How to meet EU GHG emission reduction targets? A model based decarbonization pathway for Europe's electricity supply system until 2050

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Abstract

Globally, due to industrialization, GHG emissions continue to increase. This is despite the existing scientific and political consensus to fight human-induced climate change. To reverse this trend, viable, cost-effective decarbonization pathways are needed. We focus on the European power supply system and demonstrate the techno-economic feasibility of reaching the EU's mitigation targets by 2050. We show that a transition from conventional to renewable- based power supply systems is possible for the EU even with a politically driven nuclear power phase-out. We provide a guideline for European stakeholders that shows how to transform their power generation systems. By following our recommendations, the EU can be a role model for other countries and regions moving towards decarbonization. Our work is guided by two main motivations:

- How can the transition of Europe's power system be modeled adequately?
- What is the techno-economically optimal transition pathway for meeting the EU GHG power sector emission targets by 2050?

A comparison of power system models has revealed a need for a combined short and long-term simulation tool that includes the principal power generation, storage and transmission technologies being considered in Europe. We adapted and applied the linear model *elesplan-m* to simulate a techno-economically optimized decarbonization pathway for 18 interconnected European regions and found that meeting the EU's reduction targets, *i.e.* reducing the GHG emissions from 1,300 to 24 Mt CO2eq per year by 2050, can be achieved by large-scale capacity investment in renewable energy sources (RES). The levelized cost of electricity (LCOE) would increase from 6.7 to 9.0 ctEUR/kWh and investments of 403 billion EUR would be necessary during the 34 year period analyzed. In 2050, the resulting power supply system is largely composed of wind power (1,485 GW) and PV (909 GW), which are supported by 150 GW hydro power and 244 GW gas power. In addition, 432 GW of storage and 362 GW of transmission capacity are required to temporally and spatially distribute electricity.

This work provides not only a feasible concept for a decarbonized power supply system, but shows also the implementation steps necessary to make the transition to that system cost-effective.

Keywords: Decarbonization, transition pathway, power system modeling, GHG emission mitigation, renewable energies

1. Introduction

1.1. Motivation

A major challenge for humanity in the 21st century is to reduce anthropogenic greenhouse gas (GHG) emissions in order to fight climate change[1]. Climate change and global warming are likely to lead to more

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extreme weather events as well as harvest failures and rising sea levels, all of which cause enormous damage and economic loss. Since industrialization began in the 19th century, annual GHG emissions have been increasing steadily and a turning point is not in sight [2]. Heat and electricity production account for 25 % of all GHG emissions [3].

To address the problem of human-driven climate change, 195 UNFCCC participating member states and the European Union agreed at the 2015 United Nations Climate Change Conference (COP 21) in Paris to increase their mitigation efforts [4]. As part of its response, the EU announced ambitious reduction targets:

> By 2050, the EU aims to cut its emissions substantially by 80 to 95 % compared to 1990 levels as part of the efforts required by developed countries as a group. [5]

The most stringent emission targets are set for the power generation sector, ranging from 93 to 99 % relative to 1990 levels. By setting these targets, the EU has committed itself to a decarbonization of Europe's electricity supply system [6].

1.2. Problem

Decarbonization of Europe's power supply sector while ensuring reliability, availability and cost-competitiveness of supply is a highly complex task. This transition cannot happen suddenly, but needs a well-designed transition pathway to meet social, political, ecological and economic expectations [7].

Policy makers need appropriate advice by energy experts. Such consultancy requires methods to assess feasible future power system configurations. Different studies have provided concepts for 100 % renewable energy supply systems (cf. [8, 9]), but so far a comprehensive analysis of the transition pathway for the entire European power system has been lacking. Realistic and detailed yet fast computing models are required to simulate and optimize such transition pathways.

Such power system models should be as simple as possible and as realistic as necessary. This means the required model must reflect all relevant power generation and storage technologies as well as transmission lines connecting different supply regions [10]. These power generation technologies include coal and gas-fired power plants, nuclear power plants and the major renewable sources for power generation in Europe - wind, solar and hydro power. In addition, short-term and seasonal energy supply characteristics must be considered by simulating reference years in hourly time steps as well as long-term characteristics of investment and implementation pathways. The challenge to amalgamate long-term energy system strategy planning with short-term dispatch modeling representing fluctuating power generation of RES and energy storage technologies is described by Pfenninger et al. [11]. Currently, none of the available power system models meets the requirements for simulating a least-cost decarbonization pathway for Europe; in particular, the linkage between short and long-term modeling is missing [12]. To fulfill these requirements, a new power system model is needed.

In our paper, we address the following research questions:

- How can the transition of Europe's power system be modeled adequately?
- What is the techno-economically optimal transition pathway for meeting EU GHG emission targets within the power sector by 2050?

To answer these questions, we developed and improved a power system model. This model, *elesplan-m*, builds on a series of models developed at the Reiner Lemoine Institut (RLI) [13, 14, 15]. In this paper, we used *elesplan-m* to simulate Europe's power supply system and to find optimized transition pathways. Section 2 contains a discussion of requirements for the power system model and a literature review. The *elesplan-m* model is described in detail in section 3. In section 4, we present the results of the modeling and the application of *elesplan-m* in Europe's power supply system to identify the most effective GHG emission reduction pathway, with discussion and conclusions in sections 5 and 6, respectively.

2. Theoretical background - Power system modeling

2.1. Model requirements

A power system model that is suitable to respond to the research questions of this paper must fulfill certain requirements. First, the scope must include power generation technologies currently operating in Europe in order to reflect present and potential future power generation mix. This includes conventional generation such as coal, gas and nuclear power, and renewable generation such as hydro, wind and solar PV power. Technologies with shares less than 5 % of annual generation [16] are neglected. Next, storage technologies with differing time horizons must be implemented in the model in order to address future volatility of renewable energy sources (RES) feed-in and associated balancing needs. Such technologies include battery storage, pumped hydro storage and/or power-to-gas systems [17]. Finally, a model of a large-scale system such as the European power supply system must consider inter-regional exchange of electricity. This means that transmission capacity as well as the net electrical energy exchanged for each simulation step should be analyzed.

The model should respond to short-term effects in order to ensure security and system adequacy of future power supply [18]. Power generation technologies whose power output depends upon meteorological conditions require an accurate temporal modeling in at least hourly time steps for one reference year [19]. Characteristics of power generation of those technologies are thereby considered in detail. In addition to short-term modeling, it is necessary to include long-term investment cycles in the model that enables it to change power supply system capacities. This means power generation, storage and transmission capacity can be added or withdrawn at five-year intervals. Pfenninger et al. stress that there is a demand for amalgamation of long-term energy system planning and short-term operational modeling—considering challenges arising from fluctuating RES and the increased demand for flexibility while planning future power supply systems [11].

Finally, the model must be able to analyze GHG emissions and build emission reduction pathways based on certain reduction objectives.

2.2. *Comparison of existing models*

Connolly et al. and Pfenninger et al. provide a thorough review of existing energy system research tools [20, 11]. The following simulation model comparison extends their work. We consider power system models URBS-EU [21, 9, 22], LIMES-EU+ [23, 24, 25, 26], DIMENSION (ext. version) [27, 28, 29] and Becker et al. [30].

Becker et al. employ a simplified model including wind and PV power only [30]. In the models URBS-EU, LIMES-EU+ and DIMENSION, generating technologies are aggregated in different ways. Nevertheless, all these models are suitable for modeling Europe's power supply system. Energy storage technologies needed to realize high RES penetration are implemented differently in the presented power system modeling approaches: Becker et al. just use a generic balancing unit, URBS-EU simulates pumped hydro storage (PHS) only, whereas multiple storage technologies are considered within LIMES-EU+ and DIMENSION. All models shown in Table 1 have in common that they use a spatial resolution in which smaller countries are aggregated to regions. Power exchange between countries or regions is represented by aggregating single transmission capacities to representative capacities. Fürsch et al. go one step further and apply the market model DIMENSION at the country level iteratively with an *optimal power flow* model of Europe's transmission grid [27]. This provides a detailed picture of transmission grid extension and its related cost, and proves the *n-1 stability criterion*.

There are two different approaches to temporal representation. URBS-EU and Becker et al. apply discrete time steps which are consecutively represented in hourly resolution, while LIMES-EU+ and DIMENSION apply a time-slice approach where representative time slices reflect short-term variations in supply and demand. The latter can significantly lower computational cost but may lead to reduced accuracy [31]. For long-term modeling, URBS-EU simply plans one totally new power system, applying a so-called *green field* approach, meaning the system is built from scratch without considering the implementation pathway. Becker et al. define power system capacities exogenously to the model and analyze performance in simulation. A pathway of capacities is obtained by fitting historic capacity expansion data to political RES development targets in individual countries. LIMES-EU+ and DIMENSION use an inter-temporal modeling approach with *decision years* every 5 or 10 years. LIMES-EU+ and DIMENSION consider GHG mitigation targets in the power sector to a final level of -80 % (DIMENSION) or -90 % (LIMES-EU+) relative to 1990 levels in the year 2050. URBS-EU does not employ such a constraint [22].

Other, similar methods exist beyond the models examined here: Scholz modeled Europe's power supply system with focus on spatial potential and cost of RES [32]. Bussar et al. analyzed large-scale integration of RES in the European power system, applying a *green field* approach based on heuristics to determine cost-optimal power system configurations for 2050 [33, 8]. Becker et al.'s modeling approaches build on previous modeling that can be categorized as *weather-driven energy system modeling* [34, 35, 36].

URBS-EU is not suitable for this work because it operates from greenfield, while the tool of Becker et al. is too simplified with respect to generation and balancing technology representation. LIMES-EU+ and DIMENSION are more suitable because they include long-term energy system planning, sufficient technology representation (including energy storage systems) and transmission modeling, as well as the option to map GHG mit-

Table 1: Analysis of current existing energy system models with respect to our stated requirements. Numbers in parentheses indicate number of technologies considered.

Existing models	URBS-EU	LIMES-EU+	DIMENSION (ext. version)	Becker et al.
Power generation technologies	Nuclear, Coal (2), gas (2), oil (2), hydro, biomass, PV, CSP, wind (2)	Nuclear, Coal, Gas, Hydro, Biomass, Wind (2), PV, CSP	Nuclear, Coal (2), gas, oil, hydro, biomass, PV, CSP, wind (2), geothermal, imports, other	Wind, PV
Storage technologies	PHS	Day/night, day to day, CSP	PHS, CAES	generic balancing
Inter-regional power exchange	yes, aggregated	yes, aggregated	yes, aggregated	aggregated, NTC
Spatial resolution	(sub-)country	20 regions EU-MENA	EU-27 (country level)	EU+ (country level)
Short-term modeling	hourly, 1 year	49 time slices per year, 6 h	24 time slices per year, 4 h	hourly, 8 years
Long-term modeling	*green field planning*	inter-temporal, 5-year steps	inter-temporal, 10-year steps	extrapolation
GHG emission constraints	no	-90 % in 2050	-80 % in 2050	no
Other constraints		RES quota		
Source	[21, 9, 22]	[23, 24, 25, 26]	[27, 28, 29]	[30]

igation targets along a selected pathway. Our research work is designed to analyze the potential of wind and PV power in particular, to meet Europe's power demand in coming 35-year period while meeting the stated GHG reduction targets. In addition to high-resolution time series for RES generation, we must include energy storage technologies addressing both short-term and long-term storage demand. According to Merrick, it is not possible use a time-slice based modeling approaches when storage is included in the model because the chronological relationship between time-steps has to be maintained [31]. Moreover, the temporal resolution of only 6 hours (or 4 hours, in the case of DIMENSION) cannot show the short-term volatility of supply that is typical of RES.

Since none of these models meet all our requirements, we developed a new model - *elesplan-m* - which combines several of their positive characteristics.

3. Methodology – Power system model *elesplan-m*

Inspired by current research in energy system modeling, we developed and subsequently applied the power system model *elesplan-m* to assess long-term GHG mitigation strategies in the European power sector. *elesplan-m* is designed to reveal least-cost system transformation pathways from a social-planning perspective. It analyzes feasible power system configurations which meet mitigation targets, focusing on RES power generation and flexibility technologies such as energy storage and transmission capacities.

The techno-economically optimized transition pathway is identified by analyzing investment and other costs for new generation, storage and transmission capacity. A dispatch strategy based on minimal system operating costs, combined with cost-optimal investment decisions, allows short-term modeling of reference years and the optimization of inter-regional power exchange and storage capacity. Additionally, long-term modeling in 5-year steps—we call these *decision years*—allows realistic assessments of least-cost pathways.

3.1. Components and technologies

The power system model *elesplan-m* includes generation, energy storage and transmission technologies. Specifically, this includes coal, gas (open (OCGT) and combined (CCGT) cycle power plants) and nuclear power plants, reflecting Europe's conventional power generation inventory, and hydro, wind and solar power as the principal forms of RES. Fossil-fueled power generation technologies equipped with carbon capture and storage (CCS) are not considered in the model, because earlier research findings show that CCS is of limited utility for greenhouse gas (GHG) mitigation [37, 38].

In modeling, we distinguish between conventional and renewable technologies. RES technologies' power generation depends on meteorological conditions. Thus, its maximum power generation capability in each time-step depends upon the currently available RES and the installed capacities; it is dispatchable only to the extent that it can be curtailed. In contrast, conventional power plants are modeled as fully dispatchable and can flexibly deliver power on demand within operational constraints.

Three energy storage technologies are represented in *elesplan-m*: batteries, pumped hydro storage (PHS) and power-to-gas (PtG), which is comprised of gas storage and subsequent re-electrification via conventional gas power plants. Representation of storage technologies in the model is limited to efficiency consideration of charge and discharge. This complex process[1] (which is described in detail in Refs. [39, 40]) is reduced to a single efficiency parameter reflecting accumulated losses in several process steps that are not explicitly modeled. Further, the CO_2 source is assumed to be cost-neutral. CO_2 related cost are discussed by Reiter et al. [41].

For each technology, plants are aggregated to a single generic power plant or storage system in each region. Similarly, transmission grid capacities are aggregated to a single transmission capacity between each of the regions. Each of the accumulated transmission capacities reflect the inter-regional power exchange.

Figure 1 illustrates the presented power system technologies and related potential power flows.

3.2. Structure and temporal resolution

Short- and long-term effects are evaluated using two approaches. The transition pathway is explored by analyzing *decision years* in 5-year steps with *elesplan-m*. In each *decision year*, new investment choices may be made after decommissioning existing plants which have reached their expected lifetime. The capacity mix of components and technologies is optimized to meet the respective GHG emission reduction targets.

We define an optimal system as one having the lowest levelized cost of electricity (LCOE) (which comprises cost of generation, transmission and storage) given certain technological constraints. From a Europe-wide systems perspective, this means cost-optimal investments are determined by analyzing power generation and storage capacity of each region and exchange capacities among the connected regions to find the overall lowest LCOE. Existing or additional future capacities are transferred from one *decision year* to the next *decision year* according to the respective lifetime of each technology. This allows the inclusion of existing capacities in the modeling of future energy supply scenarios resulting in a more realistic transition pathway.

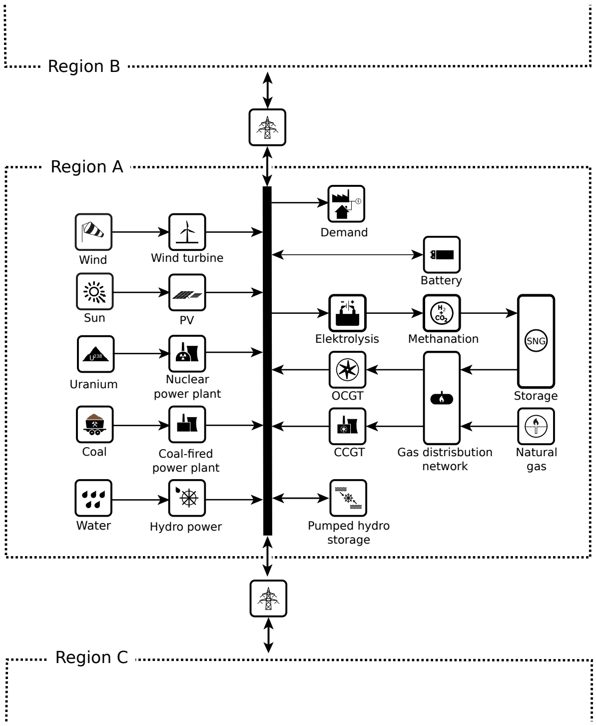

Figure 1: Power generation, energy storage and transmission technologies of *elesplan-m* and respective power flows. Technologies are represented per modeled region connected by representative transmission capacity.

In each *decision year*, the electricity dispatch of each single region and of all inter-regional connections is simulated in hourly increments. Fluctuating RES can be properly reflected at this time resolution. Any needs for short-term balancing power and storage capacity are made apparent, while it is ensured that the suggested system configurations meet the demand at every hour of the year. Dispatch is determined on an one-hourly temporal basis as depicted in Equation 1.

$$\sum_i E^{\text{elec}}_{\text{gen},i,r,t} + E_{\text{trans},r,t} + E^{\text{discharge}}_{\text{storage},i,r,t} = E_{\text{demand},r,t} + \sum_i E^{\text{charge}}_{\text{storage},i,r,t} + E^{\text{in}}_{\text{PtG},r,t} + E_{\text{curtail},r,t} \quad (1)$$

Annual GHG emissions are limited by an emission

[1] that consists of electrolysis, H_2 buffer storage, CO_2 source and the methanation unit

cap (Equation 2), which is one of the constraints in the model. Other constraints include fuel consumption, capacity expansion, energy storage and transmission operation (cf. Appendix A).

$$\sum_i \sum_r \sum_t \left(\sigma_i \cdot \left(P_{\text{cap,new},i,r} + P_{\text{cap,exist},i,r}\right) + \rho_i \cdot E^{\text{elec}}_{\text{gen},i,r,t}\right) \leq \Upsilon \quad (2)$$

Combining these short and long-term modeling approaches helps us identify a least-cost transition pathway. This is expressed as a linear optimization problem with a representation of an ideal power market with perfect foresight and perfect competition. Dispatch and required investments in new capacity are optimized following the objective function shown in Equation 3.

$$min \sum_r \left(\sum_i \left((Capex_{i,r} \cdot CRF_i + Opex_{\text{fix},i,r}) \cdot P_{\text{cap,new},i,r} + Opex_{\text{fix},i,r} \cdot P_{\text{cap,exist},i,r} \right) + \sum_j \sum_t cost_{\text{fuel},j,r,t} \cdot E_{\text{fuel},j,r,t} \right) \quad (3)$$

The objective function drives decision variables towards minimal total system costs, which are composed of annualized investment costs, annual fixed and variable operating and maintenance costs, and fuel costs. The compiled optimization problem is solved by applying GUROBI barrier methods [42].

A formal mathematical description of *elesplan-m* is given in Appendix A.

3.3. Target regions and input parameters

For this study, *elesplan-m* is parametrized to represent the EU and all ENTSO-E member countries. These countries are partially aggregated to regions to reflect ENTSO-E grid structure and typical local country groups. The result is the 18-region model depicted in Figure 2. (Details of the region configuration are provided in Table C.10 in Appendix C). The transmission grid is aggregated to 31 representative inter-regional capacities. Its initial capacity is based on *Net Transfer Capacities* taken from Ref. [43]. The respective connections among the identified electricity supply regions are shown in Figure 2.

Specific demand and resource data, as well as existing power plant capacity, are available for each of the 18 regions. Total annual demand is assumed to increase constantly from 3252 TWh in 2016 to 4448 TWh in 2050 according to projections of Fürsch et al. [27]. Regional differences are reflected according to the overall demand, as well as to the shape of the load profile. Hourly load profiles are derived from Ref. [44] for each target region, based on an overall peak demand of 585.5 GW in 2016 and 760 GW in 2050.

Table 2: EU GHG emission reduction targets in % relative to 1990 levels and in absolute numbers in the power sector from now to 2050 in five-year steps [6].

Year	2016	2020	2025	2030	2035	2040	2045	2050
% to 1990	88.7	70.6	49.2	37.1	24.2	12.1	4	1.6
Mt CO_2eq	1306	1039	724	546	356	178	59	24

Time series of RES feed-in are obtained from detailed technological and meteorological models for wind and PV plants. Resource input data are based on highly resolved spatio-temporal meteorological data from the NASA SSE dataset, which covers the entire world in one degree by one degree spatial resolution and provides hourly values for every location over a 20-year time period (Surface Meteorology and Solar Energy SSE Release 6.0) [45]. To process these input data we applied a model of Huld et al. [46] for PV power feed-in and manufacturers power curves (Enercon E101 at 100 m hub height) for wind power feed-in. Afterwards, the 2/3 best sites covered by each region were averaged to derive one time series representing local characteristics for each region. Hydro power feed-in is determined from the aggregated output of existing European hydro plants. Generation data is provided on a monthly basis by the ENTSO-E [47] aggregated at country level. Validation with reference data from the Eurostat database [48] and from Ref. [49] for Switzerland shows good coverage of annual hydro generation.

The *elesplan-m* model considers initial existing power system capacity and the expected remaining lifetime. The Platts database provides power plant capacity data, including location, type and commissioning dates for conventional power plant technologies, so we used it as a primary source [50]. Capacity data for RES power plants are supplemented by data of *EurObserv'ER*, *The Windpower* and *British Petroleum* [51, 52, 53].

Further, we apply pan-European GHG emission targets and economic parameters. The following European Union (EU) emission targets depicted in Table 2 are used as constraints for the European power supply system (cf. Eq. 2).

We assumed no further expansion of nuclear power, hydro power and pumped hydro storage. The hydro power cap is reasonable because it is limited by geophysical conditions, though we do assume that all economically feasible hydro power potential has already been exploited. The constraint on nuclear power is based on the expectation that nuclear power will be phased out in Europe.

Efficiency parameters, capital expenditures (Capex) and fuel cost for components and technologies are listed in Table 3. For the observed period, costs of conventional power generation are increasing, whereas costs of RES-based power generation and storage technologies are falling.

Operational expenditures and lifetime are assumed to remain constant for all *decision years* and are given in Table 4. Additional parameters[2] are presented in the Appendix (cf. Appendix B).

We assume a weighted average cost of capital (WACC) of 6 % for mature technologies (coal, OCGT, CCGT, hydro power and pumped hydro storage) and 7 % for technologies associated with higher investment risks (wind, PV, nuclear, batteries, PtG, gas storage and transmission).

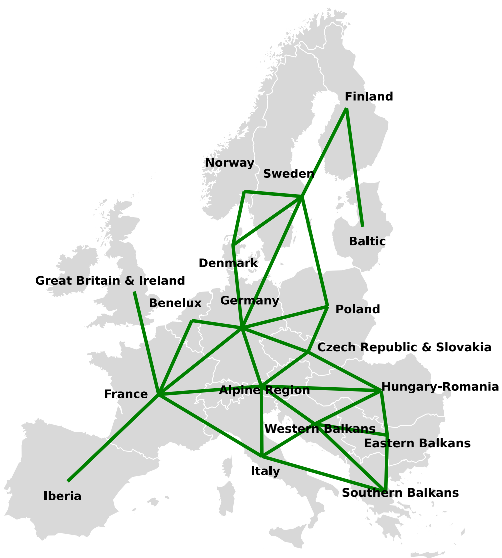

Figure 2: Map of the 18 target regions considered in *elesplan-m*. Green lines indicate aggregated inter-regional transmission capacity.

3.4. Sensitivity analysis

We tested the power sector transformation pathways resulting from our study for robustness in a sensitivity analysis. The cost assumptions for power system technologies are key drivers in the model, so we vary these in sensitivity scenarios (see Table 5). An additional sensitivity scenario in which transmission capacity expansion is varied is considered. In the *transmission expansion limit* scenario, we impose a cap on transmission capacity expansion up to twice the initial capacity per line *transmission expansion limit*.

Parameters not shown in Tab 5 remain constant in all scenarios.

4. Results – Decarbonization pathway

Our model calculations with *elesplan-m* result in one potential decarbonization pathway for the European power supply system until 2050 that covers all electricity demand expected in the next 35 years.

4.1. GHG emissions, RES share and LCOE

In our simulation, the transition of the European power supply system to meet EU mitigation targets results in an increased RES share and increased LCOE. The overall GHG emissions add up to 1,024 Mt CO_2eq in 2016 and fall to 24 Mt CO_2eq by 2050. During this same period, the European average RES share rises continuously from 27.5 % to 98.5 %. This is accompanied by a 35 % increase of LCOE from 6.7 ctEUR/kWh to 9 ctEUR/kWh (see Fig. 3).
The initial GHG emission limit of 1,306 Mt. CO_2eq in 2016 [6] is not fully exploited by this cost-optimal power system, as only 1,024 Mt CO_2eq are emitted. After a slight increase to 1,039 Mt. CO_2eq in 2020, GHG emissions fall until the year 2050 – a reduction of 98.4 % compared to 1990 GHG emission levels (see Fig. 3). The composition of GHG emissions changes during the simulation period. Initially, coal-based power generation has by far the highest share of GHG emissions. With stronger emission targets, more and more conventional generators are converted to gas-fired power plants with lower specific emission values. By 2050, only GHG emissions from burning natural gas can be observed.

4.2. Capacities and power generation shares

In 2016, fossil and nuclear power generation technologies represent more than 58 % of the 834 GW of installed capacity in Europe and contribute more than 72 % to the overall electrical energy production of 3,275 TWh. Both total installed capacity and total generation increase over time until they reach 2,896 GW and 5,968 TWh respectively in 2050. During this period, RES share of installed capacity and generation increase dramatically (see Figures 4 and 5).

[2] lifetime, operational expenditures, efficiencies and energy-to-power ratios for storage technologies; capital expenditures, operational expenditures and transmission efficiency of grid; fuel emission factors

Table 3: Capex of power generation technologies presented in EUR/kW, fuel cost in EUR/MWh$_{th}$ and efficiency parameters in %. Costs of storage technologies are specific to their energy capacity and are measured in EUR/kWh. Values of power generation technologies and pumped hydro storage are taken from Ref. [54] except for those for PV, which are taken from Ref. [55]. Battery costs are based on projections for zinc-bromide and molten salt technology and are provided by Ref. [56]. Capex for power-to-gas includes electrolysis, H_2 storage and methanation unit [57]

Technology	Parameter	2016	2020	2025	2030	2035	2040	2045	2050
Wind	Capex	1381	1349	1316	1286	1256	1226	1198	1170
PV	Capex	1300	1000	900	800	780	760	740	730
Hydro power	Capex	3263	3263	3263	3263	3263	3263	3263	3263
	Capex	6528	6528	6528	6528	6528	6528	6528	6528
Nuclear	Fuel	2.3	2.7	3.1	3.9	4.7	5.5	6.7	7.8
	Efficiency	33.2	33.3	33.5	33.7	33.8	34	34.2	34.3
	Capex	1523	1523	1523	1523	1523	1523	1523	1523
Coal	Fuel	6.25	7.05	7.05	7.25	7.65	8	8.4	8.8
	Efficiency	44.75	45.05	45.3	45.55	45.85	46.1	46.35	46.65
CCGT	Capex	870	870	870	870	870	870	870	870
	Efficiency	60.2	60.5	60.7	61	61.2	61.5	61.7	61.9
	Capex	435	435	435	435	435	435	435	435
OCGT	Fuel	24.3	27.0	27.8	28.6	28.2	28.2	27.8	27.4
	Efficiency	39.1	39.2	39.2	39.3	39.4	39.5	39.5	39.6
Pumped hydro storage	Capex	272	272	272	272	272	272	272	272
Batteries	Capex	1192	580	359	319	289	289	289	289
Power-to-gas	Capex	1565	1356	1025	782	703	600	534	522

Table 4: Expected lifetimes and opex$_{fix}$ for power generation technologies taken from Refs. [54, 58, 55, 59]. Both parameters are provided as static numbers that do not change over the investigated time horizon. Fixed annual operational expenditures opex$_{fix}$ are presented relative to the capital expenditures. Assumptions for PtG technology are taken from Ref. [17], except for the efficiency of 55 %, which is provided by Ref. [40].

Technology	Lifetime in a	opex$_{fix}$ in %
Wind	25	3.3
PV	25	1.6
CCGT	30	2.5
OCGT	30	3
Nuclear	40	2
Coal	40	2
Hydro power	100	2
Pumped hydro storage	60	1
Power-to-gas	25	4

Table 5: Capital expenditures Capex varied in sensitivity analysis: *progressive* (stronger cost reduction of RES technologies), *conservative* (reduced cost reduction of *RES* technologies) and *storage conservative* (reduced cost reduction of storage technologies). Fixed operating expenditure Opex$_{fix}$ is adapted accordingly by applying the same percentage value as in the base scenario (Wind 3.3 %, PV 1.6%, PtG 4 % except for batteries that have constant Opex$_{fix}$ of 1 EUR/kW).

Technology	2016	2020	2025	2030	2035	2040	2045	2050
				Progressive				
Wind	1381	1329	1171	1145	1118	1091	1066	1041
PV	1300	840	686	533	502	471	440	425
				Conservative				
Wind	1381	1381	1381	1376	1344	1312	1282	1252
PV	1300	1163	1117	1072	1063	1053	1044	1040
				Storage conservative				
Power-to-Gas	1565	1408	1160	977	918	841	791	782
Battery storages	1192	788	643	616	596	596	596	596

Coal-fired power generation is phased out after 2035, while nuclear is phased out five years later. The nuclear power phase out follows from the assumption that no additional capacity extensions are allowed and therefore all nuclear power plants will have been retired by 2040 in accordance with their expected lifetimes. Coal-fired power generation phase-out is driven by the GHG reduction targets. Even though coal power plant capacity of 109 GW exists until 2050, this is not used. Full-load hours for coal power plants constantly decrease to nearly zero (from 2040, see Table 6).

Declining dispatchable capacity of nuclear and coal-

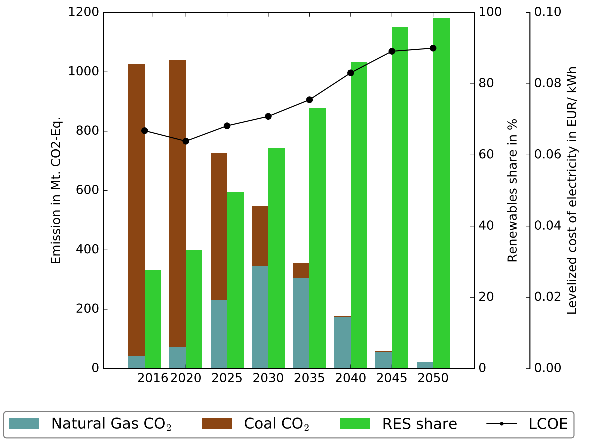

Figure 3: Total GHG emissions (brown and gray bars (stacked)), average RES share (green) and average LCOE (black line) of Europe's power supply system

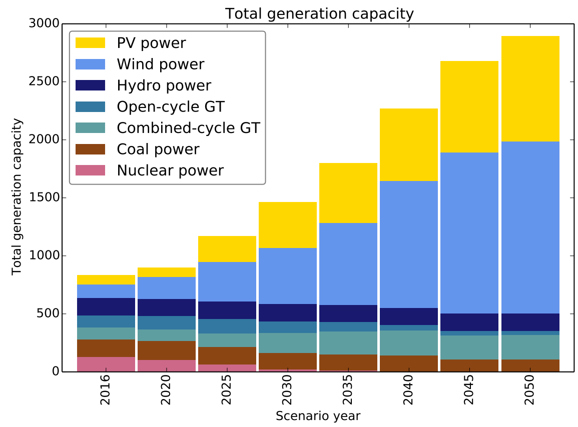

Figure 4: Total installed capacity by power generation technology in each *decision year*

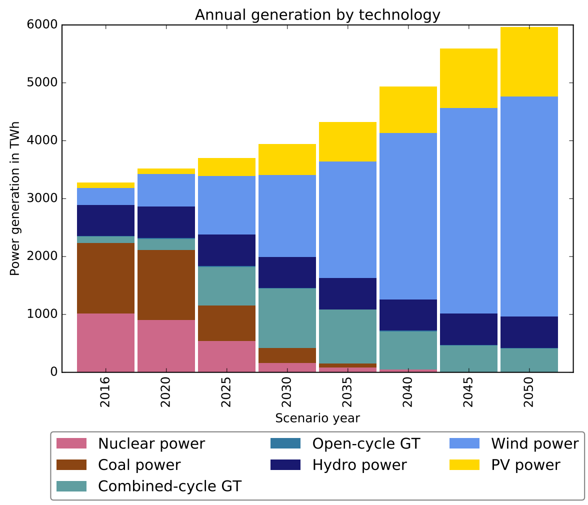

Figure 5: Power generation by technology in each *decision year*

Table 6: Full-load hours of coal-fired power plants over the observed period of time

Year	2016	2020	2025	2030	2035	2040	2045	2050
Full-load hours	7981	7458	4043	1740	463	46	30	19

fired power plants is partially compensated by gas-fired power plants. This drives increases in capacity and generation of combined-cycle gas power plants. Beginning in the year 2035, an increasing share of power generation is based on synthetic natural gas (SNG) which is burned in either OCGT or CCGT plants.

RES technologies gradually gain importance during the simulated time frame. Wind power capacity increases 1,158 % (from 118 GW in 2016 to 1,485 GW in 2050); this corresponds to an average annual expansion rate of 40.2 GW/a. Photovoltaic power generation capacity's average annual expansion rate is 24.4 GW/a, increasing 1,004 % (from 79.7 GW in 2016 to 909 GW in 2050). The sharp increase in renewable power generation means the RES share is greater than 50 % from the year 2030 and reaches almost 100 % in 2050. In 2050, wind power constitutes the largest share of the power supply with 3,805 TWh (63.7 %), while PV power supplies 1,199 TWh (20.1 %). In our simulation, hydro power remains constant – due to the constraint on capacity expansion – with 148.5 GW installed capacity and 538.5 TWh power generation. Its overall share of power generation decreases from 16.6 % to 9 % due to the increased demand.

4.3. Flexibility technologies and energy storage capacity

While total power generation capacity continuously increases during the simulated time period, dispatchable capacity (gas and coal power plants, batteries and PHS) decreases until the year 2050 (to 400 GW) (cf. Figure 4 and Fig 6). Gas-fired power plant technologies' share of dispatchable capacity increases constantly. From 2030 to 2050 a large expansion of gas power plant capacity occurs.

The energy storage technologies – batteries and pumped hydro storage – provide dispatchable capacity as well. Pumped hydro storage provides 43 GW of storage power, which remains constant due to the assumption that PHS capacity will not be expanded. Batteries are introduced in 2045, providing 22.2 GW storage power in 2050. Energy storage technologies provide both positive and negative capacity. Total input power to energy storage is 432 GW in 2050 (367 GW PtG, 43.2 GW pumped hydro storage and 22.2 GW batteries). Power-to-gas is introduced before battery storage systems: In 2035, 23 GW of (electrical) PtG input is required to operate the European power system in a techno-economically optimized way.

The share of generation that is not used to meet immediate demand increases from 22.8 TWh to 1163 TWh in the simulated time period. In 2050, 19.5 % of generated electricity is curtailed or irrecoverably lost due to efficiency losses within storage or transmission systems. Curtailed electricity accounts for 30.2 % of unused power generation, efficiency losses related to PtG processes represent 61.6 % and the remaining share of 8.2 % results from efficiency losses in transmission, pumped hydro storage and battery systems.

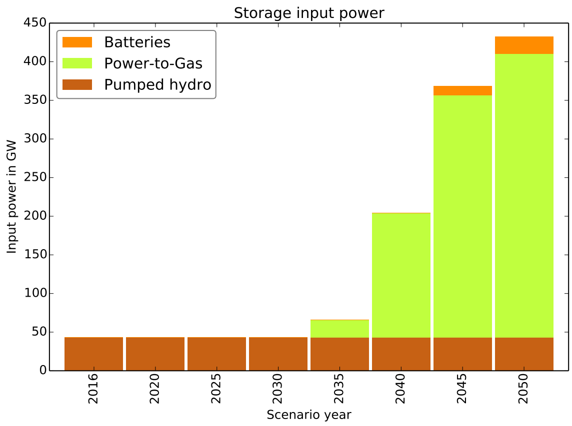

Figure 6: Input power of energy storage technologies in *elesplan-m*. Pumped hydro storage and batteries have the same input and output power whereas power-to-gas input power is independent of gas storage and re-electrification by gas power plant technologies.

4.4. Regional distribution and transmission

We also analyzed inter-regional transmission capacity with *elesplan-m*. Figure 2 shows all 31 connections among the 18 target regions. In 2016, 79.5 GW of transmission capacity exist (of which 12.2 GW are newly built), which are expanded to 362 GW by 2050. The largest increase can be observed for the connection between Denmark and Germany with 20 GW (+336 %), and between Great Britain and France, also with 20 GW (+344 %). In relative terms, the greatest transmission expansion occurs between the Western and Southern Balkans. Here the initial transmission capacity of 0.2 GW in 2016 increases to 9.1 GW in 2050 (+4460 %). The next largest transmission capacity expansion in relative terms is between Germany and Sweden (0.61 GW in 2016 to 8.3 GW in 2050, or +1256 %). In contrast to the general trend of transmission capacity expansion, a decrease between the Western Balkans and Hungary-Romania (1.2 GW to 0.94 GW, -21.6 %) and Western and Eastern Balkans (1.35 GW to 0.56 GW, -58.2 %) is observed.

Looking at the electricity exchange, the annual net energy transmission increases from 188.4 TWh (2016) to 976.7 TWh (2050). Figure 7 illustrates the direction and amount of power exchange among the interconnected regions for the year 2050. In 2050, the largest annual net exchange is between Denmark and Germany. Denmark is the largest net exporting region in 2050 with total annual net export of 212.2 TWh. Second largest net exporter of electricity is the Southern Balkans (92.5 TWh) followed by France (88.1 TWh), while the largest net importing regions are Sweden (122.7 TWh), Germany (89.6 TWh) and Italy (83.1 TWh). All regions which serve as power hub are located in central Europe (Germany, Alpine countries, Czech Republic & Slovakia) with the exception of Sweden. These regions redistribute power from major suppliers – Denmark and France, for example – to Southern and Eastern European countries.

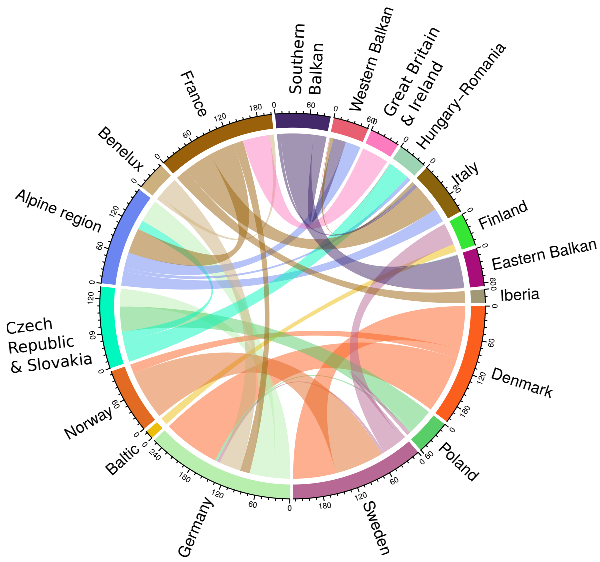

Figure 7: Net power exchange in TWh among the 18 target regions in 2050.

4.5. *Investment needs and cost*

The total investment in the European power supply system needed to meet the EU GHG mitigation targets is 403 billion EUR until 2050 (cf. Figure 8). This number includes both new investment and investment in existing plant refurbishment. The average annual investment is 11.85 billion EUR, but investments are not evenly distributed over the full 34-year period. They increase until the period 2036 to 2040, when annual investments peak at 17.1 billion EUR, declining slightly in the following two periods.

All investment periods beyond the year 2016 are dominated by expenditures for wind and PV power plants. Beginning with the period 2031 to 2035, investments in flexibility increase, these being distributed between PtG and battery systems and flexible plants such as OCGT and CCGT. Overall, investments in wind power represent the largest share, requiring average annual investments of 9.88 billion EUR/a (335.8 billion EUR in total). Photovoltaic power needs nearly constant investment over the entire period. Compared to power generation and storage capacity, investments in transmission capacity represent only a negligible share of expenditures.

Annualized investment costs combined with operation and maintenance and fuel costs result in the LCOE, which is calculated for each *decision year*. The composition of LCOE changes over time (cf. Figure 9). At the outset, the major part of LCOE is related to nuclear and fossil-based power generation. Nuclear power plants have high specific power generation costs due to very high related CAPEX. They are gradually substituted with fossil and RES power plants, depending upon the GHG emission limits. The LCOE of coal and gas power plants are dominated by fuel expenditures. Wind and PV power account for higher shares of LCOE as the system evolves. The impact of fuel cost on the LCOE decreases and expenses in annuities of RES power generation capacity gain importance. Transmission and storage capacity make up only a small share of LCOE based on the related CAPEX and OPEX.

4.6. *Sensitivity analysis*

Figure 10 shows levelized cost of electricity (LCOE) over the full period for each of the scenarios in the sensitivity analysis. The scenario *progressive*, which assumes lower costs for major RES technologies, results in lower overall LCOE. The other three scenarios result in increased costs. The scenarios *conservative* and *storage conservative* result in higher LCOE. The scenario including a cap on transmission capacity expansion (*transmission expansion limit*) drives the system

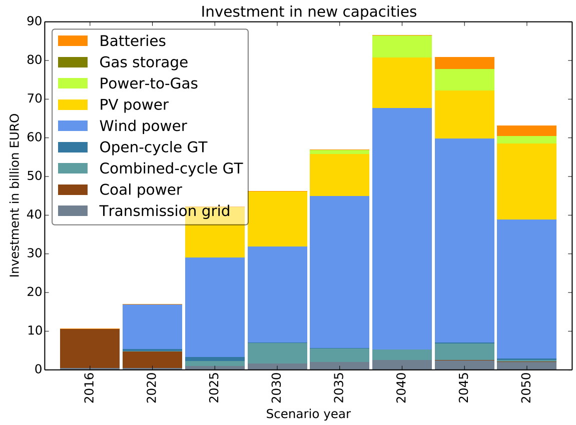

Figure 8: Accumulated investment needs shown for each *decision year*. 2016 (one year of investments), 2020 (four years of investments), 2025 and higher (five years of investments).

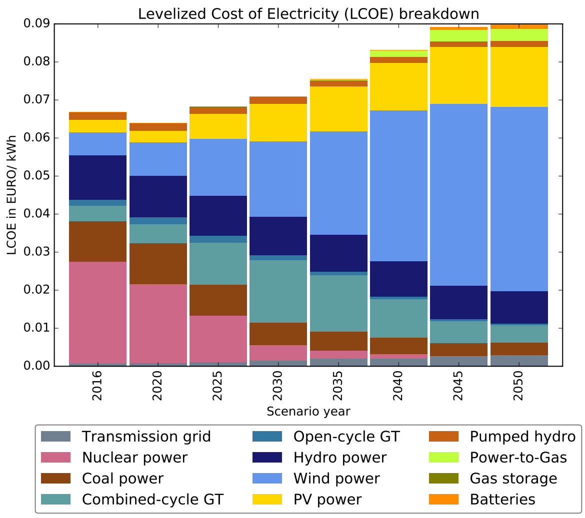

Figure 9: Cost break-down of European average LCOE for each *decision year*

towards solutions based on reduced power exchange which is accompanied by higher LCOE.

5. Discussion

Our results have certain particularities. One of them is that GHG emission limits are not fully exploited in 2016. In this *decision year*, calculated emissions of 1,024 Mt CO_2eq are well below the exogenous emissions limit of 1,306 Mt CO_2eq. This can be partially explained by more power generation from nuclear power

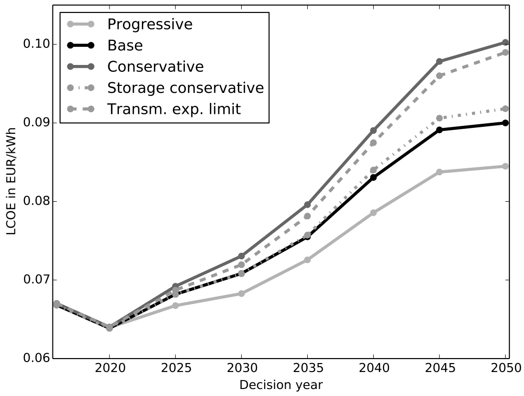

Figure 10: LCOE of sensitivity scenarios.

plants and less coal-based power generation compared to real numbers from 2014 and to the derived anticipations for 2016 [53]. In addition, RES capacity increases for wind and PV have been faster than expected and therefore the GHG emission targets for 2016 may be considered weak. We recommend that policy makers implement dynamic mitigation targets which can be adapted for the single *decision years* according to previous values.

Beginning in 2020, GHG output allowed under the mitigation targets is fully exploited. Lower LCOE in 2020 (as compared to 2016) results from decommissioning of nuclear plants, which have high annualized costs. They are partly substituted by coal plants, which increase GHG emissions until the given limit, and partly by wind and PV power plants.

Our cost-optimal phase-out of coal-fired power generation under the constraint of GHG reduction targets to the year 2040 raises a subsequent issue: until 2040, utilization rates of coal-based power generation significantly decrease. Average full load hours of 1740 h/a (in 2030) or even 460 h/a (in 2035) do not provide a viable business case to coal power plant operators, who would struggle to recover their investments. Given this, current long-term investments into coal power plants merit reconsideration, as it seems unlikely they will be allowed to operate long enough to pay them back.

The spatial distribution of resources influences the share of RES in the different regions. According to our model results, the cost-optimal decarbonization pathway for Europe depends on exploiting high-potential RES sites. For example, Great Britain and Denmark provide large amounts of electricity to other regions based on very cost-competitive wind power generation due to excellent wind resources in both countries. In the case of Great Britain, this is limited only by the annual transmission capacity expansion cap of 500 MW per cross-region link. Here, it is important to keep in mind that our results are based on a Europe-wide cost-optimal power system design that does not respect the individual interests of single countries. Considering countries' individual interests, which might manifest themselves in limits such as a limit on the maximum amount of annual net imported electricity, would probably result in higher overall costs and different distributions of power generation sites and transmission capacities, as our sensitivity scenario *transmission expansion limit* suggests.

Finally, we found that PHS at current capacity levels is sufficient to achieve large-scale fluctuating RES integration up to 70 % coverage of demand. Afterwards, additional storage capacity is required. We identified PtG as the techno-economically most viable technology. Batteries are competitive beginning in 2045. The main advantage of PtG-based energy storage compared to batteries is the decoupling of input power, storage capacity and output power. Despite this, batteries may prove competitive decades earlier than revealed by our modeling results, provided they are used for grid stability and balancing services. Such services, which we did not simulate, can be provided by batteries (see Resch et al. [60]). Our chosen temporal resolution, with 1 h increments and the aggregated simulation of power generation and transmission capacity, does not allow us to study the impact of storage systems on grid stability, frequency and voltage levels.

Even with higher storage costs as in the *storage conservative* sensitivity scenario the capacities – especially of PtG – remain very high. This underlines the need for a flexible medium and long-term energy storage system to integrate large amounts RES-based generation.

Our model *elesplan-m* is not without limitations, of course. The representation of the transmission grid is highly simplified. Aggregated inter-region transmission capacity does not account for real length and endpoints in the countries. Moreover, the whole national grid and underlying lower voltage level grids are not reflected in this model. This may cause the model to underestimate costs related to the investments in grid capacity associated with the decarbonization of Europe's electrical power system. The chosen temporal resolution of one-hour increments accounts for some characteristics of power generation based on fluctuating RES, but some important aspects cannot be described. Our results do not resolve power system behavior at finer temporal scales (e.g. voltage and frequency issues). In addition, technological and economic input parameters are aggregated for all regions and could be further refined in follow-up studies.

Despite these limitations, our results are similar to those from comparable studies. Haller et al. found a comparable cost-optimal generation mix for the year 2050 to achieve GHG reduction of -90 % at similar LCOE. As they considered North African countries linked to the European transmission system, more solar power generation is suggested than in our simulations. Nevertheless, regions with excellent wind resources are identified as major net exporting regions as well [24]. Our contribution is to precisely show the potential of PtG in a power supply system based on large shares of fluctuating RES.

The results published by Fürsch et al. are comparable to our findings for the period between the *decision years* 2035 and 2040 with respect to reduction targets and RES shares [27]. Their power system for 2050 is comprised of significant shares of coal, nuclear and gas-based power generation. Photovoltaic power generation plays a minor role but concentrated solar power (CSP) a larger one. In comparison, our results show longer operating times for gas power plants. This is due both to their dual function as a reconversion unit of synthetic natural gas from PtG to electricity and the low specific GHG emissions for natural gas.

6. Conclusions

Our research work was driven by two main questions: How can the decarbonization pathway of Europe's power supply system be modeled, and what is the techno-economically optimized transition pathway for meeting EU GHG emission targets until 2050? We found answers to both questions.

First, a review of power system models showed that different options exist to simulate decarbonization pathways. As none of the presented options could meet all the requirements for our study, we applied our own tool *elesplan-m*. This tool includes all major power generation and storage technologies as well as transmission capacity to reflect inter-regional power exchange. Due to its flexible spatial resolution it was possible to integrate 18 single European regions within the multi-region framework of *elesplan-m*. The *elesplan-m* software enables short-term (hourly increments) and long-term (investment period of 34 years) modeling and analyses, which was one of our stated requirements. Additionally, GHG emission constraints can be set within *elesplan-m* which is essential for simulating decarbonization pathways.

Finding *elesplan-m* suitable for our modeling task, we applied it to identify the least-cost decarbonization pathway. The results suggest that EU's reduction targets could be achieved by investing 403 billion EUR until 2050. This would lead to an energy supply system which is mainly dominated by wind power (1,485 GW) and PV (909 GW) which are supported by 150 GW hydro power and 244 GW gas power capacity. In addition, 432 GW of storage and 362 GW of transmission capacity are required to temporally and spatially distribute electricity. While the overall GHG emissions decrease from 1,024 to 24 Mt CO_2eq per year, the LCOE increases from 6.7 to 9 ctEUR/kWh.

Our analysis revealed a techno-economically optimized decarbonization pathway along eight *decision years*. This allows all involved public and private-sector stakeholders to imagine not only the final configuration of a decarbonized energy supply system for Europe, but also to influence and understand the steps necessary to achieve it in a cost-efficient manner.

7. Acknowledgments

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Nomenclature

Indices

i	power plant, energy storage, transmission grid technologies
j	fuels
l	transmission lines
r	regions
t	time steps

Decision variables

[3] *oemof* is an open source energy system modelling framework. For more details, see `https://oemof.wordpress.com/`. Collaboration is welcome on `https://github.com/oemof/oemof`

$E_{\text{curtail},r,t}$	Curtailment
$E_{\text{demand},r,t}$	electricity demand
$E^{\text{elec}}_{\text{gen},i,r,t}$	Power generation
$E^{i}_{\text{fos. gas},r,t}$	gas flow of natural gas
$E_{\text{fos. gas},r,t}$	total fossil gas consumption
$E_{\text{fuel},j,r,t}$	Fuel consumption
$E^{\text{discharge}}_{\text{storage,gas},r,t}$	gas storage discharge
$E^{\text{charge}}_{\text{storage,gas},r,t}$	gas storage charge
$E^{\text{volatile}}_{\text{gen},i,r,t}$	Power generation of RES
$E^{\text{syn. gas}}_{\text{gen, PtG},r,t}$	SNG production
$E^{in}_{\text{PtG},r,t}$	electrical power PtG (input)
$E^{i}_{\text{syn. gas},r,t}$	gas flow of SNG
$E^{\text{discharge}}_{\text{storage},i,r,t}$	storage discharge
$E^{\text{charge}}_{\text{storage},i,r,t}$	storage charge
$E_{\text{trans},r,t}$	transmission balance
$E_{\text{trans,in},l,t}$	incoming transmission power
$E_{\text{trans,out},l,t}$	outgoing transmission power
$P_{\text{cap,new},i,r}$	Name plate capacity (new)
$P_{\text{inst, PtG},r,t}$	Name plate capacity PtG
$P^{\text{cap}}_{\text{storage},i,r}$	capacity of storage
$P_{\text{inst, trans},l}$	Capacity transmission line
$SoC_{\text{storage},i,r,t}$	state of charge

Parameters

$Capex_{i,r}$	Capital expenditures
CRF_i	Capital recovery factory
$cost_{\text{fuel},j,r,t}$	fuel cost
$E/P^{\text{in}}_{\text{storage}}$	energy to power ratio (charge)
$E/P^{\text{out}}_{\text{storage},i}$	energy to power ratio (discharge)
η_i	efficiency of power plant
$\eta^{\text{out}}_{\text{storage},i}$	discharge efficiency
$\eta^{\text{in}}_{\text{storage},i}$	charge efficiency
η_l	transmission efficiency
$k_{\text{feedin},i,r,t}$	normalized power generation
n	lifetime
$Opex_{\text{fix},i,r}$	Fix operational expenditures
$Opex_{\text{var},j,r}$	Variable operational expenditures
$P_{\text{cap,exist},i,r}$	Name plate capacity (existing)
z	interest rate
σ_i	GHG emissions 1 kW capacity
ρ_i	GHG emissions 1 kWh generation
Υ	annual allowed GHG emissions

Acronyms

SEE South-East Europe
EU European Union
GHG greenhouse gas
RES renewable energy sources
elesplan-m *European long-term electricity system planning model*
PV photovoltaic
ENTSO-E European Network of Transmission System Operators for Electricity
crf capital recovery factor
CCGT combined cycle gas turbine
OCGT open cycle gas turbine
SNG synthetic natural gas
PtG Power-to-Gas
SoC state of charge
Capex capital expenditures
Opex$_{fix}$ operational expenditures
LCOE levelized cost of electricity
WACC weighted average cost of capital
CCS carbon capture and storage
PHS pumped hydro storage

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Appendix A. Model equations

Appendix A.1. RES power generation

RES based power generation modeling is based on predefined normalized time-series of feed-in, the preparation of which is described in section 3.3. Parameter $k_{\text{feed-in},i,r,t}$ of equation A.1 reflect hourly normalized power feed-in.

$$E^{\text{volatile}}_{\text{gen},i,r,t} = k_{\text{feed-in},i,r,t} \cdot \left(P_{\text{cap,exist},i,r} + P_{\text{cap,new},i,r}\right) \quad \text{(A.1)}$$

Appendix A.2. Thermal power plants

Power generation of a dispatchable power plant technology is constrained by its nameplate capacity. This capacity is composed of two terms: the current existing power plant capacity $P_{\text{cap,exist},i,r}$ plus the capacity of its expansion $P_{\text{cap,new},i,r}$ (refer equation A.2).

$$E^{\text{elec}}_{\text{gen},i,r,t} \leq \left(P_{\text{cap,exist},i,r} + P_{\text{cap,new},i,r}\right) \quad \text{(A.2)}$$

Coal and gas power plants are modeled slightly differently with respect to fuel consumption. Coal power plants fuel consumption is described by Equation A.3.

$$E^{\text{elec}}_{\text{gen},i,r,t} = \eta_i \cdot E_{\text{fuel},j,r,t} \quad \text{(A.3)}$$

Two gas power plant technologies represented in *European long-term electricity system planning model* (*elesplan-m*) (combined cycle gas turbine (CCGT) and open cycle gas turbine (OCGT)) are modeled analogously, differing only in their efficiency and cost parameters. The natural gas and SNG feeding the gas power plants is differentiated in order to assess shares of fossil- and RES-based power generation. As shown in equation A.4 gas power plants are modeled with a static efficiency.

$$E^{\text{elec}}_{\text{gen},i,r,t} = \eta_i \cdot \left(E^{i}_{\text{syn. gas},r,t} + E^{i}_{\text{fos. gas},r,t}\right) \quad \text{(A.4)}$$

Appendix A.3. Energy storage technologies

Energy storage technologies in *elesplan-m* are modeled using generic energy storage constraints. This is applied to battery-electric storage, pumped hydro storage and to gas storage as part of the PtG unit (see section Appendix A.4). A specific type of model for both types of storage technology is generated by applying a specific parameter set to the generic energy storage model. The energy storage model considers state of charge (SoC) conservation, charge and discharge efficiency.

$$SoC_{\text{storage},i,r,t} = SoC_{\text{storage},i,r,t-1} - \frac{E^{\text{discharge}}_{\text{storage},i,r,t}}{\eta^{\text{out}}_{\text{storage},i}} + E^{\text{charge}}_{\text{storage},i,r,t} \cdot \eta^{\text{in}}_{\text{storage},i} \quad \text{(A.5)}$$

Equation A.5 describes SoC conservation in energy storage under consideration of storage charge and discharge processes. Based on the SoC of the last time-step $SoC_{\text{storage},i,r,t-1}$ the current SoC is calculated according to the charge or discharge efficiency.

To obtain consistent results from a model run, a suitable start value for $SoC_{\text{storage},i,r,t=1}$ has to be defined. This is achieved by setting $SoC_{\text{storage},i,r,t=1}$ equal to the SoC of the last time step. Equation A.6 is derived from equation A.5 and only applied on the first time step of a model run. It sets the initial SoC to the value of the last time step of the model run respecting charge and discharge of storage.

$$SoC_{\text{storage},i,r,t=1} = SoC_{\text{storage},i,r,t=8760} - \frac{E^{\text{discharge}}_{\text{storage},i,r,t=1}}{\eta^{\text{out}}_{\text{storage},i}} + E^{\text{charge}}_{\text{storage},i,r,t=1} \cdot \eta^{\text{in}}_{\text{storage},i} \quad \text{(A.6)}$$

The parameter $E/P^{\text{in, out}}_{\text{storage}}$ represents the ratio of the amount of energy that can be stored to the maximum input/output power of the energy storage. Discharge $E^{\text{discharge}}_{\text{storage},i,r,t}$ is bounded by the output power (energy storage's capacity $P^{\text{cap}}_{\text{storage},i,r}$ divided by $E/P^{\text{out}}_{\text{storage},i}$) as shown in Equation A.7.

$$E^{\text{discharge}}_{\text{storage},i,r,t} \leq \frac{P^{\text{cap}}_{\text{storage},i,r}}{E/P^{\text{out}}_{\text{storage},i}} \quad \text{(A.7)}$$

Storage discharge is further limited by the energy currently in storage. Equation A.8 reflects this relationship under consideration of discharge efficiency $\eta^{\text{out}}_{\text{storage},i}$.

$$E^{\text{discharge}}_{\text{storage},i,r,t} \leq SoC_{\text{storage},i,r,t} \cdot \eta^{\text{out}}_{\text{storage},i} \quad \text{(A.8)}$$

Analogously to discharge (see Eq. A.7) the charging power is constrained as described in Equation A.9.

$$E^{\text{charge}}_{\text{storage},i,r,t} \leq \frac{P^{cap}_{\text{storage},i,r}}{E/P^{\text{in}}_{\text{storage}}} \quad \text{(A.9)}$$

Equation A.10 constraints the current charging level $SoC_{\text{storage},i,r,t}$ to the energy storage capacity $P^{\text{cap}}_{\text{storage},i,r}$. This prevents the model from overcharging energy storage.

$$SoC_{\text{storage},i,r,t} \leq P^{\text{cap}}_{\text{storage},i,r} \tag{A.10}$$

Appendix A.4. Power-to-Gas

In *elesplan-m*, PtG technology is assumed to serve as long-term energy storage (days to months). Power-to-gas comprises electrolysis and methanation to convert electricity to SNG and gas storage to retain produced gas. It is described in detail by Götz et al. [40]. This paper reduces the representation to an electricity-to-gas converter (covering both processes) and gas storage. Both gas power plant technologies are applied for re-electrification of produced SNG.

The PtG converter is modeled as a thermal power plant. Equation A.11 describes conversion efficiency of electricity to SNG conversion.

$$E^{\text{syn. gas}}_{\text{gen, PtG},r,t} = \eta_{PtG} \cdot E^{\text{in}}_{\text{PtG},r,t} \tag{A.11}$$

Equation A.12 describes maximum SNG production capacity, which is limited by the nominal capacity of the PtG converter.

$$E^{\text{syn. gas},r,t}_{\text{gen, PtG}} \leq P_{\text{inst, PtG},r} \tag{A.12}$$

The model *elesplan-m* uses an internal gas bus to balance SNG production, storage and conversion in the gas power plants. This bus is represented by equation A.13. The left-hand side describes feed-in to the bus, the right-hand side the consumers of SNG.

$$E^{\text{syn. gas}}_{\text{gen, PtG},r,t} + E^{\text{discharge}}_{\text{storage,gas},r,t} = E^{\text{OCGT}}_{\text{syn. gas},r,t} + E^{\text{CCGT}}_{\text{syn. gas},r,t} + E^{\text{charge}}_{\text{storage, gas},r,t} \tag{A.13}$$

The gas power plants are able to convert natural gas as well as SNG. Equation A.14 describes how both types of gas flows are represented in *elesplan-m*.

$$E_{\text{fos. gas},r,t} = E^{\text{OCGT}}_{\text{fos. gas},r,t} + E^{\text{CCGT}}_{\text{fos. gas},r,t} \tag{A.14}$$

Appendix A.5. Transmission system

Transmission of power between regions in *elesplan-m* is modeled by a coarse representation of European international electricity trading capacity. Single transmission lines connecting regions or countries are aggregated to representative transmission capacity between two regions. Equation A.15 applies Kirchhoff's current law to ensure flow conservation at each node.

Table B.7: Parameters electrochemical energy storage technologies taken from Ref. [56]. Parameters for gas storage are obtained from Refs. [61, 40]. Lifetime and opex$_{fix}$ is based on our own estimates.

Parameter	Battery	Gas storage	PHS	Unit
Lifetime	10	50	60	a
$Opex_{\text{fix}}$	1	2	2.5	EUR/ kWh$_{Cap}$
Efficiency η_{in}	89.44	100	86.6	%
Efficiency η_{out}	89.44	100	86.6	%
Max. discharge/charge	6	1	8	h

$$E_{\text{trans},r,t} = \sum_{l} \left(\eta_l \cdot E_{\text{trans,out},l,t} - E_{\text{trans,in},l,t}\right) \tag{A.15}$$

Transmission losses are accounted for in equation A.15, which includes transmission efficiency η_l. Equation A.16 guarantees that flow on transmission lines does not exceed nominal capacity.

$$E_{\text{trans,out},l,t} - E_{\text{trans,in},l,t} \leq P_{\text{inst, trans},l} \tag{A.16}$$

Investment models including the transmission grid tend to exploit regions with high energy potential and therefore dramatically extend transmission capacity. This does not reflect lessons learned from the recent decades of transmission grid planning in Europe. To limit annual transmission grid expansion rates to reasonable levels, a further constraint is introduced (refer Equation A.17).

$$P_{\text{inst. new, trans},l} \leq \rho_{\text{trans. exp. cap}} \tag{A.17}$$

Appendix A.6. Misc

Capital recovery factor CRF_i is applied to determine annuities of investments based on interest rate z and lifetime n.

$$CRF_i = \frac{z \cdot (1+z)^n}{(1+z)^n - 1} \tag{A.18}$$

Appendix B. input data

Table B.8: Parameters of transmission system. All presented parameters from Ref. [55]

Parameter	Value	Unit
NTC expansion cost (Capex)	882	EUR/ (kW · km)
O & M cost ($Opex_{\text{fix}}$)	0.6	% of investment
Losses	1.6	% of power flow

Appendix C. List of countries

Table B.9: GHG emission factors for different fuels.

Fuel	Emission factor in kg/kWh$_{th}$	Source
Coal	0.361	[62]
Natural gas	0.204	[62]
Uranium	0	[63]

Table C.10: Countries represented by defined regions that are used in *elesplan-m*

Region name	Countries
Alpine region	Austria, Switzerland, Liechtenstein
Baltic	Estonia, Latvia, Lithuania
Benelux	Belgium, Luxembourg, Netherlands
Czech republic & Slovakia	Czech republic, Slovakia
Denmark	Denmark
Eastern Balkans	Bulgaria, Kosovo, Serbia
Finland	Finland
France	France, Monaco
Germany	Germany
Great Britain & Ireland	Great Britain, Ireland
Hungary-Romania	Hungary, Romania
Iberia	Andorra, Portugal, Spain
Italy	Italy, San Marino, Vatican state
Poland	Poland
Norway	Norway
Southern Balkans	Albania, Greece, Macedonia
Sweden	Sweden
Western Balkans	Bosnia & Herzegovina, Croatia, Montenegro, Slovenia