas facilities in 2050 and under the BAU/National Targets, natural gas production remains at almost 30%. After the power sector, the transportation sector is the next to decarbonize. The sector remains oil-powered in the BAU/National Targets scenario, although a significant share of electricity and RES appears after 2025. For Climate Goals, the transportation sector is about 80% decarbonized by 2050, mostly with the use of electric vehicles and biofuels. 100 percent Renewables achieves 100% renewables in the transportation sector with a higher share of electric-powered vehicles. On the other hand, a particular issue in the path toward full decarbonization is high-temperature heating. In high-temperature heating, both BAU/National Targets and Climate Goals show almost no decarbonization, only 100 percent Renewables enforces a renewable target that obliges the total decarbonization of industrial heating. When the model decarbonizes industrial heating, it opts for a mixture of electricity, hydrogen and biomass (mostly in the form of biogas). The reason behind difficulties in the decarbonization of industrial heating is the sharp cost difference between low-carbon and (regular) carbon-intensive processes in the sector.

In general, a strong trend of sector-coupling can be seen when climate goals are prioritized. This holds mostly true for the mobility sector, where even the BAU/National Targets scenario achieves about 30% electricity share, reaching almost 90% in the 100 percent Renewables scenario. This behaviour also explains the heavy increase in electricity generation across scenarios, as observed in Section 4.1.

4.2.2. Costs

In this section, we analyze the effect of the iterative routine. This routine consists of optimizing the power, transportation and industrial heating sectors under 20 different and binding shares of renewables. The binding shares start at 0% and grow in 5% intervals until reaching full decarbonization. Figure 11 presents the sectoral percentage change in total-discounted-system-costs between a fully decarbonized system and a partially decarbonized one. This graph does not portray any specific scenario assumption but instead takes the technology learning curves and forces the model to use a fixed percentage of renewables in each respective sector(s). Electricity used in the heat or transportation sectors is being distributed to renewable/non-renewable energy via the annual share of RES in the power mix (e.g., RES produced 70% of electricity in 2035, then 70% of electricity in transport would count as renewable and 30% as non-renewable). In the figure, values above zero represent higher total costs than the 100 percent Renewables scenario, while values below zero mean that this level of RES integration would be more cost-competitive than 100 percent Renewables. Naturally, the minimum of the curves represents the cost-optimum share in each of the sectors. To the best of our knowledge, this is the first time a techno-economic optimization model looks at cost variations of the entire energy system across different shares of renewables while accounting for sector coupling.

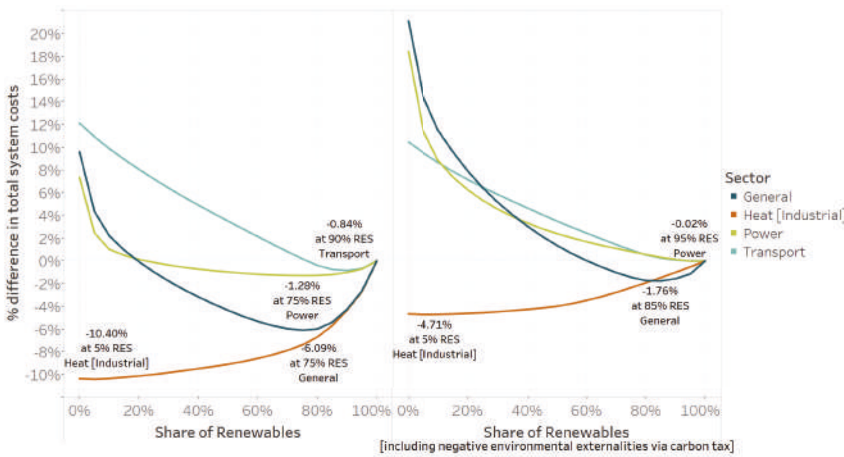

Figure 11. Relative cost difference of different levels of renewable integration (Baseline: 100% RES).

For the power sector and the energy system as a whole, the model portrays two U-shape convex curves. Industrial heating resembles a curve of positive slope, with the percentage increase in total system costs steadily increasing with the share of renewables. On the other hand, the transportation sector display the opposite behaviour, with a negative slope indicating that sector costs decrease with renewable integration. Two insights come from this figure. First, the energy-system cost-curve reaches its cost-optimal share at 75%. High-temperature heat reaches it at 5%, power at 75% and transportation at 90%. Another result is the low-cost difference between the cost-optimal point of 75% RES in the electricity sector and its marginal cost of increasing its share of renewables. Between 75% and 100%, the cost difference is merely 1.28%. For the entire energy system, this difference increases to 6.09% of total system costs due to the high costs of decarbonizing industrial heating. It is worth mentioning that uncertain technology learning curves, fossil fuel prices or energy demands drive these results. However, these results provide an estimate of the cost difference between different penetration scenarios of renewable sources in the energy sector.

A sensitivity exercise, introducing an exogenous CO_2 price, representing an internalization of adverse external effects of carbon dioxide emissions [60], is shown on the right-hand side of Figure 11. The introduction of such an environmental carbon tax (of 180€/tCO_2 in 2015) shifts results quite significantly, although the overall picture remains the same. Industrial heat still sees a low share of RES in its cost-optimal version, while the electricity sector moves up to 95%, pushing the cost-optimal share of RES in the energy system to 85%. In addition, the steepness of the curves is shifted, with a vastly higher increase in total system costs for low amounts of renewables. This exercise demonstrates that a CO_2 tax that internalizes these negative environmental effects can have a significant effect on the outcome of such cost-driven studies and move the cost-optimality even further in favour of RES.

4.2.3. Emissions

Figure 12 plots the relative annual emissions for each of the three scenarios compared to 2015. While the Climate Goals scenario reduces its emissions by 36%, the BAU/National Targets scenarios remain rather constant in their emissions and result in a net increase of about 4% in 2050. What is important to keep in mind, however, is that this 4% increase in emissions in BAU/National Targets goes against a major increase in energy demand across all sectors that comes along with the expected growth of population and wealth. Finally, 100 percent Renewables reaches its target of 100% decarbonization in 2050.

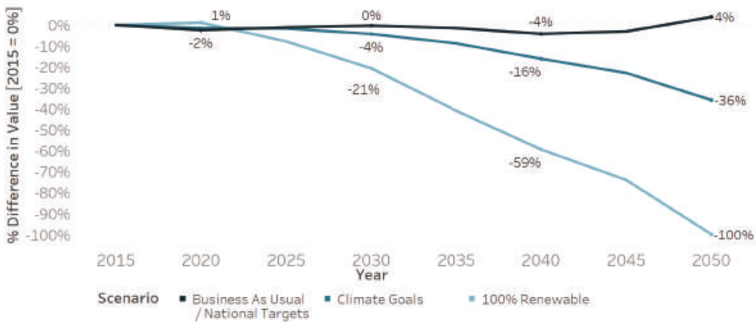

Figure 12. Annual CO_2 emissions per scenario (relative to 2015).

Summing up the yearly emissions, 100 percent Renewables, with its 100% renewable target in 2050, reaches total emissions of about 7.16 Gt CO_2, while Climate Goals emits about 9.63 Gt CO_2 and BAU/National Targets just above 12.0 Gt CO_2, thus more than 60% more than the 100 percent Renewables scenario.

5. Conclusions

In this article, we use the Global Energy System Model (GENeSYS-MOD) to optimize pathways for the Mexican energy system under different energy and climate policies. GENeSYS-MOD is a techno-economic cost-minimizing energy model that differentiates from traditional bottom-up models by the integration of traditionally segregated energy sectors (power, transport and heat). The goal of the study is to analyze the consequences of current renewable targets and climate goals in the future cost composition and structure of the energy sector, to do this we use four different scenarios: BAU, National Targets, Climate Goals and 100 percent Renewables. BAU optimizes the energy system without any constraints regarding renewable targets or climate goals. National Targets forces the model to attain current renewable targets. Climate Goals does the analogous with Mexico's climate goals, and, finally, 100 percent Renewables forces the optimization routine to decarbonize the energy system by 2050. Additionally, we also run an iterative optimization routine by increasing the share of renewables in each sector between 0% and 100% in 5% steps. In each iteration, the model attains, without exceeding, the imposed share of renewable sources. Our modelling approach allows us to investigate the cost consequences and changes in energy mix of national renewable targets and climate goals between the scenarios. Moreover, comparing BAU with Climate Goals and National Targets permits us to infer the suitability of these policies by understanding how much they deviate from the two extreme scenarios (BAU and 100 percent Renewables). Finally, the optimization routine allows us to determine the cost-optimal share of renewables in the energy system and the marginal cost of deviating from this optimal share. To the best of our knowledge, this paper is the first optimization approach analyzing how the total discounted costs of the energy system vary under different sectoral renewable targets. Additional contributions relate to the analysis of the Mexican energy sector while accounting for sector coupling and the insights gained from the comparison of various scenarios.

Results from the study show that Mexican renewable targets are insufficient and sub-optimal: the model shows that the optimal share of renewables for the generation of electricity is 80%, that is, 30% higher than current commitments in the national strategy for the promotion of clean fuels and technologies [15]. Even more, the share of renewables in the power mix between BAU and National Targets is very similar. This indicates that current renewable targets do not even deviate from a scenario without climate policies, meaning that there is a misalignment between climate goals and renewable targets. In principle, both policies should aim for the same goal. For example, if the power sector renewable target of 50% is significantly lower than the penetration of renewables under the fulfillment of climate goals, it is redundant and inefficient to implement both policies. At the minimum, renewable targets should mimic the sectoral decarbonization paths of climate goals. Regarding the energy mix, natural gas and photovoltaics shape the future of the Mexican energy system, across all regions, except for the wind-rich East region, strongly relying on onshore wind turbnies for the generation of electric power. In the intermediate term, however, an ongoing dependence on natural gas can be observed across all scenarios. When aiming for full decarbonization (100 percent Renewables), the energy mix relies on solar, wind and biomass to satisfy the energy needs of the country, using the grid, as well as energy storages, as load balancing options.

Concerning sectoral decarbonization paths, it is evident that the power, transport and heating sectors present different patterns. For electric power, the cost competitiveness of photovoltaics and wind turbines push the sector toward decarbonization across all scenarios and regions. Moreover, due to sector coupling, the introduction of these cost-competitive technologies in the power mix is a crucial factor for the decarbonization of the transportation sector. The higher the share of renewables in the power sector, the greater the introduction of electric vehicles in the transportation sector. The heating sector is the last sector to decarbonize because of substantial cost differences between conventional and renewable heat.

Furthermore, the computation of sectoral cost minima exhibits interesting results. As previously noted, the cost-optimal share of renewable targets in the power sector is 75%, 25% points higher than current renewable targets. For the transportation sector, the share is as high as 90%, suggesting significant economic advantages of increasing the share of electric vehicles in this sector. For the heat sector, its share reflects the high cost of renewable heat and present an optimal renewable target of only 5%. Finally, for the energy system as a whole, the 2050 optimal renewable share is 75%. As an additional exercise, we analyze how costly it is to increase the share of renewables in both the power and energy sectors. Increasing the power sector to full decarbonization only increases total costs by 1.28%; for the whole energy system, total costs would increase by 6.09% (mostly driven by industrial heating). Finally, the difference in total cumulative emissions between BAU/National Targets and 100% Renewable is 4.85 gigatonnes of CO_2 (more than 10 times the current yearly emissions of Mexico [61–63]).

The results of this study air several exciting conclusions: public policies for the introduction of renewables in the power sector need to change. They are equivalent to a scenario without climate policies, disconnected from the climate goals of the country and significantly lower than the estimated cost-optimal share of renewables in the power sector. Furthermore, aiming for more stringent shares of renewables in the power sector or stricter climate goals for the mitigation of greenhouse gases only marginally increases the total cost of the energy and power systems. Other relevant insights are the reliance of the power system on photovoltaic and natural gas, the high cost-optimal share of renewables in the transportation sector and its low counterpart in industrial heating. Moreover, this article can help policymakers in the design and implementation of specific targets and policies for the decarbonization of the heating and transportation sectors by providing the cost-optimal share of renewables in each sub-sector.

Author Contributions: Conceptualization, L.S., T.B., K.L. and P.-Y.O.; methodology, L.S., T.B. and K.L.; software, T.B. and K.L.; validation, L.S., T.B. and K.L; formal analysis, L.S. and P.-Y.O.; data curation, L.S., T.B. and K.L.; writing—original draft preparation, L.S., T.B., K.L. and P.-Y.O.; writing—review and editing, P.-Y.O. and K.L.; visualization, L.S. and K.L.; supervision, P.-Y.O.

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Conflicts of Interest: The authors declare no conflict of interest.

Appendix A. Regional Disaggregation

East, located in the eastern-southernmost part of the country has the largest installed capacity and penetration of renewables across regions. Wind-parks and hydroelectric-dams cover up to 50% of the region's installed capacity. West, located in the center west of the country is the second largest region regarding installed capacity. Its energy mix has combined-cycle, hydroelectric, carboelectric and oil-indexed facilities as driving technologies. Northeast is located in the north-east of the country, next to the Gulf of Mexico and south of Texas. An extensive network of gas pipes connects it with the shale reserves of the United States making its power mix heavily dependant on natural gas. This region is also experiencing a surge of wind parks in the north part of the Gulf of Mexico. Northwest and North are industrial and scarcely populated regions that use combined natural gas, oil and dams to satisfy their energy demands. Central includes Mexico City and its metropolitan area plus additional center states. The region is poor in natural endowments and it is a net importer of electric power. Its power matrix consists of natural gas and oil. BC locates south of California, in the northwest of Mexico. It has natural gas and geothermal energy as the main sources of power. Finally, Peninsula, located in the Yucatan peninsula and BCS in the southern part of the California peninsula depend on natural gas and oil plants.

Table A1. States and their corresponding Regions.

Baja California (BC)	
Baja California	
Southern Baja California (BCS)	
Baja California Sur	
Central	
Hidalgo	Mexico City
Mexico	Morelos
East	
Chiapas	Guerrero
Oaxaca	Puebla
Tabasco	Tlaxcala
Veracruz	
North	
Chihuahua	Durango
North-East	
Coahuila	Nuevo Leon
Tamaulipas	
North-West	
Sonora	Sinaloa
Peninsula	
Campeche	Quintana Roo
Yucatan	

Table A1. *Cont.*

West	
Aguascalientes	Colima
Guanajuato	Jalisco
Michoacan	Nayarit
Queretaro	San Luis Potosi
Zacatecas	

Appendix B. Input Data

Appendix B.1. Technology Costs

Table A2. Capital Costs of main electricity generating technologies in M€/GW. Data based on Carlsson et al. [30], Basis [31], Gerbaulet and Lorenz [32], Ram et al. [33] and Burandt et al. [34].

	2015	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Utility PV	1000	580	466	390	337	300	270	246
Onshore Wind	1250	1150	1060	1000	965	940	915	900
Offshore Wind	3500	2637	2200	1936	1800	1710	1642	1592
Geothermal	3988	3775	3584	3392	3221	3049	2895	2740
Coal-Fired Thermal Plant	1600	1600	1600	1600	1600	1600	1600	1600
Gas-Fired Thermal Plant	650	636	621	607	593	579	564	550
Oil-Fired Thermal Plant	650	627	604	581	559	536	513	490
Coal-Fired CHP	2030	2030	2030	2030	2030	2030	2030	2030
Gas-Fired CHP	977	955	934	912	891	869	848	826
Oil-Fired CHP	819	790	761	733	704	675	646	617

Appendix B.2. Fuel Costs

Table A3. Fossil Fuel Cost in M€/PJ, based on SENER [21], International Energy Agency [29].

	2015	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Oil [Import]	7.12	10.18	11.02	11.86	11.37	10.88	10.39	9.91
Coal [Import]	1.52	1.54	1.53	1.52	1.44	1.36	1.28	1.20
Nat. Gas [Import]	6.63	6.54	7.72	8.91	9.15	9.38	9.62	9.86
Oil [Domestic]	6.76	9.68	10.47	11.27	10.80	10.34	9.87	9.41
Coal [Domestic]	1.44	1.47	1.45	1.44	1.36	1.29	1.21	1.14
Nat. Gas [Domestic]	6.30	6.21	7.34	8.46	8.69	8.91	9.14	9.36

Appendix B.3. Renewable Potentials

Table A4. Renewable Potentials in Gigawatts (GW) installed capacity per region. Data (wind and hydro) based on SENER [19]. The data used for the computation of solar capacity potentials can be found in Table A5.

	Utility PV	**Onshore Wind**	**Hydro**
BC	147.0	159.0	0.6
BCS	152.8	67.5	0.6
CENTRAL	25.4	33.0	0.4
EAST	369.9	188.9	8.3
NORTH-EAST	318.9	339.5	2.3
NORTH-WEST	841.7	85.7	1.0
NORTH	1815.1	418.6	1.2
PENINSULA	113.7	175.9	0.0
WEST	429.4	110.1	4.1

Table A5. Data and assumptions used for the computation of solar PV potentials.

Control Region	Irradiation [kWh/m^2/d]	Surface Area [km^2]	Total Population	Population per km^2	Available Area [%]	Conversion Efficiency	Resulting Potential in GW
BC	7155.1	71,450	3,155,070	44.2	0.03	0.23	147.0
BCS	7190.0	73,909	637,026	8.6	0.03	0.23	152.8
CENTRAL	5354.0	49,538	28,469,187	574.7	0.01	0.23	25.4
EAST	5279.4	365,524	27,943,184	76.4	0.02	0.23	369.9
NORTH-EAST	5761.1	144,405	7,406,680	51.3	0.04	0.23	318.9
NORTH-WEST	7394.6	237,555	5,629,180	23.7	0.05	0.23	841.7
NORTH	7251.7	522,372	7,787,790	15.0	0.05	0.23	1815.1
PENINSULA	5578.8	141,736	4,103,596	29.0	0.015	0.23	113.7
WEST	6310.8	355,014	26,012,744	73.3	0.02	0.23	429.4

Appendix C. Model Structure

The GENeSYS-MOD framework consists of multiple blocks of functionality, that ultimately originate from the OSeMOSYS framework. GENeSYS-MOD is a cost-optimizing linear program, focusing on long-term pathways for the different sectors of the energy system, specifically targeting emission constraints, the integration of renewables and sector-coupling. The model minizes the objective function, which comprises total system costs (encompassing all costs occurring over the modeled time period).

(Final) Energy demands are given exogenously for each modeled time slice, with the model computing the optimal flows of energy and the resulting needs for capacity additions and storages. Additional demands through sector-coupling are derived endogenously. Constraints, including energy balances (ensuring all demand is met), maximum capacity additions (e.g., to limit the usable potential of renewables), RES feed-in (e.g., to ensure grid stability) and emission budgets (given either yearly or as a total budget over the modeled horizon) are given to ensure proper functionality of the model and yield realistic results.

All fiscal units are discounted towards the base year of 2015, using a discount rate of 5%. Also, the model assumes a sinking fund depreciation, with assets that are within their operating lifetime at the end of the modelling period (here: 2050) being given a *salvage value* that is added back to the objective function. This ensures that investment in the later periods of the model does not come to a halt.

In its basic configuration, GENeSYS-MOD operates from the perspective of an omniscient social planner, including perfect foresight and perfect competition within markets. Figure A1 present the underlying block structure of GENeSYS-MOD v2.0, with the additions made in this study (namely a more detailed regional data set and a new block that adds the option for finding the cost-optimal level of RES in the energy system).

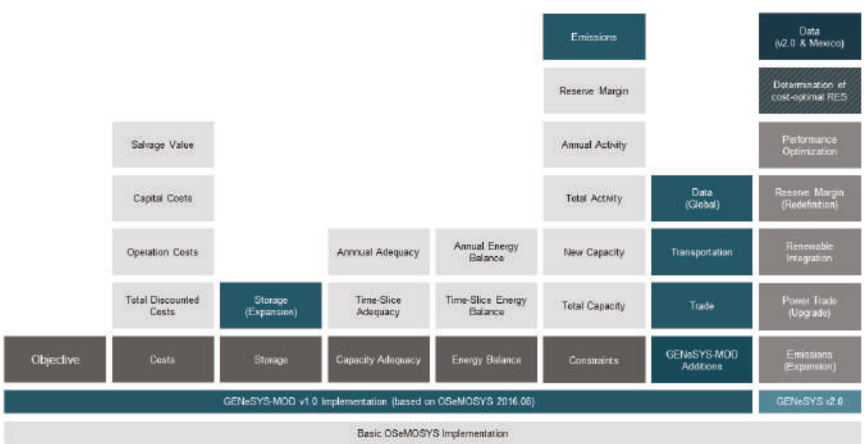

Figure A1. Model structure of the GENeSYS-MOD implementation used in this study.

This determination of the cost-optimal level of RES, as well as the resulting changes in total system costs are obtained via an iterative loop of model runs, each with a predefined and fixed level of RES penetration for the chosen sectors (ranging from 0% to 100% RES). This yields a cost level for each iteration of the process, thus yielding both the lowest (and thus cost-optimal) point, as well as the relative increase that occurs when deviating from the optimum.

Appendix D. Model Validation

To demonstrate the robustness of the model results, a comparison of computed model results of the (base) year 2015 with actual data from official international reports [61–65] has been conducted. Figure A2 shows the results for emissions, electricity and final energy generation, each with the respective counterpart.

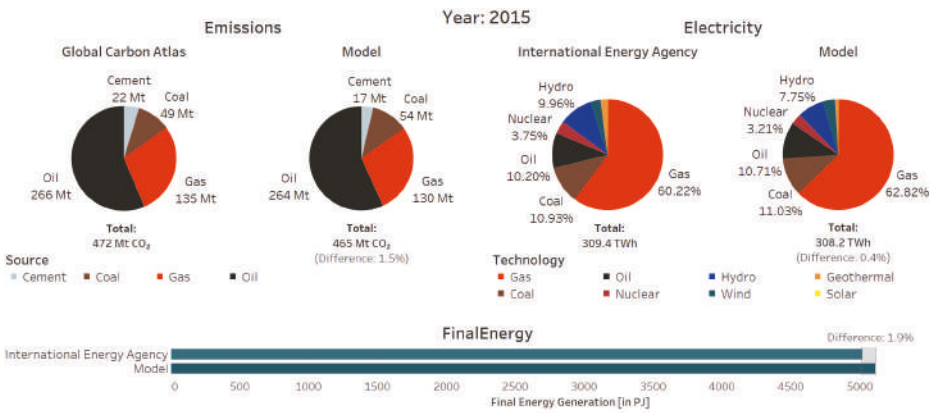

Figure A2. Comparison of model results with actual historical data for the year 2015. Data for emissions from Boden et al. [61], UNFCCC [62] and BP [63]; data for electricity from International Energy Agency [64]; and final energy from International Energy Agency [65].

It can be shown that reasonably close results are obtained within the model computation, with differences between total numbers ranging from 0.4% to close to 2%. As all model data stems from official sources or peer-reviewed academic articles (and is thus assumed to be correct), the model therefore demonstrates that it is working properly.

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Article

Effects of a Delayed Expansion of Interconnector Capacities in a High RES-E European Electricity System

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Abstract: In order to achieve a high renewable share in the electricity system, a significant expansion of cross-border exchange capacities is planned. Historically, the actual expansion of interconnector capacities has significantly lagged behind the planned expansion. This study examines the impact that such continued delays would have when compared to a strong interconnector expansion in an ambitious energy transition scenario. For this purpose, scenarios for the years 2030, 2040, and 2050 are examined using the electricity market model PowerFlex EU. The analysis reveals that both CO_2 emissions and variable costs of electricity generation increase if interconnector expansion is delayed. This effect is most significant in the scenario year 2050, where lower connectivity leads roughly to a doubling of both CO_2 emissions and variable costs of electricity generation. This increase results from a lower level of European electricity trading, a curtailment of electricity from a renewable energy source (RES-E), and a corresponding higher level of conventional electricity generation. Most notably, in Southern and Central Europe, less interconnection leads to higher use of natural gas power plants since less renewable electricity from Northern Europe can be integrated into the European grid.

Keywords: European electricity system; interconnector capacities; delayed grid expansion; electricity market modeling; decarbonization; renewable integration

1. Introduction

With the signing of the United Nations Paris Agreement on 12 December 2015, 195 states or associations of states [1] committed themselves to limiting global warming to well below 2° C when compared to the pre-industrial level [2]. To implement this goal, the European Commission (EC) presented its 2050 long-term strategy on 28 November 2018 [3]. In this document, the goal of a climate-neutral European economy for the year 2050 is outlined. In order to achieve this goal, a significant expansion of renewable energies especially in the electricity sector must be achieved [4]. For the electricity sector, most scenarios assume that a focus will be on the expansion of technologies providing electricity from renewable energy sources (RES-E) such as solar and wind [5–7]. Several studies have shown that an improved spatial distribution of RES-E capacities within Europe is helpful to balance the fluctuations of wind flow and solar radiation [8–10].

In 2017, the European Commission agreed to implement the European Energy Union [11]. This strategy consists of five dimensions: energy security, a fully-integrated internal energy market, energy efficiency, decarbonization, and research. An important component for achieving the Energy Union is the expansion of European electricity transmission capacities [12]. In Reference [13], the European Commission already reported in detail on the state of the internal energy market and pointed out that sufficient cross-border transmission capacities are a necessary requirement for achieving the energy policy goals. The advantages resulting from the expansion of the European transmission grid are also described in a large number of studies. Expansion of the transmission grid is being described as a "no regret" strategy [14], an efficient flexibility option [15], a requirement for a cost-efficient RES-E extension and integration [16,17], and as “needed to achieve the European targets cost-efficiently” [18].

However, the EU Commission has also pointed out the stalling of the expansion of interconnector capacities. This hampers the continued development of the internal energy market. On behalf of the EU Commission, Roland Berger Strategy Consultants [19] identified the regulatory framework as a major obstacle to the expansion of cross-border transmission capacity. In addition to regulatory issues, Battaglini et al. [20] also indicate a lack of public acceptance as a cause for the delay in grid expansion. In 2014, the EU Commission launched a package of measures called "Connecting Europe Facility" to improve investment conditions. These measures notably aim at improving and harmonizing approval procedures and adapting regulatory regimes with particular emphasis on dealing with risks in network expansion. The Agency for the Cooperation of Energy Regulators (ACER) has identified significant delays in the projects of common interest (PCI). ACER [21] has shown that 75% of PCIs in the phase of “permitting” are delayed or have been rescheduled.

Many studies compare different levels of grid expansion while maintaining CO_2 reduction [8,14] or RES-E targets [17,22,23], to determine the cost-optimal mix through a variation in the expansion of RES-E technologies, back-up capacities, or storage units. As part of the Ten-Year Network Development Plan (TYNDP) 2018, a "no grid" scenario was conducted for the year 2040, in which no further grid expansion is assumed after 2020. All other input data, such as power plant fleet or electricity demand, were kept corresponding to the reference scenario. The authors conclude that “No Grid is incompatible with the achievements of European emission targets” [24]. An additional 156 TWh of RES-E is curtailed per year on average across the scenarios considered and “the grid built between 2020 and 2040 allows a further 10% decrease in power sector CO_2 emissions as compared to the 1990 levels” [24].

The present paper focuses on the delay of interconnector expansion and analyzes what impact a persistence of current delays in the expansion of interconnector capacities would have in a high RES-E scenario. The focus is on quantifying the effects of delay of interconnector expansion on the indicators’ CO_2 emissions, generation mix, electricity exchange, and variable costs of electricity generation. Scenario years 2030, 2040, and 2050 are being considered with RES-E shares in electricity demand of 62% to 99%. Results show that both CO_2 emissions and variable costs of electricity generation increase in case of delayed interconnector expansion. This effect is most significant in scenario year 2050, where lower connectivity roughly leads to a doubling of both CO_2 emissions and variable costs of electricity generation. Those effects arise from lower levels of European electricity trading, higher RES curtailment, and corresponding higher conventional electricity generation. With regard to the latter, the analysis indicates a more extensive use of natural gas power plants, especially in Southern and Central Europe, since less renewable electricity from Northern Europe can be integrated.

Section 2 describes methodology and data, including the electricity market model PowerFlex EU, which was used for this analysis. This also includes a review of existing scenarios regarding electricity demand, generation capacities, and net transfer capacities (NTC). The section also explains how the delays in NTC expansion have been derived. The modeling results can be found in Section 3. In Section 4, the results are being discussed and compared with other studies. Lastly, Section 5 concludes.

2. Methodology and Data

This paper examines in a what-if analysis what impact the persistence of current delays in the expansion of interconnector capacities would have in a high RES-E scenario. Electricity market scenarios from various literature sources were evaluated to determine future generation capacities and electricity demand. An ambitious energy transition scenario was derived from these data (cf. Section 2.2). To determine the effects of delayed interconnector expansion, the electricity market scenario was modelled with two different interconnector capacity expansion levels. The high connectivity (HiCon) scenario, with strong interconnector expansion, is based on literature values. The lower connectivity (LowCon) scenario was derived by extrapolating the current interconnector expansion delay (cf. Section 2.3).

For this study, scenario years 2030, 2040, and 2050 were considered. The data described was used as input for the electricity market model PowerFlex EU (see Section 2.1). The effect of a delayed expansion was determined with a delta analysis in which the scenarios high connectivity and lower connectivity were compared.

The following indicators were analyzed:

- CO_2 emissions.
- Electricity generation mix.
- Import, export, and transit flows.
- Variable costs of electricity generation.

2.1. General Model Description-PowerFlex EU

PowerFlex EU is a bottom-up partial model of the European power sector that has been applied in a range of consultancy and research projects on a German and European level, such as analysis on flexibility options [25,26] or scenario development [27,28]. It calculates the dispatch of thermal power plants, feed-in from renewable energy sources, and utilization of flexibility and storage options at minimal costs to meet electricity demand and reserve capacity requirements.

The model covers all ENTSO-E member states except Iceland and Cyprus. A transport model approach is used to represent electricity exchange between countries. For each individual country, a homogeneous market area without grid constraints is assumed. Exchange between countries is limited by net transfer capacities (see Section 2.3).

For Germany, thermal power plants with capacities exceeding 100 MW are represented as individual units. For other countries, the thermal power plant fleet is represented as aggregated vintage classes concerning age, fuel type, and technology of the individual plants.

The available electricity produced from run-of-river, offshore wind, onshore wind, and photovoltaic systems is represented by generic feed-in patterns in hourly resolution. The actual quantity of feed-in is determined endogenously, with the result that the available yield of fluctuating electricity can also be curtailed (e.g., in the case of negative residual load and insufficient storage capacity).

The model considers reservoir hydro plants, pumped hydro storage, battery storage, and power-to-gas (PtG) as flexibility options. The flexibility of reservoir hydro plants is modeled with an inflow profile of hydro in hourly resolution, a storage capacity of the reservoir, a given level of the reservoir for the first and the last time step, and an electrical capacity of the turbine. All other flexibility options mentioned are modeled with the following parameter's set: pumping or charging capacity, storage capacity, electrical capacity of the turbine or discharging, and the overall efficiency rate. Power–to-gas is modeled as an electricity to electricity storage option to keep the system boundary closed to the electricity system.

The available battery capacities scale with the installed photovoltaic (PV) capacities, and the available capacities of the electrolysers for Power-to-Gas (PtG) generation scale with variable RES-E capacities installed (for details, see Appendix B).

Heat sector coupling is modelled as a further flexibility option only for Germany and not for other ENTSO-E countries. It is represented by combined heat and power plants (CHP) that can shift their power-to-heat ratio within certain technological limitations. Additional generation and flexibility options in the heat sector include heat storage, electrical heating rods, and gas fired boilers.

Electricity demand is assumed to be inelastic. To derive demand profiles in hourly resolution, a standardized demand profile of the base year 2016 is scaled up using scenario-specific annual demand data (see Section 2.2.1). It is assumed that the load profile shape does not change over time (e.g., by increasing demand of new consumers and sector coupling).

Generation, transmission, and storage capacities are determined exogenously, i.e., the model does not endogenously calculate cost efficient investment or divestment pathways. The model assumes perfect foresight and calculates the cost-minimizing dispatch of given capacities in hourly resolution across a single year (8760 hours). In technical terms, it is formulated as a linear optimization problem, implemented in GAMS, and solved using the CPLEX solver.

2.2. Electricity Market Scenarios

In the following sections, the data used is described. All data used has been published (cf. Appendix A). The input data for Germany is based on the scenario Klimaschutzszenario 95 (KS 95) from Reference [28] and is described in Section 2.2.2. To derive the European input data, a scenario analysis based on a literature review was carried out (cf. Section 2.2.1). In Appendix D, the generation capacities per country, used as model input for the year 2050 are given.

2.2.1. European Scenario

The European scenario was determined by means of a scenario analysis of literature data, including TYNDP 2018 [5], the study eHighway 2050 [29], EU Vision Scenario 2017 [30], and EU Reference Scenario 2016 [31]. In the project Model-Based Scenario Analysis of Developments in the German Electricity System, which takes into account the European context up to 2050 in which this study was carried out. Two European electricity market scenarios were derived: an ambitious scenario in which a strong expansion of RES and a significant decline in conventional power plants are assumed, and an unambitious scenario with much slower progress in European energy transition. The unambitious scenario is based on the EU Reference Scenario 2016 [31]. Non EU28 countries are not covered in the scenario and were taken from TYNDP 2018 scenario Sustainable Transition [5].

The years 2040 and 2050 of the ambitious scenario are based on eHighway 2050 scenario 100% RES [29]. Hydro power and biomass generation capacities increase very strongly in the scenario, which does not seem comprehensible from the perspective of natural restrictions, respectively, and competing land use. Therefore, values of the eHighway 2050 Big & Market scenario [29] were used for these technologies. For hydro power generation capacities, it was further assumed that the installed capacities per country will not fall below the current level. In order to ensure that sufficient secure services are available, the size of natural gas capacities, which decrease significantly in the 100% RES scenario, was also taken from eHighway 2050 scenario Big & Market. The data for the scenario year 2030 was generated on the basis of an interpolation between TYNDP 2018 scenario Best Estimate 2020 [5] and the values of the ambitious scenario for the year 2040. In the following, the ambitious and the unambitious scenario are compared with the spread of the considered scenarios. In Appendix C, the scenarios considered are presented in more detail.

Since the European grid expansion will play an important role especially for a high RES-E scenario with large shares of wind and solar, this paper focuses on the ambitious scenario. Further results from this project, such as the effects obtained in the variation of European scenarios while maintaining the German scenario, will be published as a working paper on www.oeko.de by the end of 2019.

The following scenario presentation focuses on EU28 countries, since some of the scenarios only cover these countries. All ENTSO-E member states, except Iceland and Cyprus, were taken into account in the modeling work.

Electricity Demand

Figure 1 shows the development of electricity demand in the unambitious and the ambitious scenario when compared to the scenario spread that results from the scenarios TYNDP 2018 [5], the study eHighway 2050 [29], EU Vision Scenario 2017 [30], and the EU Reference Scenario 2016 [31]. During the period up to 2050, most of the scenarios show a significant increase in demand, which can be attributed to an overcompensation of efficiency measures by an increase of new electricity consumers, such as electric mobility or heat pumps. The unambitious and ambitious scenarios show a relatively similar trend for electricity demand and are in the midfield of the scenarios considered.

Compared to 2016, the electricity demand increases by 28% in the unambitious scenario and by 31% in the ambitious one.

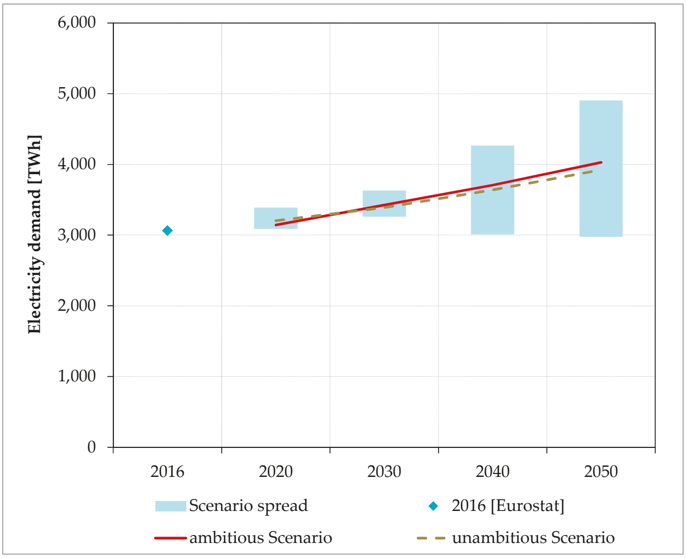

Figure 1. Comparison of annual electricity demand in EU 28 countries based on References [5,29–32].

Renewable Generation Capacities

Figure 2 shows the development of generation capacities for wind, solar, biomass, and hydro power in the unambitious and the ambitious scenario compared to the scenario spread that results from the scenarios TYNDP 2018 [5], the study eHighway 2050 [29], EU Vision Scenario 2017 [30], and EU Reference Scenario 2016 [31].

Wind and solar capacities increase significantly in all scenarios. The ambitious scenario is located at the top and the unambitious scenario is located at the bottom of the scenario funnel. In the ambitious scenario, wind capacities are more than five times higher than in 2016, and solar capacities are more than six times higher. In the unambitious scenario, wind capacities more than double compared to 2016 and solar capacities almost triple compared to 2016. In the unambitious and the ambitious scenario, both biomass capacities roughly double when compared to 2016. Compared to the scenario spread, this is a moderate increase. Hydro power capacities increase compared to 2016 by approximately 50% in the ambitious scenario and by approximately 10% in the unambitious scenario.

Conventional Generation Capacities

Figure 3 shows the development of the conventional generation technologies natural gas, coal, and nuclear power in the unambitious and the ambitious scenario when compared to the scenario spread that results from the scenarios TYNDP 2018 [5], the study eHighway 2050 [29], EU Vision Scenario 2017 [30], and the EU Reference Scenario 2016 [31]. In most scenarios, natural gas capacities show a slight decline over the next few years, which is followed by an increase until 2050 to provide for sufficient secured capacity. In the ambitious scenario, natural gas capacities in 2050 are approximately 15% above today's level. In the unambitious scenario, natural gas capacities increase by approximately 25% compared to today's level.

In all scenarios, coal capacities decline significantly from the current level, even though levels reached in the scenario year 2050 differ significantly. While the ambitious scenario assumes a European-wide phase-out of coal by 2050, the unambitious scenario assumes that coal capacities will decline to approximately 35% by 2040 compared to 2016 and to approximately 33% by 2050.

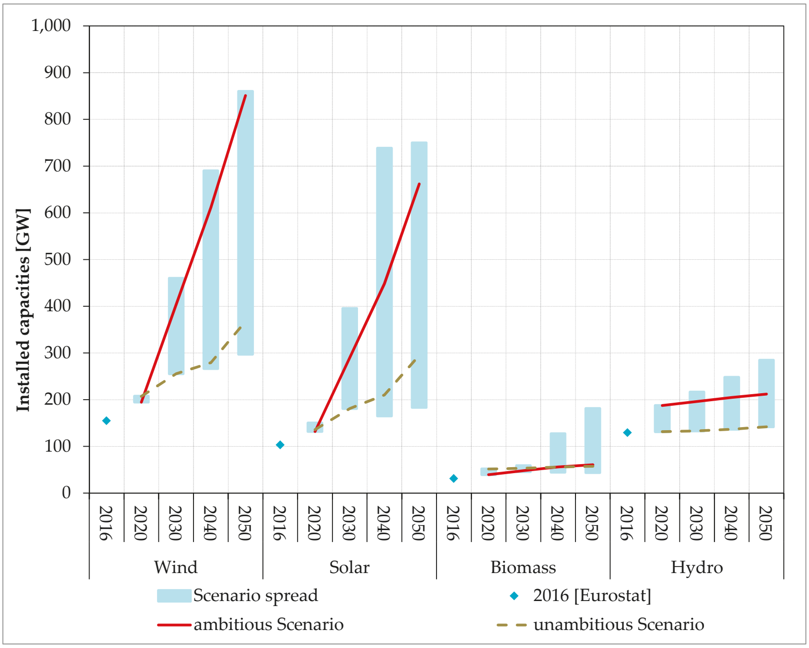

Figure 2. Comparison of RES-E capacities installed in EU28 countries based on References [5,29–31,33].

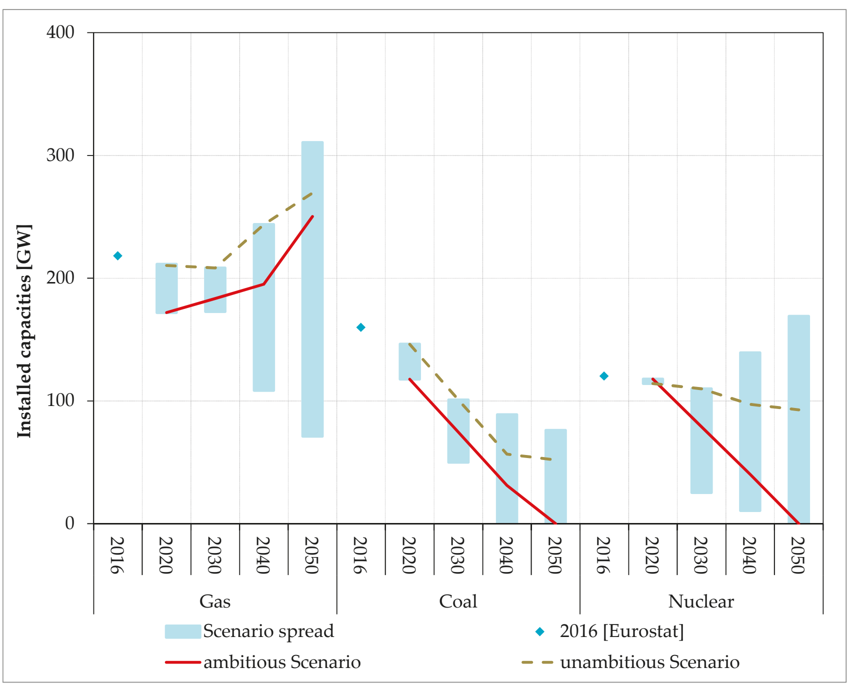

Figure 3. Comparison of conventional generation capacities installed in EU 28 countries based on References [5,29–31].

The scenarios differ even more in the assumptions on nuclear power development. While some scenarios assume an increase in nuclear power, most scenarios assume at least a slight decline. In the unambitious scenario, nuclear power capacities decline to approximately 77% for today's level. In the ambitious scenario, a European-wide nuclear phase-out is assumed.

2.2.2. German Scenario

The assumptions on the development of the German electricity market are based on scenario Klimaschutzszenario 95 (KS 95) from Reference [28]. Figure 4 shows the development of installed capacities and electricity demand for Germany. In order to end up with a more ambitious scenario in our analysis, we decided to further reduce the coal capacity for 2050 from 2.7 GW to 0 GW compared to the original scenario values. The nuclear phase-out [34] will be completed before 2030. By the year 2050, the installed wind capacity is expected to increase by a factor of 4 compared to the 2016 level and the solar capacity is expected to triple during this period. While biomass in the electricity sector will be of less importance, it is assumed that the installed capacities of hydro power (run-of-river and pumped storage) will double by 2050. Efficiency measures will dominate the development of electricity demand until 2030. After that, the demand for electricity will rise again due to new consumers such as heat consumers and electric mobility and will be about a quarter above the current level in 2050.

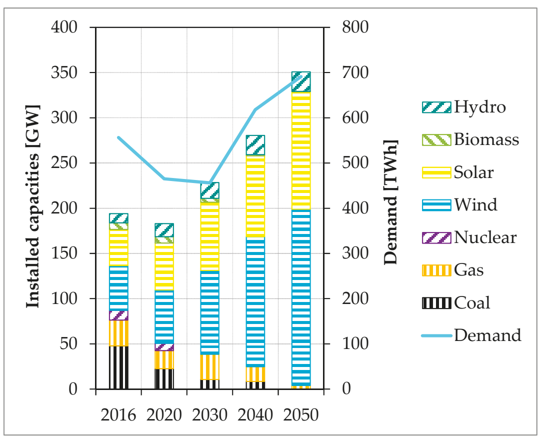

Figure 4. Electricity demand and installed capacities in Germany. Source: References [28,35].

2.3. Interconnector Scenarios

The integration of the European electricity system strongly depends on whether interconnector capacities develop, according to investment plans or whether investment hurdles slow down the process. Forecasts of net transfer capacities (NTCs) usually assume idealized developments of interconnection based on economic or technical needs, and do not explicitly take practical investment hurdles into account.

The Agency for the Cooperation of Energy Regulators (ACER) has identified significant delays for the projects of common interest (PCI). ACER [21] has shown that 75% of PCIs in the phase of "permitting" are delayed or rescheduled. Bureaucracy and a lack of social acceptance seem to be the main reasons for delays. Given high investment risks for large-scale cross-border projects, Roland Berger [19,36] has further argued that regulatory flaws and uncertainty about cost approval may present investment hurdles. A counter effect may result from economies of scale, especially learning curve effects both for investors and administration.

All these determinants of the net transfer capacities (NTC) development are more or less strongly related to the political ambitions of promoting a continued integration of the European electricity system. Accordingly, we distinguish between two integration scenarios. The high connectivity scenario reflects an ideal development of NTCs and draws on the original forecast data of eHighway 2050 scenario 100% RES [6]. Hence, in this scenario, we implicitly assume that potential investment barriers can be overcome. The lower connectivity scenario may be interpreted as a "business-as-usual" case, where issues of investment delays are not resolved. For this scenario, the original forecasts are adjusted downward to reflect slower NTC development (the methodology of how these adjustments are derived are given in Appendix B) Our adjustments lead to a regressive increase of the investment spread between the high and lower connectivity scenario (denoted ΔInv), which results in the downward-sloping curve for ΔInv, as shown in Figure 5.

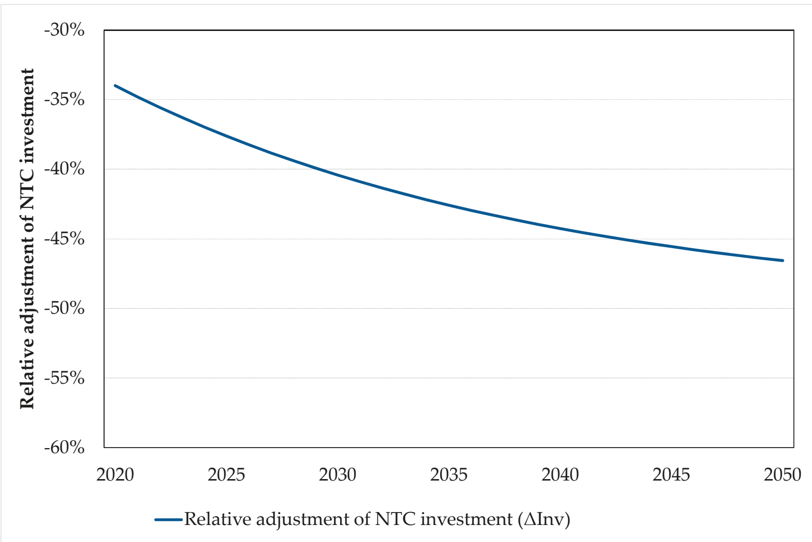

Figure 5. Development of relative NTC investment adjustment (own calculations and assumptions based on References [5,37]).

Figure 6 shows cumulated NTCs for the ENTSO-E area assumed in TYNDP 2018 [5] and eHighway 2050 [29]. In the period up to 2050, a significant increase in NTCs of up to six times of their current value is assumed. In addition to the expansion of cross-border lines, this also takes into account a higher availability of transmission lines for transnational electricity trading. According to Reference [38], the average NTC to thermal grid capacity ratio was 31% in 2016. This means that, on average, only 31% of physical cross-border transmission capacity was made available for transnational electricity trading. According to the EC's Communication on strengthening Europe's energy networks [39], at least 70% of thermal capacity must be made available to the cross-border market by 2025. If this adjustment was applied to the 2016 NTCs, the exchange capacities could be increased from approximately 57 GW to approximately 128 GW (see Figure 6).

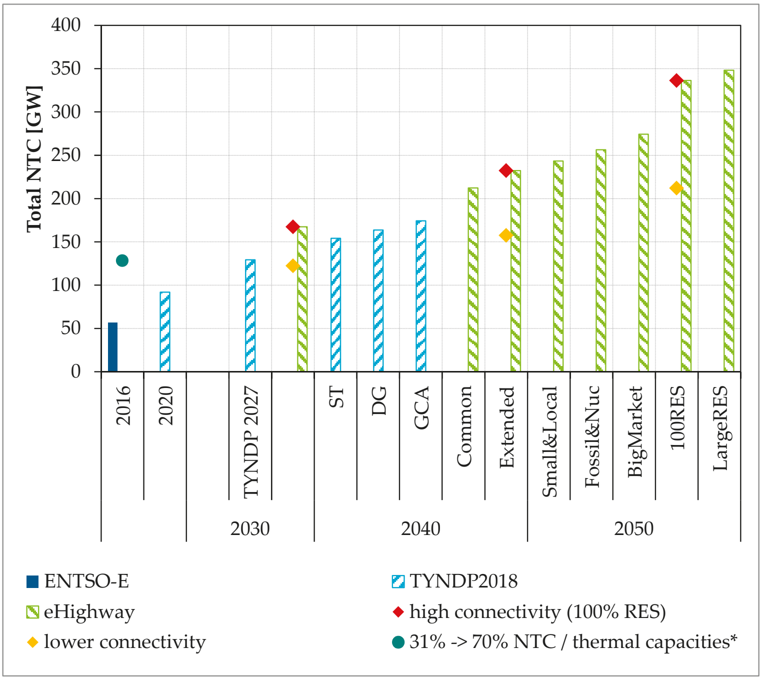

Figure 6. Development of total NTC in the ENTSO-E area [5,29]. *Increase of the NTCs due to a higher NTC to thermal grid capacity ratio: 2016: Ø 31% [38], 2025: min. 70% [39].

The high connectivity scenario is based on the values of eHighway 2050. For the scenario year 2030, there is no differentiation of NTC assumptions in this source. The extended scenario in eHighway 2050 and, thus, the scenario with the stronger NTC expansion is used for the year 2040. In the scenario year 2050, there is a clear spread between the eHighway scenarios. In this case, according to the electricity market scenario, the values of the 100% RES scenario were used. For the lower connectivity scenario, as described above, delays in the expansion of coupling capacities were transferred in accordance with the changes from TYNDP 2018 to TYNDP 2016 for the year 2020. Comparing these values with the data of TYNDP 2018, it can be seen that, in the high connectivity scenario, significantly higher values are applied, while, in the lower connectivity scenario, values are approximately at the level of TYNDP.

Figure 7 shows NTCs between the countries considered and their sum of export capacities in the high connectivity scenario for the year 2050. The cumulative increase in coupling capacities shown in Figure 3 is illustrated at country level. Germany, France, and the United Kingdom, in particular, have very strong networks with their neighboring countries, with cumulative export capacities of between approximately 70 and 120 GW.

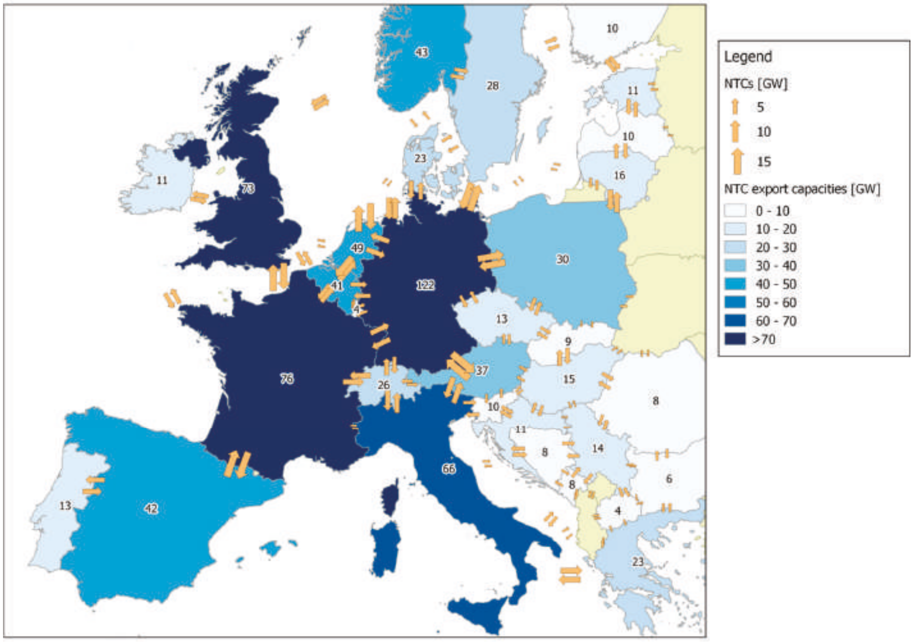

Figure 7. NTCs between the countries considered and their sum of export capacities in the high connectivity scenario for the year 2050. Source: Reference [29].

3. Results

This section presents the results of the examination of a delayed expansion of interconnector capacities. In this analysis, a strong interconnector expansion (high connectivity scenario) was compared with a delayed expansion (lower connectivity scenario), while generation capacities and electricity demand remain constant.

3.1. Import, Export, and Transit Flows

Figure 8 shows the development of electricity exchange between the modeled ENTSO-E countries and the transit flows for the lower connectivity and the high connectivity scenarios. As an indicator for electricity exchange, the sum of export flows between countries in the ENTSO-E area that was used. In line with the significant increase in NTCs, electricity flows between countries grow significantly in the scenario years. In the high connectivity scenario, the values increase to 12 times of the 2016 level by 2050. In the scenario year 2030, the reduced interconnection causes a 13% reduction in the European electricity exchange. In 2040, the reduced interconnection leads to a 25% reduction, and, in 2050, it brings a 31% reduction.

In order to determine the amounts of electricity, which are not consumed in the importing countries but are transmitted to third countries, the hours with simultaneous imports and exports per country were examined (The derivation logic is described in Appendix B). Figure 8 shows the sum of country-specific transit flows across all ENTSO-E countries considered. Transit flows through several countries, such as, for example, from Norway to Italy, are considered for each transit country. This value thus indicates the quantity of electricity that is routed through the individual countries. Transit flows in the ENTSO-E area increase significantly over the scenario years. In the high connectivity scenario, the values increase to 8.9 times the 2016 level by 2050. This increase is even more significant than the increase in the total exchange of electricity. This means that the expansion of interconnector capacities stimulates more electricity flows through transit countries. In the scenario year 2030, the reduced interconnection causes an 18% reduction of European transit flows. In 2040, it leads to a 30% reduction, and, in 2050, it brings a 36% reduction.

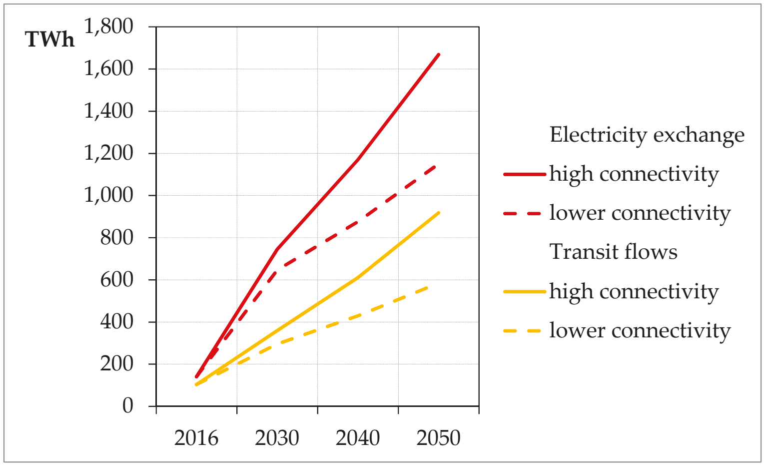

Figure 8. Electricity exchange and transit flows.

Figure 9 shows the development of electricity exchange and transit flows in relative terms to electricity demand. With this consideration, the development can be adjusted by the increase in electricity demand that is assumed in the scenarios. In the high connectivity scenario in 2050, on a country average, approximately 35% of electricity demand is traded between countries and, thus, produced abroad. The lower connectivity reduces this value by approximately 10 percentage points. A look at transit flows shows that, in 2050, in the high connectivity scenario, 20% of European electricity demand is routed through countries as transit flows, while this value amounts to only 13% with lower connectivity.

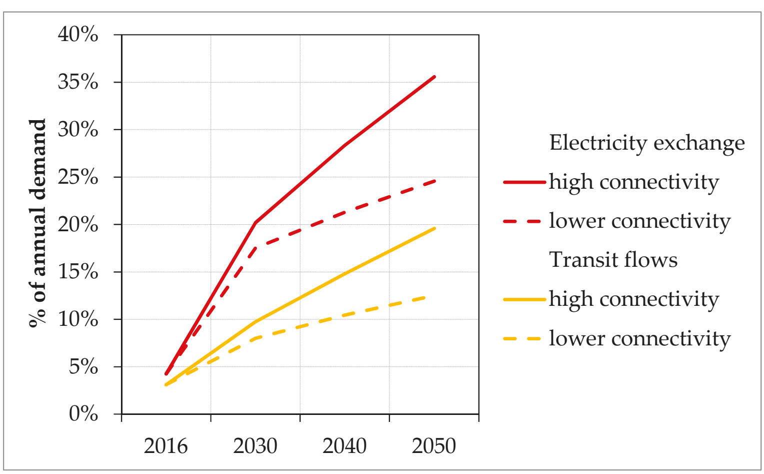

Figure 9. Electricity exchange and transit flows in relation to electricity demand.

3.2. Electricity Generation Mix

Figure 10 shows electricity generation with statistical data for 2016 and model results for the scenario years 2030, 2040, and 2050 (see Appendix D for the generation mix per country for the year 2050). By 2050, electricity generation from renewable energy technologies increases by approximately a factor of four compared to 2016. From the conventional technologies, only natural gas is used in the year 2050. Electricity generation from natural gas power plants declines in the high connectivity scenario by approximately 94% compared to 2016.

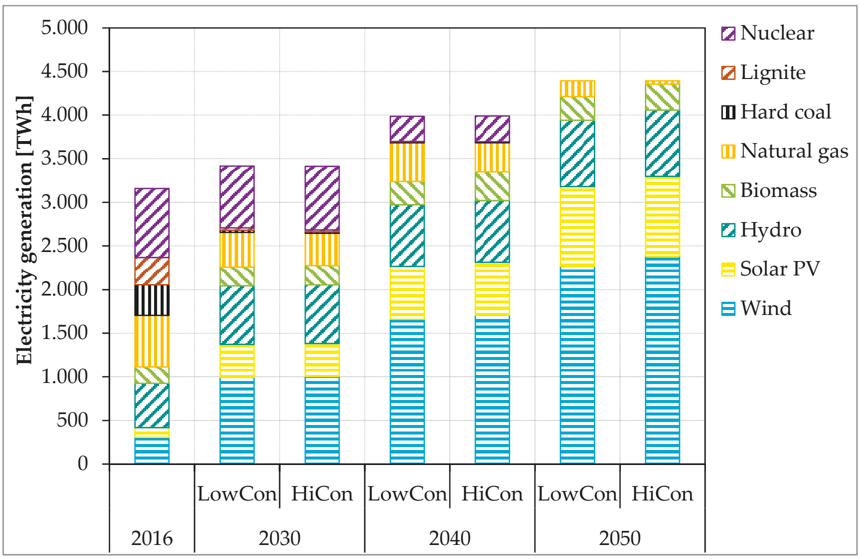

Figure 10. Electricity generation in the ENTSO-E area. Source: 2016 [32,35].

Lower connectivity leads to a reduced use of low-cost technologies such as nuclear power plants and RES technologies. In 2030, the shifts between fuels are still very small. In 2040, the missing electricity amounts are almost exclusively generated by natural gas power plants (approximately +110 TWh) and, in small quantities, by coal-fired power plants. In 2050, the delayed expansion of interconnectors leads to an increased curtailment of fluctuating RES technologies (cf. Table 1) and reduced generation of electricity from biomass. The reduced electricity production in 2050 can only be compensated by natural gas power plants (+142 TWh, cf. Figure 10).

Table 1. RES-E share and curtailment in the ENTSO-E area.

	2030		2040		2050	
	LowCon	**HiCon**	**LowCon**	**HiCon**	**LowCon**	**HiCon**
RES-E share of demand (%)	62%	63%	81%	84%	96%	99%
RES-E curtailment (TWh)	13	2	58	11	238	121

Figure 11 shows the change in electricity generation that results from the lower connectivity for the year 2050 on country levels. As already described in Section 3.1, the reduction in electricity exchange leads to an increased utilization of domestic electricity sources. It can be seen that the lower level of interconnectivity restricts trans-European exchange so that, in Northern Europe and Germany, renewables have to be curtailed and biomass capacities are used less, while, in Southern and Central Europe, natural gas power plants (and, in very small amounts, also biomass capacities) have to generate more electricity. Norway shows the largest decrease in RES-E integration. This can be attributed, in particular, to a significant reduction in electricity exports to Germany and the Netherlands (approximately 30%). Spain has the largest increase in electricity generation from natural gas-fired power plants. This can be attributed, in particular, to a reduction of approximately 70% of electricity imports from France.

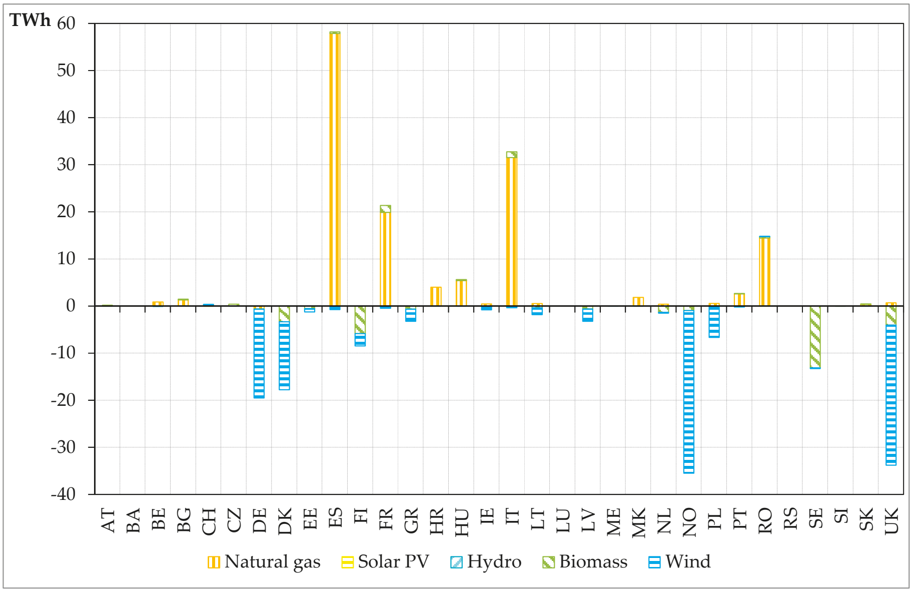

Figure 11. Change in electricity generation in 2050 due to lower connectivity levels.

3.3. CO_2 Emissions

Figure 12 shows CO_2 emissions of the electricity sector in the ENTSO-E area for 2016 and the scenario years 2030, 2040, and 2050.

By 2030, emissions in the high connectivity scenario will already have fallen by approximately 71% when compared to 2016. This significant reduction in CO_2 emissions results, in particular, from the sharp decline in coal-fired electricity generation. This decline is mainly due to the strong expansion of RES-E capacities. (A comparison with the TYNDP 2018 Sustainable Transition Scenario shows that emissions and coal electricity generation are much lower at similar coal capacities in 2030. The CO_2 prices in this study and in the Sustainable Transition scenario are at similar levels (87 € and 84 €) and cannot cause the difference. However, our study assumes a significantly faster expansion of RES-E capacities, which leads to a 10-percentage point higher RES-E share in electricity demand.) The lower connectivity leads to approximately 18.5 Mt (6%) higher CO_2 emissions, which results from a greater use of coal and natural gas power plants. This becomes necessary as more renewables are being curtailed and biomass and nuclear power plants can be used less (cf. Figure 10).

In the scenario year 2040, CO_2 emissions decrease by approximately 86% compared to 2016 (cf. Table 2). The effect of lower connectivity on CO_2 emissions, at approximately 37 Mt, is about twice as high as in 2030. In relative terms, emissions will increase by around 26% due to the lower connectivity. The reduction in the use of nuclear power plants (approximately 10 TWh) plays only a minor role compared to the decline in renewable generation (approximately 110 TWh). A similar change can be observed in fossil technologies. The decline in CO_2 neutral electricity generation is almost completely balanced out by natural gas power plants (approximately 110 TWh) and only to a marginal extent by coal-fired power plants (approximately 2 TWh) (cf. Figure 10).

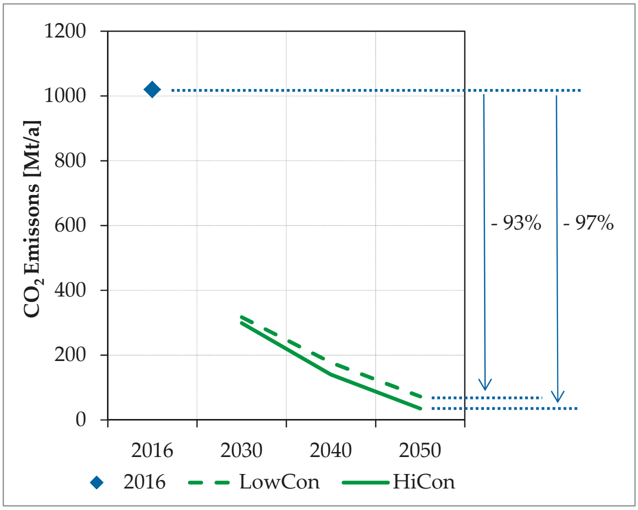

Figure 12. Development of CO_2 emissions in the ENTSO-E area. Source: 2016 [40,41].

Table 2. CO_2 emissions in the ENTSO-E area in 2016 and in the scenario years (absolute (Mt/a), effect of lower connectivity (Mt/a), and reduction compared to 2016 (%)). Source: 2016 [40,41].

	2016	2030	2040	2050
2016	1020			
LowCon (Mt/a)		317	177	72
HiCon (Mt/a)		299	140	35
LowCon-HiCon (Mt/a)		18.5	36.9	37.4
LowCon vs. 2016 (%)		69%	83%	93%
HiCon vs. 2016 (%)		71%	86%	97%

By 2050, a CO_2 reduction of approximately 97% when compared to 2016 is achieved. The effect of lower connectivity is, with approximately 37 Mt, roughly at the same level as in 2040. However, from a relative point of view, the reduced connectivity leads to more than a doubling of CO_2 emissions. This increase in emissions is caused by a shift from renewable to natural gas production of about 142 TWh.

3.4. Variable Costs of Electricity Generation

In order to evaluate the monetary impact of a delayed expansion of interconnector capacities, the variable costs of electricity generation were considered. This value is determined by the amount of electricity generated coupled with fuel and CO_2 prices. Investment costs and fixed costs are not considered in this analysis. Since no changes in the power plant fleet between the connectivity scenarios are assumed, the investment costs and the fixed costs for electricity generation also remain constant between these scenarios and can be neglected in the delta analysis.

Two opposing effects influence the development of variable costs of electricity generation over time. On the one hand, fuel and CO_2 prices rise significantly by 2050 (cf. Appendix B). On the other hand, the increasing share of renewable energies in electricity generation reduces costs. Table 3 shows the variable costs of electricity generation for the ENTSO-E area in billion €/a. Costs decline significantly over the years. Variable costs of electricity generation in the lower connectivity case are 45% lower in 2050 than in 2030, and, in the high connectivity case, the electricity generation's variable costs are 70% lower. The impact of lower interconnectivity increases from 5% higher costs in 2030 to 20% higher costs in 2040, to almost doubling the costs in 2050, caused by the less efficient use of the European power plant fleet resulting from the lower exchange of electricity described in Section 3.1. The increased use of natural gas power plants instead of renewable technologies described in Section 3.2 leads to the increase in variable costs of electricity generation, which can be seen in Table 3.

Table 3. Variable costs of electricity generation in the ENTSO-E area.

(bn €/a)	2030	2040	2050
LowCon	77.4	71.8	42.6
HiCon	73.9	59.7	22.2
LowCon-HiCon	3.5	12.1	20.5

Alternatively, the variable costs of electricity generation can also be stated per MWh of electricity generated (see Table 4). Due to the rising demand for electricity, this perspective leads to an even stronger reduction in costs over the years. In the lower connectivity scenario, costs fall by 57% between 2030 and 2050, and, in the high connectivity scenario, costs decline by 76%. The lower interconnectivity leads to an increase of variable costs of electricity generation of approximately 1 €/MWh in 2030, approximately 3 €/MWh in 2040, and approximately 4.4 €/MWh in 2050.

Table 4. Variable costs of electricity generation per MWh electricity produced in the ENTSO-E area.

(€/MWh)	2030	2040	2050
LowCon	20.9	17.4	9.1
HiCon	20.0	14.5	4.7
LowCon-HiCon	0.9	3.0	4.4

4. Discussion

This paper examines the effects of a delayed expansion of interconnector capacities between European countries. In the framework of this analysis, other input parameters, such as generation capacities and electricity demand, are not varied. In the following, approaches to compensate for a delayed grid expansion are discussed. This is followed by a detailed comparison of the results with the TYNDP 2018 "no grid" scenario.

Other studies discuss mainly two approaches as alternatives to grid expansion. More flexibility can be added to the system, or the geographical deployment of RES-E capacities can be oriented toward the distribution of electricity demand. Therefore, the question arises whether our results are due to a lack of these alternatives in our assumptions. If there is insufficient flexibility and RES-E is concentrated in specific areas, then the value of the grid expansion that we have shown could be largely driven by the assumptions.

First, with regard to the flexibility approach, METIS Study S1: Optimal flexibility portfolios for a high-RES 2050 scenario [42] provides a good benchmark. This study examined the need for flexibility in Europe with 80% RES share. Comparing the results of this study with our flexibility assumptions for the year 2040, in which an RES share of approximately 80% is achieved, it can be seen that the expansion of interconnectors is assumed to be roughly the same as in our lower connectivity scenario and that the pumped storage capacities are on a similar level. In order to avoid any restrictions resulting from a lack of flexibility, our assumptions regarding the electrolyser and battery capacities are significantly higher. In Reference [42], the demand response was considered another flexibility option, which is more than compensated for by our higher assumptions for battery capacities. The comparison of the considered flexibility options with the METIS Study indicates that flexibility options that compete with the flexibility of the grid have sufficiently been taken into account in our scenario analysis and that the effects of a lower grid expansion are not a result of a lack of such flexibility. Rather, the observed effects of a delayed expansion of interconnectors would increase further if fewer alternative flexibility options were considered. Second, a demand-driven distribution of RES-E can, to some extent, reduce the expansion needs of the European transmission grid (cf. [16]). If RES-E technologies are not distributed to the most favorable sites, this increases their levelized cost of electricity. According to Fuersch et al. [18], the higher costs for RES-E generation are not compensated for by the savings made in grid expansion, while DNV GL [16] argues that, with "decreasing costs of renewable electricity, the cost of grid expansion increasingly becomes a relevant factor, which may offset higher generation costs of RES-E that are deployed at less optimal geographical locations" (cf. [16] page 4). In the eHighway 100% RES scenario, renewables were distributed in Europe using distribution keys, which reflects both capacity factors and demand (cf. [6]). Thus, renewables were not distributed exclusively according to their generation costs, and our analysis already includes the mitigating effect on grid expansion, to a certain extent.

Our results can best be compared with the "no grid" scenario of TYNDP 2018 [24]. In this approach, for the scenario year 2040, no further grid expansion is assumed from 2020 onwards, while all other input data, such as power plant fleet or electricity demand, is correspond to the reference scenarios. Table 5 shows a comparison of the RES-E share in electricity demand and the NTC reduction between TYNDP 2018 and this study. It can be seen that, in this study, the RES-E share is comparatively high, while the relative NTC reduction is lower than in the TYNDP analysis. As has been shown in Figure 6, the planned expansion of interconnector capacity for 2040 in TYNDP 2018 is roughly at the level of the lower connectivity scenario. Therefore, in the high connectivity scenario, a significantly stronger expansion of interconnector capacities is assumed.

Table 5. Comparison of RES-E share in electricity demand and assumptions for NTC reduction in the TYNDP 2018 and this study. Source: Reference [24] and own calculation.

	Year	RES-E Share	NTC Reduction in the "No Grid" and Lower Connectivity Scenarios, Respectively
TYNDP 2018	2040	64%–80%	40%–47%
This study	2030	63%	27%
	2040	84%	32%
	2050	99%	37%

In the following, we compare our results for electricity exchange, electricity generation mix, CO_2 emissions, and variable costs of electricity generation with the TYNDP 2018 "no grid" scenario.

Our analysis shows that a reduced expansion of interconnector capacities limits European electricity trading. It reduces electricity exchange between 13% in 2030 and 31% in 2050. In the TYNDP 2018 "no grid" scenario, this analysis is given as net annual balance per region and can, therefore, not be directly compared. However, the "no grid" view also comes to the conclusion that "the enhanced grid leads to a much greater level of power transfer between countries" (cf. [24] page 19).

The electricity generation mix shifts toward technologies with higher generation costs due to the lower level of grid expansion. In our analysis, this effect is still relatively small in 2030, but increases by 2050, which is in line with the increasing RES-E expansion. This leads to an additional 47 TWh of RES-E curtailment in 2040 and 117 TWh in 2050. Gas-fired power plants compensate for the curtailed RES-E generation within Europe. In the TYNDP 2018 "no grid" analysis, the reduced grid expansion leads to approximately 156 TWh RES-E curtailment (cf. [24] page 22 f.). This stronger effect can be explained by the significantly stronger NTC reduction in the "no grid" scenario (cf. Table 5).

The changes in electricity generation lead to an increase in CO_2 emissions. Due to the small changes in the generation mix in 2030, the effect on emissions is still relatively small in this year. In our analysis, in both 2040 and 2050, the additional emissions caused by the delayed expansion of the grid amount to approximately 37 million tons. For the year 2050, this would mean a doubling of CO_2 emissions in the electricity sector. The stronger expansion of the grid can, thus, make a significant contribution toward reducing CO_2 emissions. As a result of the greater grid reduction, the TYNDP 2018 "no grid" analysis also shows a stronger increase in CO_2 emissions (+100 Mt) (cf. [24] page 23).

Due to the less efficient use of the European power plant fleet, the variable costs of electricity generation increase in the lower connectivity scenario. In our analysis, this increase amounts to 5% higher costs in 2030, 20% higher costs in 2040, and almost a doubling of costs in 2050. In addition to the overall stronger change in the electricity generation mix, this increase can be explained by two further elements. First, fuel and CO_2 prices rise over the years, so that the additional use of natural gas power plants has a greater impact on electricity generation costs. Second, the higher share of renewable energy reduces generation costs, so that the relative changes in costs are more pronounced.

If there is no grid expansion, there would be higher electricity generation costs, but, at the same time, there would also be cost savings due to lower grid expansion costs. These grid-related cost savings were not taken into account in this analysis since our focus was on the effects of grid expansion in high RES-E scenarios. It was also assumed that there would be a delay in the expansion and that the grid would, therefore, be expanded at a later date. In the TYNDP 2018 "no grid" analysis, the reduced expansion of the grid resulted in electricity prices that would lead to consumer costs about three times the cost for the additional expansion of the grid, as calculated in the baseline scenario (cf. [24] page 17).

5. Conclusions

This paper concludes that the expansion of interconnector capacities can not only ensure a more efficient use of the European power plant fleet in the European internal market and associated cost savings but can also make an important contribution toward greenhouse neutrality. These effects increase over the years. On the one hand, this is due to the assumption that the absolute capacities of delayed projects will increase over the years with increasing grid expansion, which leads, over time, to a growing difference between the high connectivity and lower connectivity scenarios. On the other hand, due to the expansion of renewables, the spatial balance made possible by the European electricity grid becomes increasingly important. This observation is also shown in the TYNDP 2018 "no grid" analysis where the strongest effects are determined for the scenario with the highest RES-E share (cf. [24] page 17). This means that grid expansions that are planned today and that may be motivated to a large extent by cost savings achievable in the internal European market, are still relevant in a future high RES-E world with ambitious CO_2 targets.

The identified effects of the delayed grid expansion can be interpreted as a conservative estimation. They would increase further with a lower level of alternative flexibilities such as batteries or power-to-gas. Compared to the assumptions in TYNDP 2018, a very strong expansion of interconnector capacities was assumed in the high connectivity scenario. As a result, the values of the lower connectivity scenario for 2030 and 2040 are approximately at the level of the TYNDP 2018 values. It can be assumed that, if the planned expansion of the grid was less pronounced, the restrictions on electricity exchange would become even more severe, and stronger effects would already become visible in the scenario year 2030.

Since both this paper as well as the TYNDP 2018 "no grid" analysis have shown the negative effects of a delayed expansion of interconnector capacities, the barriers for this expansion should be addressed. As described in Reference [20], the main obstacles are regulatory issues and acceptance problems. This is why a "simplified and standardized regulation" as well as a "strong and transparent consultation process in all stages" are proposed [20]. Bovet [43] additionally elaborates that the enforcement power of the two European legal instruments Projects of Common Interest and Ten-Year Network Development Plan should be strengthened, so that delays in the expansion of the European transmission grid can be addressed more effectively. In Reference [44], ENTSO-E and the Renewables Grid Initiative (RGI) describe how a lack of acceptance can be counteracted by "better projects." These "better projects" are characterized by "locally tailored, transparent, and participatory planning processes" [44].

Author Contributions: All authors contributed to the conceptualization of the research. D.R. took the lead in data curation, the analysis of the results, and in writing this paper. M.H. run the model software and wrote the model description in Section 2.1. R.M. developed the methodology to calculate the delay in NTC expansion and wrote the main part of Section 2.3. All authors have performed the validation of the results and have critically reviewed and edited the paper.

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Abbreviations

The following abbreviations are used in this paper.

a	annum (per year)
ACER	Agency for the Cooperation of Energy Regulators
bn	billion
CHP	combined heat and power plants
CO_2	carbon dioxide
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
GAMS	General Algebraic Modeling System
GW	gigawatt
h	hour
HiCon	scenario high connectivity
KS 95	Klimaschutzszenario 95
LowCon	scenario lower connectivity
Mt	megaton (1 million tons)
MW	megawatt
MWh	megawatt hour
NTCs	net transfer capacities
PCI	Projects of Common Interest
PV	photovoltaic
PtG	Power-to-Gas
RES	renewable energy source
RES-E	electricity from a renewable energy source
RGI	Renewables Grid Initiative
t	ton
TWh	terawatt hour
TYNDP	Ten-Year Network Development Plan

Appendix A

Data Availability

The data sets as described in Table A1 are available in a country-specific resolution under the following link: https://zenodo.org/record/3257495.

Table A1. Fuel price (€/MWh_{th}) and CO_2 price (€/t CO_2) scenario.

Data	Data Type	Unit	Input/Output
Demand	Hourly profiles	MWh	Input
Variable RES-E	Hourly profiles	MWh	Input
Power plant fleet	Capacities	MW	Input
NTCs	Capacities	MW	Input
CO_2 emissions	Annual data	Mt	Output
Variable costs of electricity generation	Annual data	M€	Output
Variable costs of electricity generation per generation unit	Annual data	€/MWh	Output
Electricity generation	Annual data	TWh	Output
Electricity export	Annual data	TWh	Output
Electricity import	Annual data	TWh	Output
Transit flows	Annual data	TWh	Output

Appendix B

Fuel and CO_2 Prices

Table A2 shows the fuel and CO_2 prices that were used for modeling. This data is based on Klimaschutzszenario 2050 [28].

Table A2. Fuel price (€/MWh_{th}) and CO_2 price (€/t CO_2) scenario. Source: Reference [28].

	2030	2040	2050
Oil (€/MWh_{th})	59	74	90
Gas (€/MWh_{th})	34	41	50
Coal (€/MWh_{th})	12	14	16
CO_2 Prices (€/t CO_2)	87	143	200

Dimensioning of Batteries and Power-to-Gas Facilities

Batteries and PtG facilities are dimensioned per country and implemented as one large plant per country, since the national grid is not considered. Table A3 shows the main characteristics of storage technologies. The assumed parameters of the batteries concerning charge, discharge, and storage capacity as well as the ratio of battery capacity to installed PV capacity are based on the scenario framework from the German Network Development Plan 2030 (2019) [45]. Deriving the electrolyser capacity of power-to-gas, a ratio of 10% concerning the generation capacity of PV and wind is assumed. No restrictions are considered either for the re-conversion into electricity as well as for the storage capacity for synthetic gas. At country level, 100% of peak load is available for re-generation and 100% of the annual demand is available as storage capacity. Total efficiency of the batteries for the coupling of charging and discharging is 95% in all scenarios. For PtG flexibility, total efficiency increases over the scenario years from 34% to 38% (calculation based on Reference [46]).

Table A3. Characteristics of storage technologies. Source: References [45,46] and own assumptions.

Technologies	Charge and Discharge Capacity	Storage Capacity	Total Efficiency
Battery	10% of installed PV capacity	10% of installed PV capacity × 1 h	95%
Power-to-Gas (PtG)	Electrolyser capacity: 10% of PV and wind generation capacity Reconversion into electricity: 100% of peak load	100% of total annual load	2030: 34% 2040: 36% 2050: 38%

Derivation of Transit Flows

As described in the following equation, the annual transit flows per country ($Trans_c$) are the sum of the hourly transit flows ($Trans_t$). Therefore, the amount of imports and exports must be distinguished on an hourly basis. If, in the respective country, more imports (Imp_t) than exports (Exp_t) are made, the export quantities can be interpreted as transit flows. If the inverse case is given, import quantities must be used.

$$Trans_t = \begin{cases} Exp_t & \text{if } Imp_t > Exp_t \\ Imp_t & \text{if } Imp_t < Exp_t \end{cases} \tag{A1}$$

$$Trans_c = \sum_{t=1}^{8760} Trans_t \tag{A2}$$

Derivation of the Lower Connectivity Scenario

To derive our lower connectivity scenario, we adjusted the original NTC forecasts–serving as the idealized high connectivity scenario–for practical investment hurdles that may slow down the actual development of interconnection capacities. Below, we describe the underlying methodology of these adjustments.

Unfortunately, existing data even for the recent past is limited, and data bases do not allow for a quantification of how overall political ambitions for system integration or specific barriers may affect future NTC delays for each of the interconnectors. Instead, we focused on data about currently known investment delays and derive future numbers based on plausible assumptions.

A comparison of NTC forecasts from TYNDPs 2016 [37] and 2018 [5] reveals that expected NTC investments have undergone a significant downward adjustment. Figure A1 shows the interpolated forecasts of the accumulated NTC investments after 2015, according to TYNDP 2016 (Inv_2016) and TYNDP 2018 (Inv_2018) for the whole ENTSO-E area until 2030.

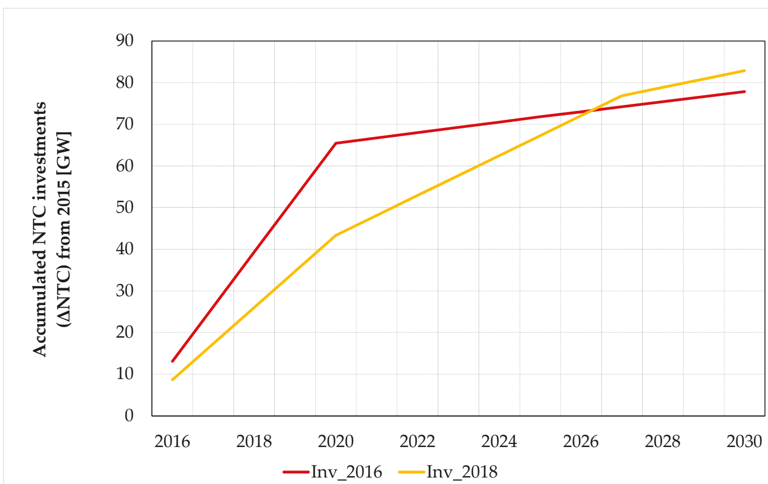

Figure A1. Accumulated NTC investments in the ENTSO-E area [5,37].

For the year 2020, the figure shows a relative reduction of accumulated investment numbers by 34%. In other words, between the two reported periods, total investment forecasts were corrected downward by one third of the original plans. Written formally, the relative adjustment of investments until 2020 ($\Delta \mathrm{Inv}^{2020}$) is given by the equation below.

$$\Delta \mathrm{Inv}^{2020} = \frac{\mathrm{Inv\_2018} - \mathrm{Inv\_2016}}{\mathrm{Inv\_2016}} \approx -34\% \tag{A3}$$

As the graphs show, investment forecasts in TYNDP 2018 catch up with the 2016 plans by 2026. We assume, however, that the main reason for this catch-up is that ENTSO-E calculations do not explicitly make assumptions about future investment delays. Instead of directly applying the specific numbers from the reports per year, we, therefore, decided to derive our own assumptions based on that we carry forward the relative adjustment for 2020 ($\Delta \mathrm{Inv}^{2020}$) to later years. There are two main reasons for picking the 2020 value as a starting point. First, 2020 is the only year for which both reports provide forecasts. Hence, using 2020 avoids the uncertainty of data interpolation. Second, given that 2020 is relatively close to the TYNPD 2018 reporting period, we expect that most of the investment delays were already known when the forecasts were made and are, therefore, implicitly represented in the data.

Regarding the future development of investment delays, however, we have to rely on plausible assumptions. Drawing on the findings of ACER [21] and Roland Berger [19,36], we expect that permitting and regulatory issues are going to remain the dominant factor of investment delays and hurdles. Given that the lower connectivity scenario does not imply a strong political will to overcome administrative investment hurdles, the ambitious NTC investment plans will most likely be subject to additional delays. Hence, we assume that the spread between forecasted and actual investments will increase over time. We assume a regressive increase of the investment spread, which result in the downward-sloping curve for ΔInv shown in Figure 5 in Section 2.3.

Appendix C

For a better overview, the scenario presentations in Section 2.2.1 have been simplified. The detailed figures and data derivations are presented below.

Scenario Comparison-Electricity Demand

Figure A2 shows the development of electricity demand for selected scenarios. During the period up to 2050, most of the scenarios show a significant increase in demand, which can be attributed to an overcompensation of efficiency measures by an increase of new electricity consumers, such as electric mobility or heat pumps.

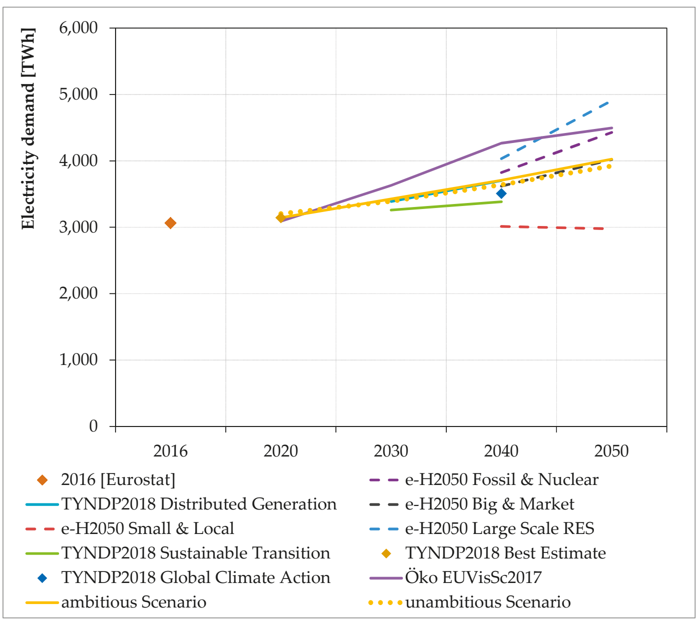

Figure A2. Annual electricity demand in EU28 countries. Sources: References [5,29–32].

Scenario Comparison-Renewable Generation Capacities

As shown in Figure A3, wind and solar capacities increase significantly in all scenarios. The ambitious scenario is located at the top and the unambitious scenario is located at the bottom of the scenario funnel. In the ambitious scenario, wind capacities are more than five times higher than in 2016, and solar capacities are more than six times higher. In the unambitious scenario, wind capacities more than double compared to 2016 and solar capacities almost triple compared to 2016.

While biomass capacities in most of the scenarios considered, double at most compared to the current level, in the scenario, 100% RES of the capacities undergo a six-fold increase. As described in Section 2.2.1, for the ambitious scenario, the values of the Big & Market scenario are used, as the increase of biomass capacities in the 100% RES scenario appears to be too strong, considering the competitive demand for land.

In most of the scenarios considered, hydro power capacities remain at about the current level or increase by half. In the 100% RES scenario, capacities more than double. In order not to overestimate the potential of hydro power, the values of the Big & Market scenario were also used here, since these are in the range of other scenarios. In addition, the assumed capacities were compared with the current level, and, for values that were lower, the current values were used. In the unambitious scenario, European hydro power generation capacities increase by approximately 10%.

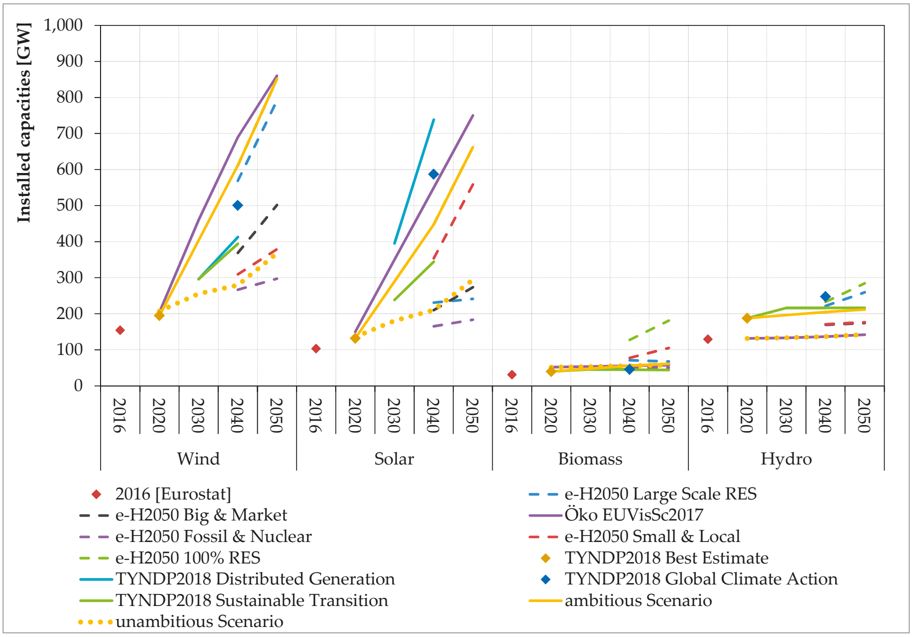

Figure A3. Installed RES-E capacities in EU 28 countries. Sources: References [5,29–31,33].

Scenario Comparison-Conventional Generation Capacities

Figure A4 shows that, in most scenarios, natural gas capacities show a slight decline over the next few years, which is followed by an increase until 2050 to provide for sufficient secured capacity. As described in Section 2.2.1, natural gas capacities in e-Highway 2050 scenario 100% RES decline significantly by 2050. Since lower biomass and hydro power generation capacities were assumed (taken from the Big & Market scenario) for the ambitious scenario as compared with the 100% RES scenario, significantly higher values—from the Big & Market scenario—were used for natural gas capacities. Thus, in the ambitious scenario, natural gas capacities in 2050 are approximately 15% above today's level. In the unambitious scenario, natural gas capacities increase by approximately 25% compared to today's level.

In all scenarios, coal capacities decline significantly from the current level, even though levels reached in the scenario year 2050 differ significantly. While the ambitious scenario assumes a European-wide phase-out of coal by 2050, the unambitious scenario assumes that coal capacities will decline to approximately 35% by 2040 compared to 2016 and to approximately 33% by 2050.

The scenarios differ even more in the assumptions on nuclear power development. While some scenarios assume an increase in nuclear power, most scenarios assume at least a slight decline. In the unambitious scenario, nuclear power capacities decline to approximately 77% of today's level. In the ambitious scenario, a European-wide nuclear phase-out is assumed.

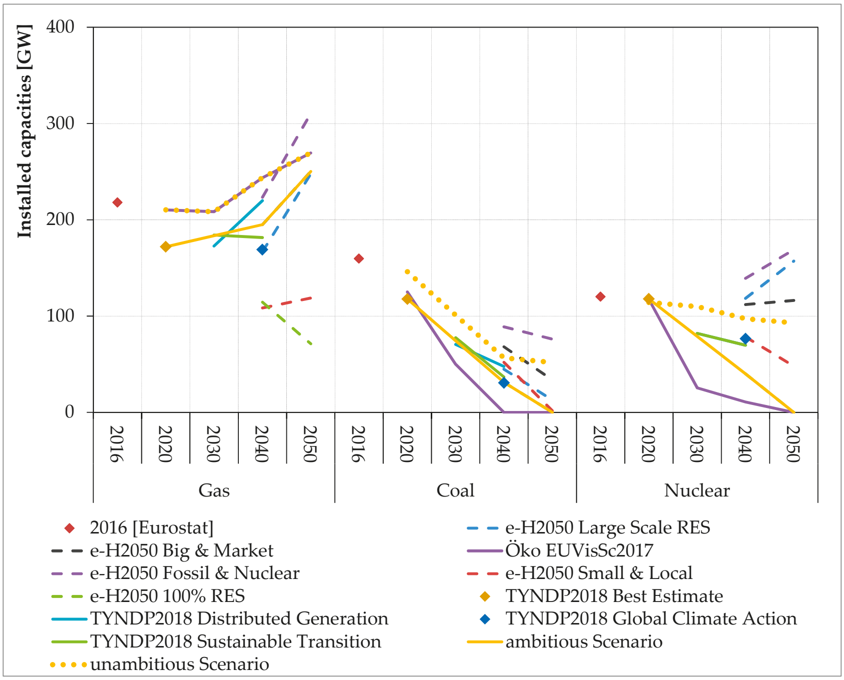

Figure A4. Conventional generation capacities installed in EU 28 countries. Sources: References [5,29–31].

Appendix D

Installed Capacities and Generation Mix 2050 per Country

In this appendix, the installed capacities (cf. Table A4) and the generation mix (cf. Tables A5 and A6) per country are presented for the scenario year 2050. As described in Section 2.2, the values for Germany are taken from Klimaschutzszenario 95 from Reference [28]. The capacities for the other countries are mainly based on scenario 100% RES from eHighway 2050 [29] (cf. Section 2.2 and Appendix C). Hydro power and biomass generation capacities increase very strongly in scenario 100% RES, which does not seem comprehensible from the perspective of natural restrictions respectively competing land use. Therefore, values of the eHighway 2050 Big & Market scenario [29] were used for these technologies. For hydro power generation capacities, it was further assumed that the installed capacities per country will not fall below the current level. In order to ensure that sufficient secure services are available, the size of natural gas capacities, which decrease significantly in the 100% RES scenario, was also taken from the eHighway 2050 scenario Big & Market. The derivation for power-to-gas and battery capacities is described in Appendix B.

Table A4. Installed capacities in GW, scenario year 2050. Source: References [28,29] and own assumptions.

	Natural Gas	Wind-On	Wind-Off	PV Solar	Bio-Mass	Hydro-Run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
AT	3.5	6.9	0.0	12.1	1.3	10.1	5.4	3.4	15.0	1.3
BA	0.0	2.6	0.0	1.3	0.0	1.3	1.8	0.0	2.2	0.2
BE	21.3	10.9	3.0	24.1	2.5	0.1	1.2	1.3	21.8	2.5
BG	2.3	4.4	0.0	5.4	0.8	0.7	2.8	1.4	6.6	0.6
CH	5.3	1.4	0.0	15.0	1.5	4.1	13.6	4.2	14.0	1.7
CZ	0.5	10.2	0.0	13.0	1.0	0.6	1.1	1.2	12.6	1.3
DE	3.9	98.3	27.2	98.6	0.4	4.3	6.3	15.7	79.1	12.3
DK	0.5	18.7	25.6	2.0	3.0	0.0	0.0	0.0	7.6	0.2
EE	0.5	8.1	0.0	0.8	0.3	0.0	0.0	0.5	2.3	0.1
ES	29.3	69.4	0.0	102.5	5.0	3.6	19.1	6.0	84.2	18.6
FI	5.8	29.5	0.0	5.8	3.0	4.1	1.7	0.0	14.9	0.6
FR	16.3	124.2	0.0	106.9	7.8	13.6	11.5	8.5	130.5	14.0
GR	3.0	25.9	0.0	15.1	1.0	0.4	3.3	1.6	12.4	2.7
HR	1.8	6.3	0.0	3.8	0.0	0.5	2.5	0.3	4.6	0.4
HU	4.0	4.9	0.0	14.0	1.3	0.3	0.3	0.0	10.2	1.6
IE	1.8	13.6	0.0	3.8	0.3	0.4	0.5	0.5	7.9	0.3
IT	46.8	41.3	0.0	101.0	8.0	11.4	8.5	7.7	70.8	15.8
LT	3.3	15.2	0.0	1.3	0.5	0.3	1.1	1.1	4.8	0.1
LU	0.0	0.7	0.0	1.0	0.0	0.2	1.3	1.1	1.3	0.1
LV	1.8	13.8	0.0	1.1	0.5	1.6	0.0	0.0	3.8	0.1
ME	0.0	0.5	0.0	0.5	0.0	0.0	1.4	0.0	0.6	0.1
MK	1.0	0.4	0.0	1.4	0.0	0.6	0.7	0.0	1.7	0.2
NL	26.8	15.0	15.9	22.2	2.8	0.0	0.0	0.0	26.7	2.1
NO	0.0	12.2	3.0	5.4	0.8	4.2	48.2	0.0	18.0	0.5
PL	3.8	81.9	0.0	24.2	2.8	1.0	0.4	2.5	30.7	2.4
PT	6.0	11.9	0.0	13.8	1.0	5.1	2.8	2.0	13.4	2.5

Table A4. *Cont.*

	Natural Gas	Wind-On	Wind-Off	PV Solar	Bio-Mass	Hydro-Run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
RO	5.8	4.8	0.0	11.0	1.5	3.8	4.0	0.0	12.9	1.2
RS	1.5	1.4	0.0	5.0	0.3	3.0	0.4	0.6	5.9	0.6
SE	0.0	24.2	3.0	8.9	2.8	0.0	18.5	0.0	23.8	0.9
SI	0.5	0.5	0.0	2.3	0.3	1.2	0.2	0.2	2.6	0.3
SK	1.8	5.2	0.0	6.9	0.5	1.8	0.4	1.3	4.4	0.7
UK	13.3	93.1	37.2	59.9	4.3	7.4	0.0	0.0	79.9	5.3
Sum	**211.4**	**757.4**	**114.9**	**690.3**	**54.6**	**85.7**	**159.0**	**60.9**	**727.2**	**91.5**

Table A5. Electricity generation in TWh, scenario year 2050 in the High Connectivity scenario. Source: own calculations.

	Natural gas	Wind-Onshore	Wind-Offshore	PV Solar	Bio-Mass	Hydro-run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
AT	0.0	13.6	0.0	13.4	7.5	40.1	6.6	3.6	1.1	0.4
BA	0.0	3.4	0.0	1.6	0.0	3.6	2.1	0.0	0.3	0.1
BE	1.1	24.2	10.7	24.8	14.5	0.3	1.2	1.7	3.0	0.8
BG	0.1	7.5	0.0	6.4	4.9	5.4	5.0	2.4	0.7	0.2
CH	0.0	0.9	0.0	17.5	9.6	26.3	24.4	6.9	1.8	0.6
CZ	0.1	20.4	0.0	13.3	6.0	1.0	1.3	1.3	1.5	0.4
DE	10.6	386.9	163.7	123.4	1.6	24.7	0.0	13.6	43.9	3.2
DK	0.0	53.2	55.2	2.1	3.4	0.0	0.0	0.0	9.1	0.0
EE	0.0	15.6	0.0	0.9	0.9	0.0	0.0	0.5	0.9	0.0
ES	16.2	145.0	0.0	186.1	32.4	13.5	24.5	10.0	15.8	5.4
FI	0.0	63.5	1.1	6.0	8.6	19.4	7.7	0.0	3.5	0.2
FR	1.8	272.7	3.6	140.1	48.6	43.6	17.1	13.9	25.3	4.6
GR	0.3	63.1	0.0	26.7	6.3	3.0	5.4	3.2	4.1	0.9
HR	0.3	8.5	0.0	4.3	0.0	4.1	3.6	0.5	0.8	0.1
HU	0.7	10.9	0.0	16.2	8.2	1.0	0.9	0.0	1.3	0.5
IE	0.1	40.8	0.0	3.3	1.4	1.0	0.9	0.8	2.3	0.1
IT	3.2	72.8	0.1	158.0	51.5	42.8	15.8	14.5	11.9	5.2
LT	0.0	31.8	0.0	1.3	2.4	0.9	2.1	1.2	1.9	0.0
LU	0.0	1.3	0.0	1.0	0.0	0.8	2.4	1.0	0.1	0.0
LV	0.1	25.0	0.0	1.2	1.8	4.3	0.0	0.0	1.4	0.0
ME	0.0	0.7	0.0	0.6	0.0	0.2	1.6	0.0	0.1	0.0
MK	0.2	0.4	0.0	1.7	0.0	1.8	2.9	0.0	0.1	0.1
NL	0.0	47.8	59.7	20.6	15.5	0.1	0.0	0.0	6.3	0.6
NO	0.0	48.6	12.8	5.3	1.0	18.7	214.6	0.0	0.6	0.1

Table A5. *Cont.*

	Natural gas	Wind-Onshore	Wind-Offshore	PV Solar	Bio-Mass	Hydro-run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
PL	0.2	128.9	0.0	23.6	14.5	4.8	0.7	2.7	9.7	0.7
PT	1.0	31.6	0.1	25.4	6.4	13.6	3.5	3.4	2.4	0.8
RO	0.8	7.5	0.0	12.4	9.8	14.6	6.0	0.0	1.1	0.4
RS	0.0	1.7	0.0	5.7	1.7	8.9	1.9	1.1	0.4	0.2
SE	0.0	49.6	12.5	8.8	14.0	0.0	76.3	0.0	1.5	0.2
SI	0.0	0.6	0.0	2.7	1.6	4.4	0.3	0.3	0.3	0.1
SK	0.2	7.0	0.0	7.4	3.3	5.4	0.8	2.3	1.1	0.3
UK	0.0	333.1	143.7	52.8	21.5	22.3	0.0	0.0	27.4	1.9
Sum	**36.9**	**1918.4**	**463.1**	**914.4**	**298.5**	**330.7**	**429.6**	**84.9**	**181.5**	**28.1**

Table A6. Electricity generation in TWh, scenario year 2050 in the Lower Connectivity scenario. Source: own calculations.

	Natural Gas	Wind-Onshore	Wind-Offshore	PV Solar	Bio-Mass	Hydro-Run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
AT	0.0	13.6	0.0	13.4	7.6	40.1	6.6	4.0	1.4	0.4
BA	0.0	3.4	0.0	1.6	0.0	3.6	2.1	0.0	0.2	0.0
BE	1.9	24.2	10.7	24.8	14.4	0.3	1.2	1.9	4.0	0.8
BG	1.5	7.5	0.0	6.4	5.1	5.4	5.0	1.9	0.4	0.2
CH	0.0	0.9	0.0	17.5	9.9	26.3	24.4	5.9	1.0	0.5
CZ	0.1	20.4	0.0	13.3	6.3	1.0	1.3	1.4	1.9	0.4
DE	10.0	380.2	151.5	123.4	1.6	24.7	0.0	14.4	57.0	3.2
DK	0.0	51.6	42.4	2.1	0.1	0.0	0.0	0.0	8.9	0.0
EE	0.0	14.9	0.0	0.9	0.3	0.0	0.0	0.5	1.1	0.0
ES	74.0	144.3	0.0	186.1	32.7	13.5	24.5	8.7	9.0	5.0
FI	0.0	61.1	0.9	6.0	2.7	19.4	7.7	0.0	4.1	0.2
FR	21.7	272.3	3.5	140.1	50.0	43.6	17.1	12.1	17.4	4.0
GR	0.3	60.5	0.0	26.7	5.7	3.0	5.4	3.0	4.4	0.9
HR	4.3	8.5	0.0	4.3	0.0	4.1	3.6	0.4	0.5	0.1
HU	6.1	10.9	0.0	16.2	8.4	1.0	0.9	0.0	0.8	0.4
IE	0.6	40.1	0.0	3.3	1.2	1.0	0.9	0.8	2.2	0.1
IT	34.7	72.4	0.1	158.0	52.7	42.8	15.8	12.4	7.9	4.6
LT	0.6	30.3	0.0	1.3	2.0	0.9	2.1	1.4	2.5	0.1
LU	0.0	1.3	0.0	1.0	0.0	0.8	2.4	1.1	0.1	0.0
LV	0.0	22.4	0.0	1.2	1.2	4.3	0.0	0.0	2.0	0.0
ME	0.0	0.7	0.0	0.6	0.0	0.2	1.6	0.0	0.1	0.0
MK	2.0	0.4	0.0	1.7	0.0	1.8	2.9	0.0	0.1	0.1
NL	0.4	47.8	59.6	20.6	14.1	0.1	0.0	0.0	7.4	0.7
NO	0.0	26.9	0.0	5.3	0.0	18.7	214.6	0.0	0.0	0.0

Table A6. *Cont.*

	Natural Gas	Wind-Onshore	Wind-Offshore	PV Solar	Bio-Mass	Hydro-Run	Hydro-Turbine	Pumped Storage	Power-to-Gas	Batteries
PL	0.8	122.3	0.0	23.6	14.4	4.8	0.7	3.0	12.0	0.7
PT	3.6	31.5	0.1	25.4	6.5	13.6	3.5	3.1	1.7	0.7
RO	15.2	7.5	0.0	12.3	10.1	14.6	6.0	0.0	0.7	0.3
RS	0.0	1.7	0.0	5.7	1.7	8.9	1.9	0.9	0.3	0.2
SE	0.0	49.5	12.4	8.8	0.9	0.0	76.3	0.0	2.0	0.1
SI	0.0	0.6	0.0	2.7	1.7	4.4	0.3	0.3	0.1	0.1
SK	0.6	7.0	0.0	7.4	3.3	5.4	0.8	1.8	0.7	0.2
UK	0.7	329.1	118.0	52.8	17.4	22.3	0.0	0.0	30.9	1.9
Sum	**179.0**	**1865.4**	**399.1**	**914.4**	**272.0**	**330.7**	**429.6**	**78.9**	**182.5**	**26.0**

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