ENERDAY 2023

17th Conference on Energy Economics and Technology

"The energy crisis as an accelerator of a sustainable transformation"

Book of Abstracts

5th May 2023
Dresden

Organising institutions

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Sponsors

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50Hertz operates the electricity transmission system in the north and east of Germany, which it expands as needed for the energy transition. Our extra high voltage grid has an electrical circuit length of more than 10,000 kilometres, or the distance between Berlin and Rio de Janeiro. The 50Hertz control area covers Brandenburg, Mecklenburg-Western Pomerania, Saxony, Saxony-Anhalt, and Thuringia, as well as the city states of Berlin and Hamburg. Within these regions, 50Hertz and its around 1,400 employees ensure that 18 million people are supplied with electricity around the clock. 50Hertz is a forerunner in the field of secure in- tegration of renewable energy. In our grid area, we want to integrate 100 percent renewable energies se- curely into the grid and system by 2032 - calculated over the year. The shareholders of 50Hertz are the Bel- gian holding Elia Group (80 percent), which is listed on the stock exchange, and the KfW bank group with 20 percent. As a European TSO, 50Hertz is a member of the European Network of Transmission System Operators for Electricity (ENTSO-E).

GESELLSCHAFT für ENERGIEWISSENSCHAFT und ENERGIEPOLITIK E.V. GEE WWW.GEE.DE

The GEE - Society for Energy Science and Energy Policy (Gesellschaft für Energiewissenschaft und Energiepolitik, abbr. GEE) offers a politically open and interdisciplinary forum for an active exchange and discussion of ideas within the field of energy. It therefore brings together experts from the field of energy economics, politics, professional associations and unions as well as scholars and researchers. The GEE was founded in 1981 and is the German Chapter of the International Association of Energy Economics (IAEE). With its 200 members today, the GEE promotes energy topics in form of seminars, webinars, Ph.D. workshops and conferences. Moreover, the GEE awards annually the "GEE Preis des Energieforums Berlin" to the best thesis in the categories master and Ph.D. level.

enerCONNECT
Verein zur Förderung wissenschaftlicher Arbeiten in der Energiewirtschaft an der TU Dresden e.V.

The non-profit association enerCONNECT e.V. was founded in 2014 to promote scientific work in energy economics at the TU Dresden. At the same time, the association is intended to facilitate an exchange beyond the scope of studies and thus supports a network of experts in the field of energy economics. It promotes energy topics in the form of awards, seminars, regular tables, etc. By doing so, enerCONNECT also acts as an association of alumni. Today the association has around 46 members. enerCONNECT is thus aimed at all students, graduates, interested parties and friends of the Chair of Energy Economics.

In cooperation with the GEE, enerCONNECT has always awarded the "Best Scientific Presentation Award" at the ENERDAY conference in recent years. Accordingly, both associations aim to promote scientific work in the energy industry on a local and national level.

Foreword

Dear participants of the 17th ENERDAY Conference on Energy Economics and Technology,

on behalf of the Chair of Energy Economics (EE2) at the Technische Universität Dresden and the Workgroup for Economic and Infrastructure Policy (WIP) at the Berlin Institute of Technology (TU Berlin), it is our pleasure to welcome you to this 17th edition of the ENERDAY, the International Conference on Energy Economics and Technology, with this year's focus on "*Energy crisis as an accelerator of a sustainable transformation?*". After a successful in-person conference with an unscheduled date in September last year, the time between last year's and this year's conference is significantly shorter as we return to our traditional conference time: the end of April and the beginning of May.

Now that the gas crisis with extreme prices is behind us, the impact on the further transformation of the energy system is unclear. In particular, the role of gas as an accompanying technology and provider of flexibility for the expansion of renewable energies is controversially debated. On the one hand, high fossil fuel prices encourage investments in sustainable energy technologies. Sustainable energies reduce political and economic uncertainties associated with fossil fuels and contribute to a diversification of the energy supply. On the other hand, policymakers have taken several short-term measures that have strengthened the lock-in of fossil fuels, such as significant investments in LNG infrastructure or the reactivation of phased-out coal-fired power plants.

Against this backdrop, it is essential to renew and deepen discussions on overarching issues and challenges associated with deep decarbonisation pathways, e.g., security of supply in the face of nuclear and coal power phase-outs and the role of disruptive technologies such as hydrogen as a means of scaling decarbonisation in the heating and transportation sectors. Last but not least, new climate policy measures merit particular attention and their sufficiency in reaching carbon targets in Germany, Europe, and globally.

- What are the critical challenges for adapting existing energy infrastructures?
- Which strategic decisions are necessary to achieve carbon neutrality?
- Which technologies figure to play a vital role?
- What means of diversification exist for reducing energy dependencies?

The 17th ENERDAY - Conference on Energy Economics and Technology is being organised as a face-to-face conference with the possibility of hybrid participation reserved for a few selected sessions. The ENERDAY provides a platform for discussing topics related to energy systems, markets, and policies, focusing on the role of existing energy assets and infrastructures in the context of the energy system transformation. Empirical analyses, modeling approaches, best practice examples, and policy and market design evaluations are particularly interesting. Furthermore, research on the economics of deploying new technologies is also relevant.

We hope this year's ENERDAY will provide a platform for strengthening the dialogue between those involved in economic and technical fields and serving to bridge the gap between practice and theory.

Scientific cooperation partners include the GEE, the German Chapter of the International Association of Energy Economics (IAEE). We are pleased to express our sincere gratitude to our premium supporters of this conference: 50Hertz Transmission GmbH, one of the four German transmission grid operators, and SachsenEnergie AG, the regional performance leader in the energy industry in Saxony.

As the conference organisers, we are delighted year by year by the high level of interest shown by the research community, which is reflected in the internationality of the participants and the number of submitted abstracts. We hope you enjoy the program and the high quality of the research presented. We want to thank all speakers for their contributions and the conference participants for their attendance.

We wish you an exciting and enriching in-person conference and fruitful discussions in this format,

Dominik Möst and Christian von Hirschhausen
& EE2 organizing committee

Instructions for joining the online hybrid sessions

Hybrid Session Room in Zoom

This year's conference includes two hybrid sessions (room HSZ/0004 and HSZ/0401) with presence and online participants.

The hybrid session is being held via the video conference software Zoom. It is recommended to download the software / app. For a seamless experience, it is recommended that you use the latest desktop version of Zoom (https://zoom.us/download).

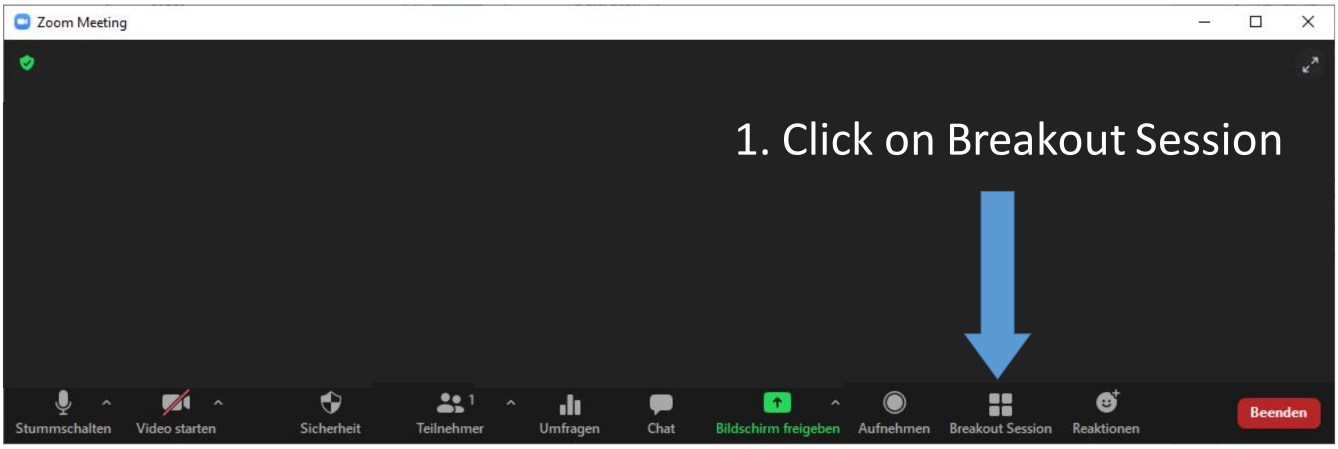
The dial-in link to the hybrid session rooms for online presentations and online registered participants are as follows.

Zoom-Meeting beitreten
https://tu-dresden.zoom.us/j/61997591931?pwd=SmVFa3N6czg1U2ZYYVl2dkc3ai9mQT09

Meeting-ID: 619 9759 1931
Kenncode: z*ty3d0F

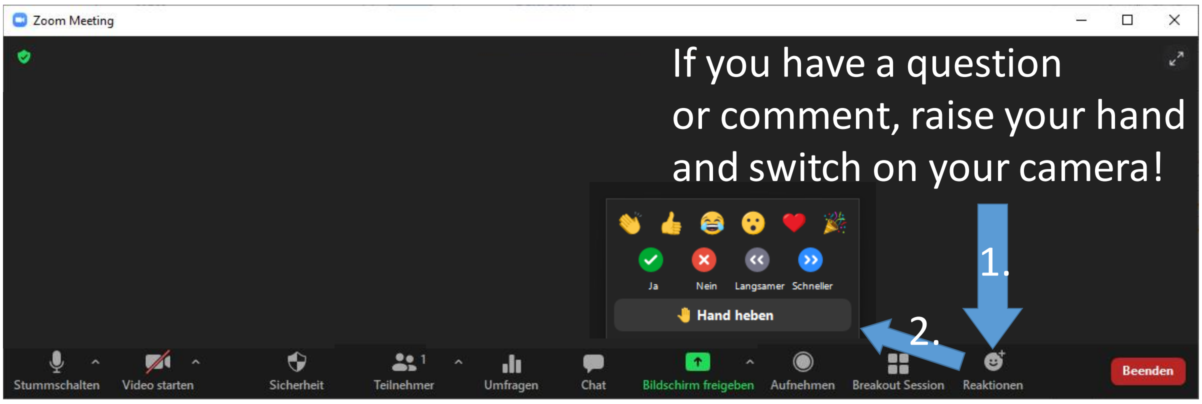
To participate in the two hybrid sessions, please enter:

- The main room for HSZ/0004
- The breakout room for HSZ/0401



Select the session you would like to join. You can switch from one session to another, but we recommend remaining in one session for its duration.

To ask a question or offer a comment, please raise your hand and wait to be prompted by the chair before switching on your camera. If you prefer to submit a question to be read aloud, you can use the chat function. The session chair will moderate the sequence between the discussant and Q&A.



ENERDAY 2023

The energy crisis as an accelerator of a sustainable transformation?

Pre-Conference-Dinner Informal Get Together	**Thursday, 4 May 2023,** **6:00 pm**	**Restaurant Kobers Chiavieri** (↗) Bernhard-von-Lindenau Platz 1, 01067 Dresden
Conference venue	**Friday, 5 May 2023,** **8:00 am – 05:45 pm**	**HSZ Hörsaalzentrum** (↗)

8:00	Registration, Coffee & Tea			
8:30	**Opening Address** (Room: HSZ/0004/H) Prof. Dr. Dominik Möst, TU Dresden			
9:00 - 9:45	**Keynote Talk** (Room: HSZ/0004/H, Chair: Prof. Dr. Dominik Möst, TU Dresden) **SachsenEnergie – our contribution to the German energy transition** Dr. Axel Cunow, SachsenEnergie			
9:45	**5 minutes for change of room**			
Parallel Session 1 (09:50 – 10:50)				
09:50 - 10:50	**Energy system modeling I** Room: HSZ/0004/H, **hybrid** Chair: Hendrik Scharf Assistant: Simon Koch	**Natural gas I** Room: HSZ/0401/H, **hybrid** Chair: Jens Maiwald Assistant: Niklas Haubold	**Hydrogen and flexibility** Room: HSZ/0301/U Chair: Steffi Misconel Assistant: Ole Sauerbrey	**Renewables and modeling** Room: HSZ/0304/Z Chair: Hannes Hobbie Assistant: Aaron Kaspar
9:50	**Uncertainty in energy system modeling - lessons from case-studies with GENeSYS-MOD** Karlo Hainsch, *Technische Universität Berlin*	**European economic impacts of cutting energy imports from Russia: A computable general equilibrium analysis** Sigit Perdana, *EPFL Lausanne*	**On assessing the value of decentral flexibility given different flexibility deployment and TSO-DSO coordination** Hendrik Kramer, *Universität Duisburg-Essen*	**The insurance value of renewable energies** Thibault Deletombe, *Université Paris Dauphine-PSL*
10:10	**Numerical optimisation of supply security in a cellular-structured district using solid-biomass-based hybrid systems** Lukas Richter, *Deutsches Biomasseforschungszentrum*	**European gas and LNG scenarios for winter 2023/2024 and beyond** Andreas Schroeder, *ICIS – Independent Chemical & Energy Market Intelligence*	**Hydrogen and heat storages as flexibility sources for a greenhouse gas-neutral German energy system** Thomas Schöb, *Forschungszentrum Jülich*	**A novel approach to generate bias-corrected regional wind infeed timeseries based on reanalysis data** Yannik Pflugfelder, *Universität Duisburg-Essen*
10:30	**Sustainable power systems transformation of industrial regions: Insights from energy system modelling** Sophie Pathe, *Ruhr-University Bochum*	**Europe's independence from Russian natural gas – Effects of a complete import stop on energy system development** Nikita Moskalenko, *Technische Universität Berlin*	~~**How much flexibility is needed by hydrogen power plants?**~~ ~~Philipp Hauser~~, **cancelled** *VNG AG*	**The effect of coarse weather data resolution on energy system model results** Matthias Zech, *DLR – Institut für vernetzte Energiesysteme*
10:50	**Coffee & tea break – 25 minutes**			

Parallel Session 2 (11:15 – 12:15)				
11:15 - 12:15	**Energy system modeling II** Room: HSZ/0004/H, **hybrid** Chair: Felix Jakob Fliegner Assistant: Simon Koch	**Natural gas II** Room: HSZ/0401/H, **hybrid** Chair: Maximilian Happach Assistant: Niklas Haubold	**Hydrogen and infrastructure** Room: HSZ/0301/U Chair: Lauritz Bühler Assistant: Ole Sauerbrey	**PV and storage** Room: HSZ/0304/Z Chair: Lisa Lorenz Assistant: Aaron Kaspar
11:15	**Investments in coupled energy sectors and market pricing** Johannes Wirth, *FAU Erlangen-Nürnberg*	**Long-term development of European natural gas markets - Scenario analysis using the global gas model (GGM) (online contribution)** Lukas Barner, *Technische Universität Berlin*	**A sector-coupled European energy system towards 2050 - Exploring the role of hydrogen pipeline infrastructure** Jonathan Hanto, *Europa-Universität Flensburg / TU Berlin*	~~**Smart energy protocol landscape in Germany**~~ ~~Christoph Parsiegla~~, **cancelled** *P3 Group*
11:35	**Energy imports and infrastructure in a climate-neutral European energy system** Fabian Neumann, *Technische Universität Berlin*	**Could we learn from our mistakes in the past? Comparing gas market forecasts from MAGELAN model with actual developments in reality** Andreas Seeliger, *Hochschule Niederrhein*	**Generation options & effects of sustainable hydrogen from offshore wind energy on the German energy system** Enno Wiebrow, *Technische Universität Berlin*	**Determinants of residential photovoltaic and battery storage adoption in Germany: an empirical investigation** Stephanie Stumpf, *KIT – Institute of industrial production*
11:55	**Green deal and carbon neutrality assessment of Czechia** Lukáš Rečka, *Charles University Praha*	**Expanding natural gas cross-border flows in Europe through the optimal use of the pipeline grid: a stylized model comparison** Christian von Hirschhausen, *Technische Universität Berlin*	**The economics of global green ammonia trade – "Shipping Australian wind and sunshine to Germany"** Kiana Niazmand, *FAU Erlangen-Nürnberg*	~~**Energy storage as enabler for the transition to a sustainable energy system: what will be the winning battery technology?**~~ ~~Jakob Gross~~, **cancelled** *P3 Group*
12:15 - 13:15	**Lunch break – 60 minutes**			

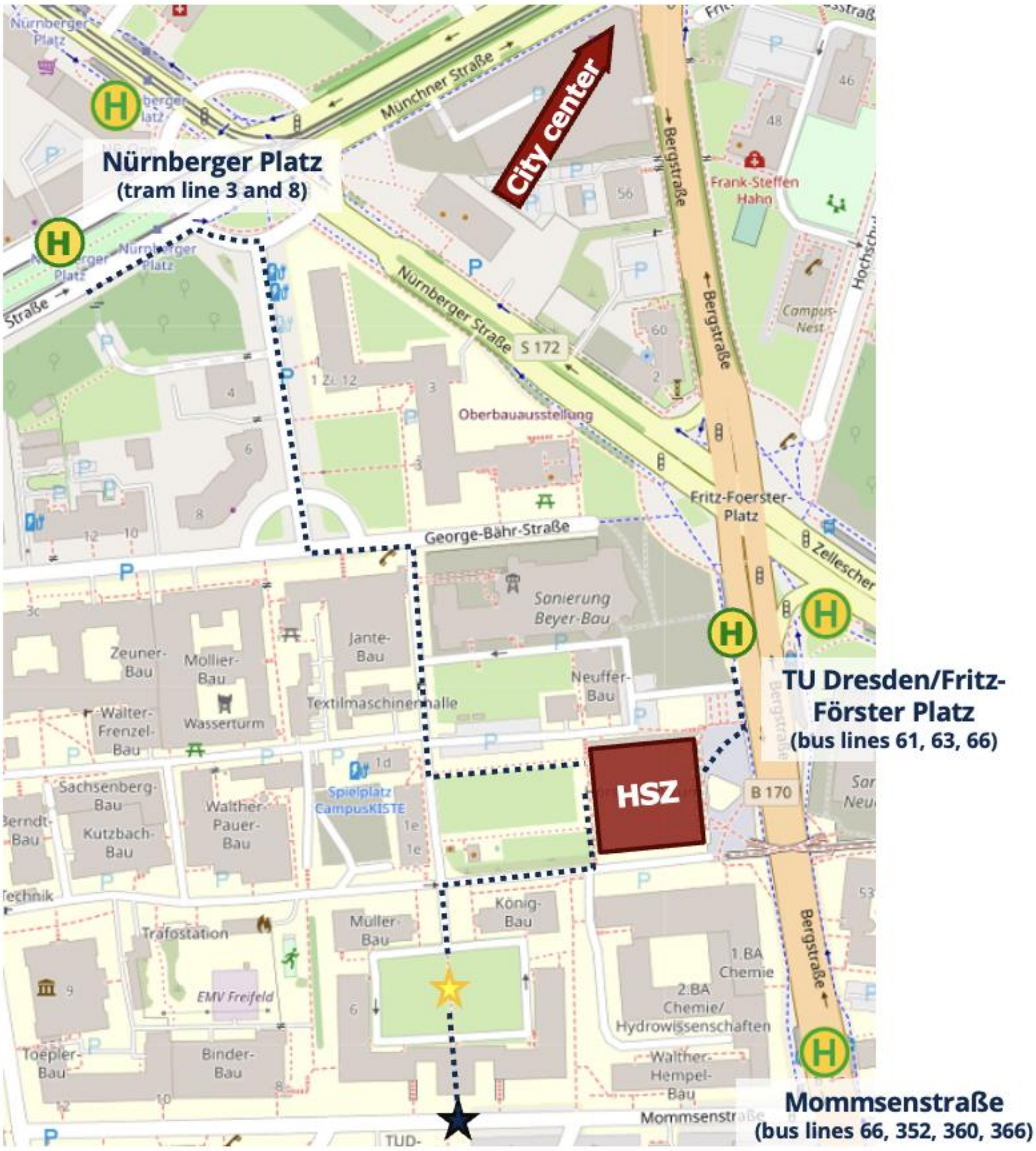
13:15 - 14:00	**Keynote Talk** (Room: HSZ/0004/H, hybrid, Chair: Prof. Dr. Christian von Hirschhausen, TU Berlin) **Trends in European and international gas markets in the energy sector transformation** Prof. Dr. Anne Neumann, NTNU			
14:00	**5 minutes to change rooms**			
Parallel Session 3 (14:05 – 15:05)				
14:05 - 15:05	**Energy system modeling III** Room: HSZ/0004/H, **hybrid** Chair: Andreas Büttner Assistant: Simon Koch	**Smart grid and tariffs** Room: HSZ/0401/H, **hybrid** Chair: Philipp Riegebauer Assistant: Niklas Haubold	**Demand response** Room: HSZ/0301/U Chair: Jannis Eichenberg Assistant: Ole Sauerbrey	**Renewables and infrastructure** Room: HSZ/0304/Z Chair: Mario Kendziorski Assistant: Aaron Kaspar
14:05	**Exploring the untapped potential of renewables and flexibility options in reducing CO_2 emissions - What will it cost?** Steffi Misconel, *EURAC Research*	**Smart network tariffs: Managing demand peaks in residential electricity distribution** Roman Hennig, *TU Delft*	**Gas demand in times of crisis: energy savings by consumer group in Germany** Oliver Ruhnau, *Hertie School*	**Potentials of parking and floating photovoltaics in Germany** Rachel Maier, *Forschungszentrum Jülich*
14:25	**Impact of non-linear CO2 price fluctuations on investments in the power sector** Erdal Tekin, *IER University of Stuttgart*	**Effects of electricity pricing schemes on household energy consumption A meta-analysis of academic and non-academic literature (online contribution)** Tarun Khanna, *Mercator Research Institute*	**The impact of demand-side mitigation measures in German passenger transport on the energy system transformation** Marlin Arnz, *Technische Universität Berlin*	**Solar prosumage: Interactions with the transmission grid** Mario Kendziorski, *Technische Universität Berlin*
14:45	**Navigating to a greener Europe through clean electricity procurement** Iegor Riepin, *Technische Universität Berlin*	**A methodological approach for developing smart grids - determining main drivers and match appropriate projects to meet local needs** Philipp Riegebauer, *BABLE GmbH*	**The role of dynamic electricity price contracts to utilise residential demand-side response to fight the energy crisis and ease the transformation to a renewable power system** Matthias Hofmann, *NTNU / Statnett*	**Spaghettigrids: Offshore grid development with a geographical information system - First results for Baltic and North Sea** Felix Jakob Fliegner, *50Hertz / TU Dresden*
15:05	**Coffee & tea break – 25 minutes**			

Parallel Session 4 (15:30 – 17:00)				
15:30 - 17:00	**Energy system modeling IV** Room: HSZ/0004/H, **hybrid** Chair: Constantin Dierstein Assistant: Simon Koch	**Energy transition** Room: HSZ/0401/H, **hybrid** Chair: Dimitrios Glynos Assistant: Niklas Haubold	**Decentralised energy supply** Room: HSZ/0301/U Chair: Lucas de la Fuente Assistant: Ole Sauerbrey	**Technology assessment** Room: HSZ/0304/Z Chair: Alexander Wimmers Assistant: Aaron Kaspar
15:30	**How reduction of energy demand can help to reach or reinforce German mitigation targets** Patrick Jürgens, *Fraunhofer ISE*	**Effects of fuel switching on electricity consumption and greenhouse gas emissions after the Russia–Ukraine War** Yeong Jae Kim, *KDI School of Public Policy and Management South Korea*	**Sustainable municipality modelling: Clustering-based bi-level optimization of a decentralized municipality energy and resource treatment infrastructure portfolio** Matthias Maldet, *EEG – Technische Universität Wien*	**Economics of nuclear power in decarbonized energy systems** Alexander Wimmers, *Technische Universität Berlin*
15:50	**The industry transformation from fossil fuels to hydrogen will reorganize value chains: Big picture and case studies for Germany** Nima Farhang-Damghani, *FAU Erlangen-Nürnberg*	**Defining green hydrogen: Does simultaneity benefit big players?** Nieves Casas, *RWTH Aachen University*	**Comparison of CO_2 and cost-optimised energy system for a residential building in Germany** André Eggli, *Hochschule Luzern*	**Efficient electricity distribution and sustainable energy management through Big Data analytics and machine learning** Andrej Somrak, *Troia d.o.o.*
16:10	**Short Coffee & tea break – 10 minutes**			
16:20	**Coherent transformation paths in energy system modelling - A case study for Germany** Toni Busch, *Forschungszentrum Jülich*	**Reviewing energy transition studies in the light of recent European gas market developments** Daniel Brunsch, *Universität Duisburg-Essen*	**Modelling district heating systems transition towards climate neutrality, case study of Poland** Maciej Raczyński, *AGH University of Science and Technology*	**Functional technology foresight: Case study for direct air capture and storage** Freia Harzendorf, *Forschungszentrum Jülich*
16:40	**At the borderline: An analysis of the electricity trade between Mexico and US (online contribution)** Lilia Garcia Manrique, *University of Sussex*	**Demand and generation in distribution grids: Future challenges and opportunities** Abhilash Bandam, *Forschungszentrum Jülich*	**Investigation of seasonal congestion situations in modern rural integrated distribution grids** Tom Steffen, *Technische Universität Hamburg*	**Effect of the energy crisis on short-term and long-term market design - an economic assessment** Maxime Amadio, *Compass Lexecon*
17:00	**End of parallel Sessions**			
17:30	**Group picture in front of the Fritz-Förster Bau (↗)**			
17:45	**Bus transfer to gala dinner (departing from Mommsenstraße)**			
Gala Dinner Official closing event and award ceremony	**Friday, 5 May 2023, 18:30 p.m.**	**Spitzhaus Radebeul (↗)** Spitzhausstraße 36, 01445 Radebeul		
23:30	**Bus transfer to Dresden central train station (departure from the gala dinner location)**			

Conference location on campus

Campus Navigator (↗)

Directions



Tram/Bus stations

Conference location (HSZ - Hörsaalzentrum)

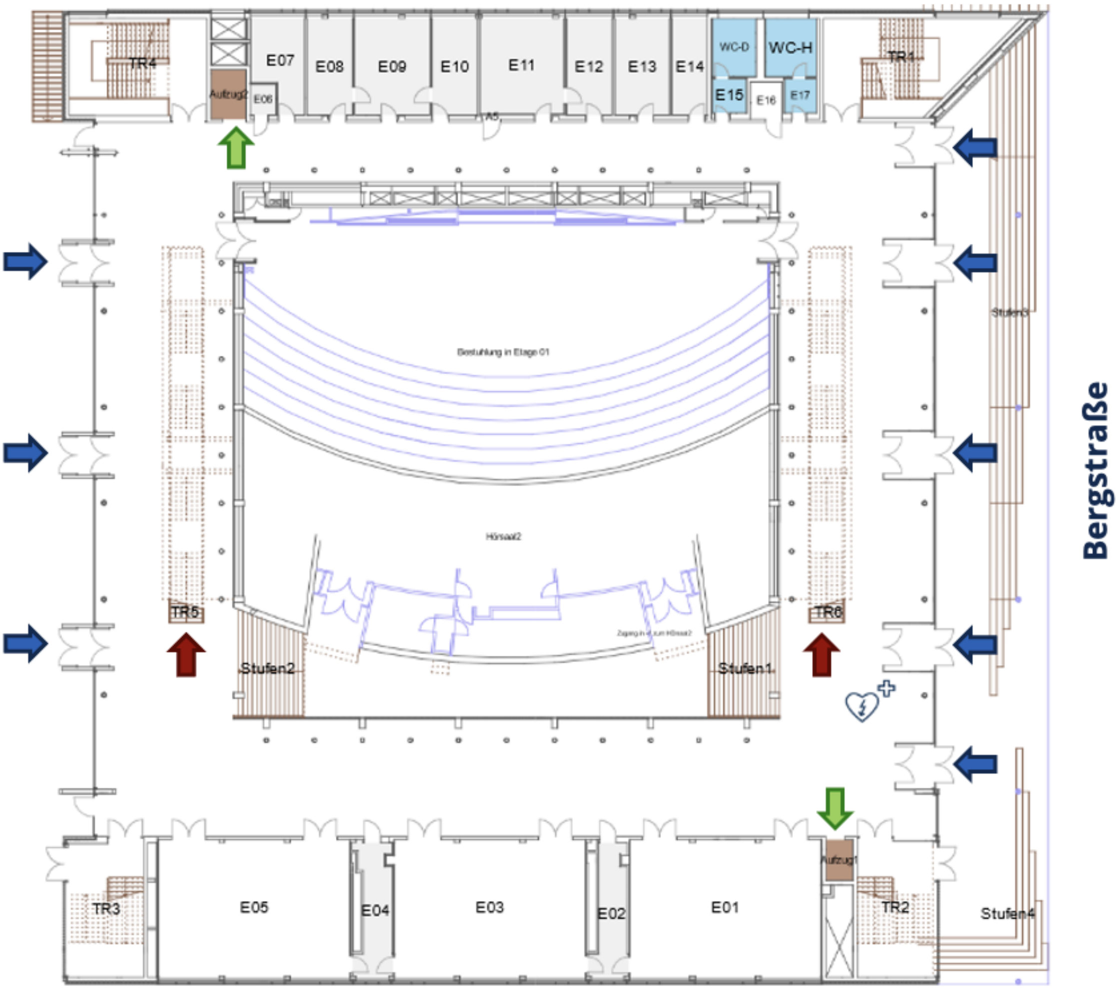
Location for group picture

Departure for the gala dinner

Conference rooms in building HSZ

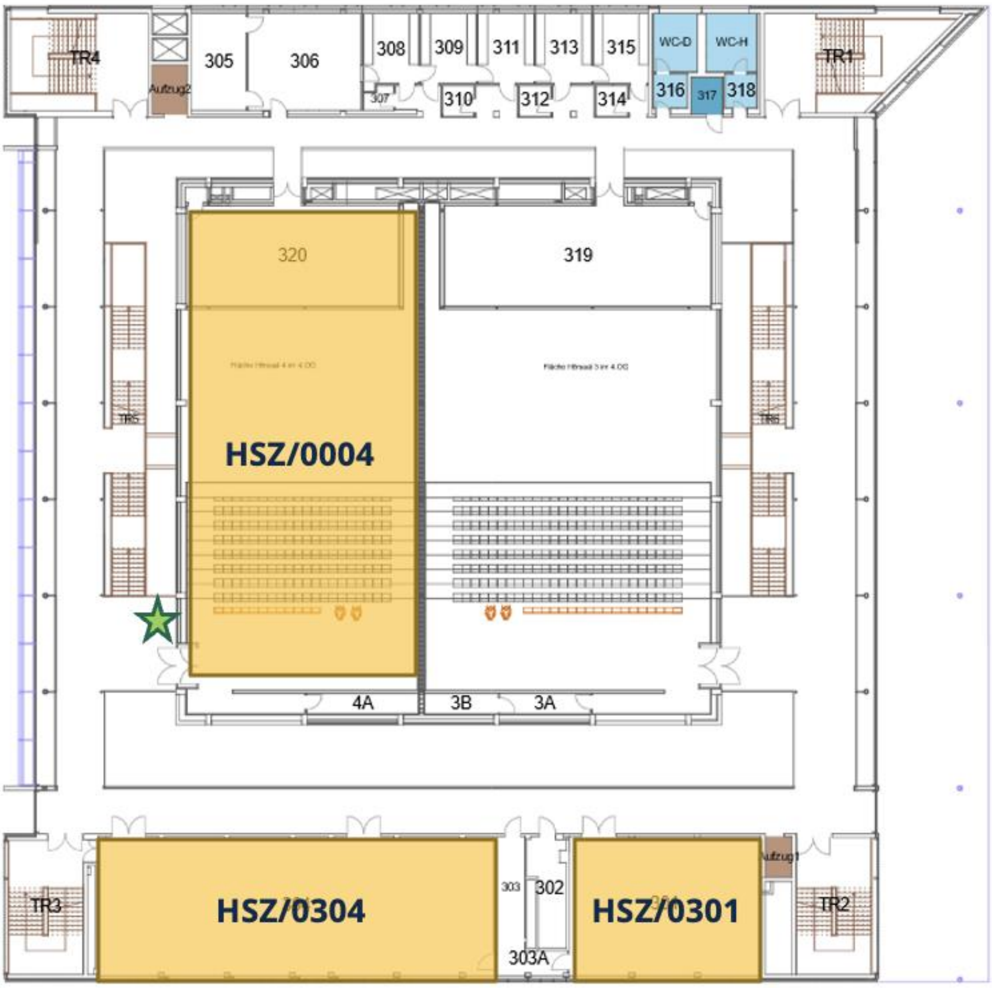
Campus Navigator (↗)

Ground floor (building entry)



- Building entrances
- Staircase to the conference office at the 3rd floor
- Elevator

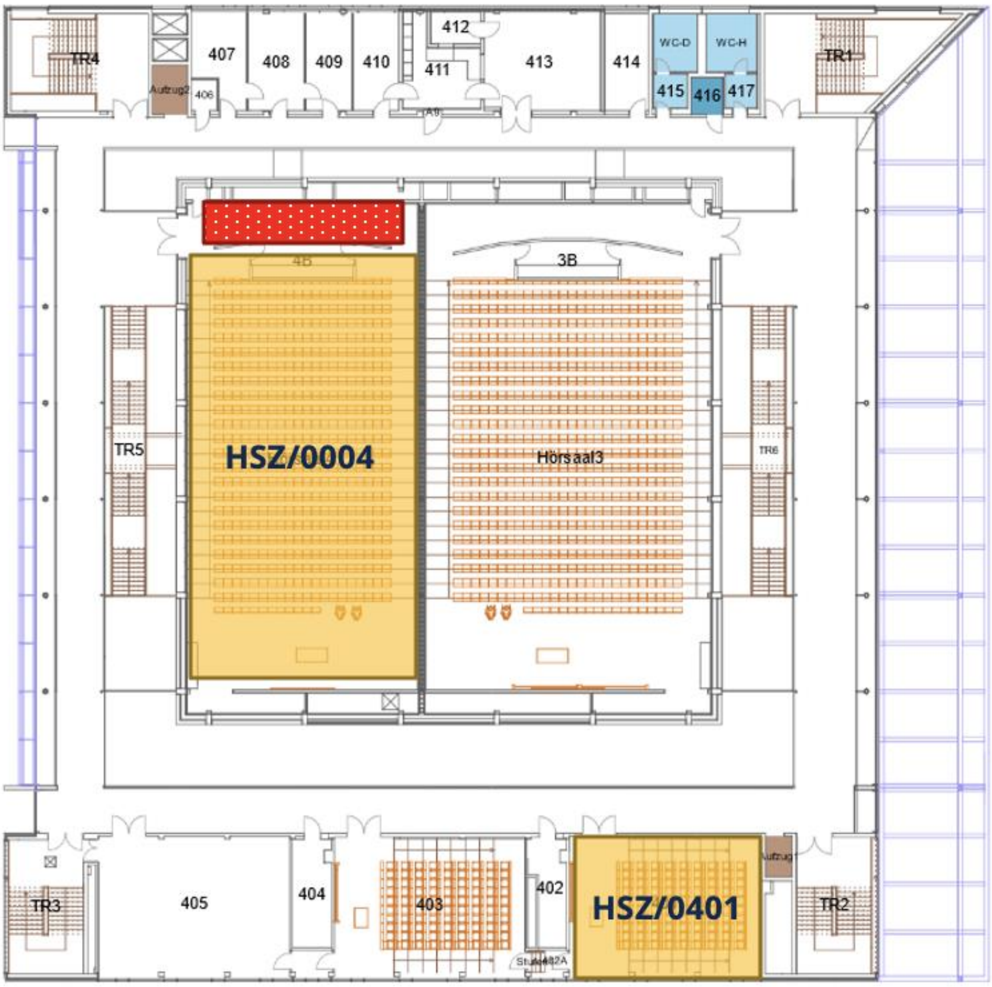
Conference floor – 3rd floor



Conference rooms

Conference office

Conference floor – 4th floor



Conference rooms

Wardrobe

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Keynote 9:00 – 9:45

Room: HSZ/0004, hybrid
Chair: Prof. Dr. Dominik Möst

SachsenEnergie – our contribution to the German energy transition

Dr. Axel Cunow[1]

[1]*SachsenEnergie*

Session 9:50 – 10:50
Energy system modeling I

Room: HSZ/0004, hybrid
Chair: Hendrik Scharf

Uncertainty in energy system modeling - lessons from case-studies with GENeSYS-MOD

Karlo Hainsch, *Technische Universität Berlin*

Numerical optimisation of supply security in a cellular-structured district using solid-biomass-based hybrid systems

Lukas Richter, *Deutsches Biomasseforschungszentrum*

Sustainable power systems transformation of industrial regions: Insights from energy system modelling

Sophie Pathe, *Ruhr-University Bochum*

Uncertainty in energy system modeling - lessons from case-studies with GENeSYS-MOD

Karlo Hainsch[1]

[1]*Technische Universität Berlin, k.hainsch@tu-berlin.de*

Keywords: decarbonization, green hydrogen, offshore wind, energy system modeling, GENeSYS-MOD

Motivation

Considering the tremendous effort necessary to transform the energy system, policy and decision makers rely on clear and adequate communication of findings and conclusions by researchers and practitioners. However, the current energy crisis showcases that reality is likely to look very different from model results and outcomes which highlights the requirement for model(er)s to provide insights about the system itself instead of single numbers and values. This raises the question of what best-practice examples for energy system modeling exercises are and which common findings and no-regret options can be communicated to policy and decision makers.

Methods

Within the context of energy system modeling, various types of uncertainty must be accounted for. Following the classification of Peltz et al., we define three types of uncertainty: (i) data uncertainty regarding parameter values of the past, present, and future, (ii) interaction uncertainty which describes possible inaccuracies in mathematical model formulation, and lastly (iii) system uncertainty since not all possible components of the future energy system are known to date. Different approaches exist in the field of energy system modeling, ranging from scenario over sensitivity analysis to stochastic optimization – each suited to deal with a different type of uncertainty (Figure 1, left). Therefore, this paper synthesizes findings from numerous case studies using the open-source energy system model GENeSYS-MOD to define and highlight common findings across multiple studies. Scenario analysis, sensitivity analysis, model comparison, and myopic foresight exercises are performed to address the transformation of the German and European energy system. In doing so, robust findings and no-regret options can be identified which can be used by policy and decision makers to base their decisions on. Additionally, all case-studies, data, and model code are published fully open source, allowing other researchers and practitioners to validate and verify the findings.

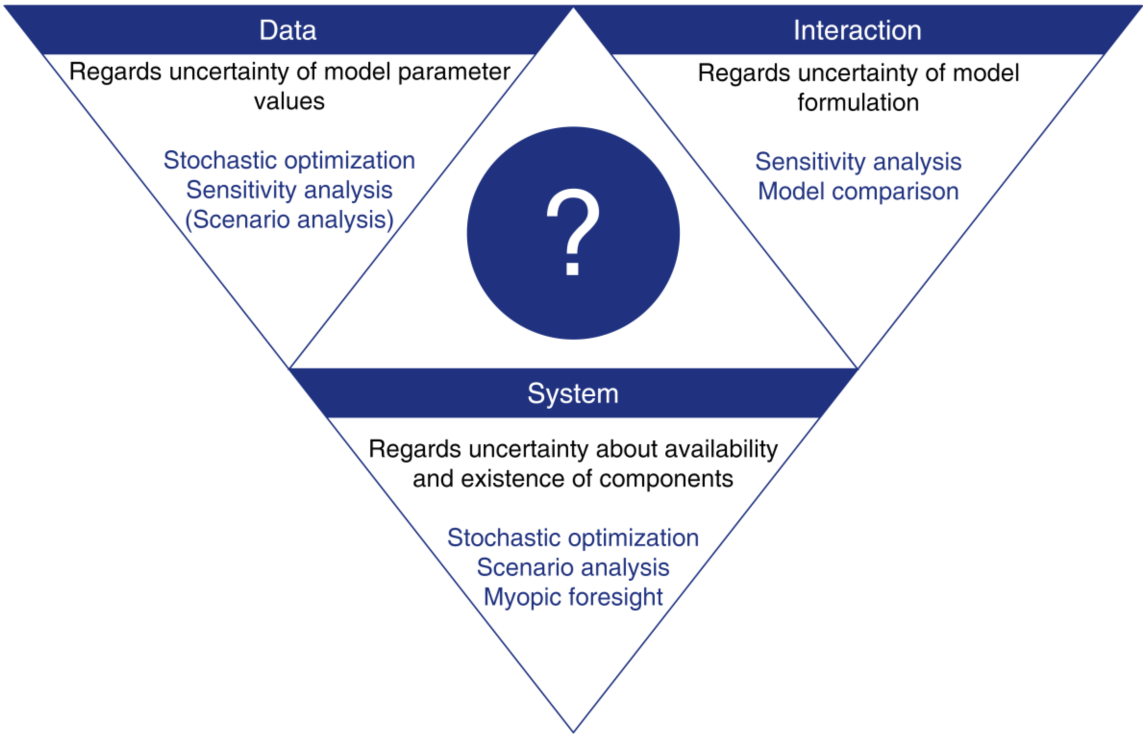

Figure 1

Results

First, best-practices with respect to modeling 100% renewable energy scenarios are identified. Open source is a major cornerstone; however, it is not applied sufficiently, which leaves many open questions for policy makers or other non-modelers. Additionally, sectoral, regional and temporal disaggregation levels show high influence on model results but are typically not described adequately.

Second, challenges for specific countries and unions of countries (e.g., European Union) are highlighted. To help with emission reduction, energy demand and carbon prices prove to be two levers, which can significantly assist with that goal. As illustrated in Figure 2 (right), a sensitivity analysis on the German energy system shows that emissions are significantly affected by a carbon price in the intermediate term, while energy demand reduction show high effect long-term. Policy makers should focus on policies targeting these areas to achieve decarbonization targets.

Third, general no-regret options are identified, regardless of input assumptions or methodology, including: no need for fossil fuel capacity expansion, the need for immediate action, and electrification of all sectors. Overall, robust energy system analysis approaches are required to inform and assist policy makers and to transfer scientific findings into the political debate and decision process.

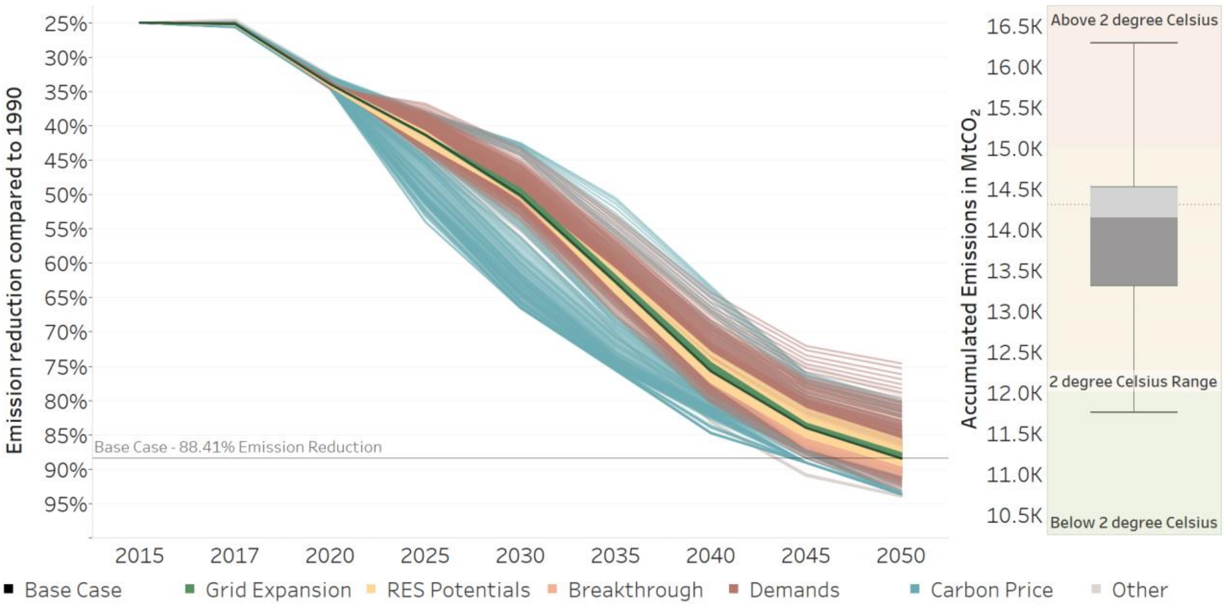
Emission reduction compared to 1990
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
Base Case - 88.41% Emission Reduction
2015
2017
2020
2025
2030
2035
2040
2045
2050
Accumulated Emissions in MtCO2
16.5K
16.0K
15.5K
15.0K
14.5K
14.0K
13.5K
13.0K
12.5K
12.0K
11.5K
11.0K
10.5K
Above 2 degree Celsius
2 degree Celsius Range
Below 2 degree Celsius
Base Case
Grid Expansion
RES Potentials
Breakthrough
Demands
Carbon Price
Other

Figure 2

Numerical optimisation of supply security in a cellular-structured district using solid-biomass-based hybrid systems

Lukas Richter[1]

[1]*Deutsches Biomasseforschungszentrum, lukas.richter@dbfz.de*

Keywords: cellular approach, bioenergy, hybrid systems, multi-agent system, sector coupling

Motivation

At the latest since the 2022 energy crisis, the topics of supply security, resilience and energy prices have been omnipresent. Without fossil fuels, Germany is dependent on a rapid expansion of renewable energies, which poses major challenges for the energy system. Volatile energy sources such as wind and solar are becoming the pillars of the energy transition, but they are only flexible to a limited extent. In order to use the individual energy source optimally, customised concepts are required with different volatile and controllable renewable energy sources in combination with storage technologies. This providing of energy by preferably multiple small-scale producers instead of a few large power plants increases the variability of the energy system. In order to avoid problematic grid conditions, these decentralised energy assets have to be managed properly, which leads to a high complexity in control and organisation. A cross-sectoral organisational structure for this goal could be the so-called cellular approach. In addition to this approach, it still needs to be clarified how the future energy plant park in the cells can look like in order to ensure resilient and cost-saving operation. Solid biomass in particular could play a major role, as it can generate heat and electricity on demand, unlike most other renewable energy sources. Future urban heat supply will mainly be based on district heating systems with multiple producers. However, in rural areas with lower heat demand density, decentralised heat supply could still be the most cost-effective. This is where demand-oriented use of biomass in hybrid systems can play an important role in maintaining security of supply. In this context, a value-optimised integration of solid biomass-based hybrid systems is being researched at DBFZ. The aim is to identify and develop climate-friendly and cost-efficient solutions that offer a high level of supply security in both the electricity and heat sectors.

Methods

In this work, an optimisation algorithm is presented that considers the detailed modelling of hybrid systems as well as the autonomous and subsidiary properties of the cellular approach.

The first step is a system optimisation which was carried out with the Open Energy Modelling Framework "oemof". The basis of the modelling and optimisation is a representative energy cell that reflects the building structure, weather and demand profiles as well as potentials for renewable energies in rural areas. This cell covers the area of a district and consists of several smaller cells at the building level. The modelling is a bottom-up approach with focus on the local level and detailed illustrations of the occurring processes. This results in a mixed-integer optimisation based on cost efficiency, which is used to determine the optimal plant configuration as well as plant and storage schedules for a calendar year depending on the specific configuration and constraints. This first step provides the optimal plant configuration. However, a single cell is not sufficient to illustrate the features of the cellular approach such as subsidiarity and autonomy. Therefore, the goal of the second stage is to find the optimum of each cell at the lower level in order to generate a system optimum as the sum of the local optima. One way to implement this aspect in a model is with multi-agent systems. In the second phase, each agent therefore represents an energy cell. An agent has the primary goal of balancing supply and demand based on the asset park from the first stage. Only when this goal of intra-cell supply security has been achieved or balancing is not possible, the agents can interact with each other to ensure security of supply at the current cell level as a secondary goal. With this secondary goal, each agent has the opportunity to generate additional revenue by participating in a local energy market, which increases the agent's personal profitability and creates a local optimum.

Results

This work presents a conceptual combination of the cellular approach with a biomass-based hybrid system which could have a major impact on rural defossilization. To this end, a comprehensive two-stage optimisation model is developed which incorporates the characteristics of the cellular approach in form of a high degree of autonomy and subsidiarity. This is used to show how the economic efficiency of individual actors is affected by a variation of self-sufficiency indicators and in the biomass price. It also demonstrates at which level of self-sufficiency and biomass price the use of biomass can contribute to security of supply. This could aid to maximize the impact of locally available biogenic resources, whose potential is limited. The focus of the planned presentation is on the concept of a local energy market and the underlying interaction rules as a basis for the multi-agent system that builds on it.

Sustainable power systems transformation of industrial regions: Insights from energy system modelling

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Keywords: energy system model, life cycle assessment, multi-objective optimization, energy transition, structural change

Motivation

Motivated by environmental issues, foremost climate change, the demand for sustainable solutions in the energy sector is growing. A way to identify and assess sustainable solutions in the energy sector is to consider environmental impacts in energy system models (ESMs). The consideration of direct CO2- or greenhouse gas emissions in optimizing ESMs is quite common, whereas other environmental impacts are often neglected. However, this approach does not provide enough information to assess the environmental sustainability of energy systems or for comparison among renewable energy (RE) technologies. Previous research shows that for REs the environmental impacts shift from greenhouse gas emissions to other impact categories, for example to the intensive use of critical metals or land use because of relatively lower energy densities of REs. Impacts also shift from the use phase to the construction phase. We address such issues by combining an ESM with a life cycle assessment of energy conversion technologies. Doing this, we implement aspects highlighted as important, namely the consideration of the entire life cycle and the consideration as well as the optimization of various environmental impacts, in addition to costs, by determining a pareto front. The consideration of environmental impacts in addition to system costs through multi-objective optimization in an ESM provides valuable insights into the interrelationships of those objectives. We apply the multi-objective optimization to the Central-European power system (twelve countries, see Figure 1). Thereby, we particularly focus on the Rhenish Mining Area in western Germany in the year 2040, as a heavily industrialized region undergoing significant structural change. The region is characterized by lignite mining and lignite-fired power plants, which will be phased out by 2030 according to legislation, and energy-intensive industry, i.e. high energy densities on the supply and demand side.

Figure 1: Spatial resolution of the model. Each colored area represents one node.

Methods

The optimization objective of ESMs is usually the minimization of the overall energy system costs while satisfying the energy demand in each time step and complying with given operating constraints. We combine the ESM Backbone with a life cycle assessment (LCA) to consider various environmental impacts in addition to system costs. Backbone is a mixed-integer linear optimization framework implemented using General Algebraic Modeling System (GAMS). It can be used for investment planning and scheduling and features a high level of adaptability. The implementation of LCA in Backbone consists mainly of the integration of LCA data into Backbone, the implementation of an alternative objective function to minimize environmental impacts and the implementation of additional constraints to limit environmental impacts. This enables the determination of potential environmental impacts in addition to system costs and essentially results in an LCA of the energy system. It is also possible to optimize these environmental impacts using alternative objective functions or to limit them using constraints. Furthermore, multi-objective optimization is implemented to optimize system costs and an environmental impact simultaneously. Using the augmented Îµ constraint (AUGMECON) method, this leads to multiple pareto-optimal solutions that are displayed in a pareto front.

Results

We present selected preliminary results from the application of LCA in Backbone to transform the Central-European power system, focusing on the Rhenish Mining Area (RMA). Optimizations are performed for system costs and three exemplary environmental impacts: global warming potential (GWP), urban land occupation potential (ULOP) and metal depletion potential (MDP) (see Figure 2). Only a limited number of technologies are used in the RMA. For the environmental impact objectives, onshore wind is installed almost exclusively, while the generation mix relies mainly on gas for the cost objective. Options for power storage in the system are pumped hydro, battery, and hydrogen storage. For the RMA, storage is not used for minimization of system costs. When minimizing GWP and ULOP, mainly battery storage is used, and when minimizing MDS , only hydrogen storage is used due to the lower use of relevant metals in its construction compared to battery storage. Storage usage is highest when minimizing the GWP. The electricity demand of the RMA is only covered locally with extensive use of gas. For larger shares of RE, electricity is imported from other regions. It is indicated that industrial regions as the RMA, where high demand-side energy densities have arisen due to high fossil energy densities, can no longer be supplied locally with RE and its correspondingly lower energy densities, for lack of land potentials in such industrial regions. Figure 3 demonstrates an example of multi-objective optimization. It displays the pareto front obtained from optimizing system costs and GWP and showcases how abatement costs vary with different GWP optimization targets. The steep cost increase observed for low GWP values highlights the significant rise in abatement costs when striving for extremely low greenhouse gas emissions. However, it's important to note that considerably lower GWP values can be achieved at a relatively low additional cost compared to a pure cost optimization approach.

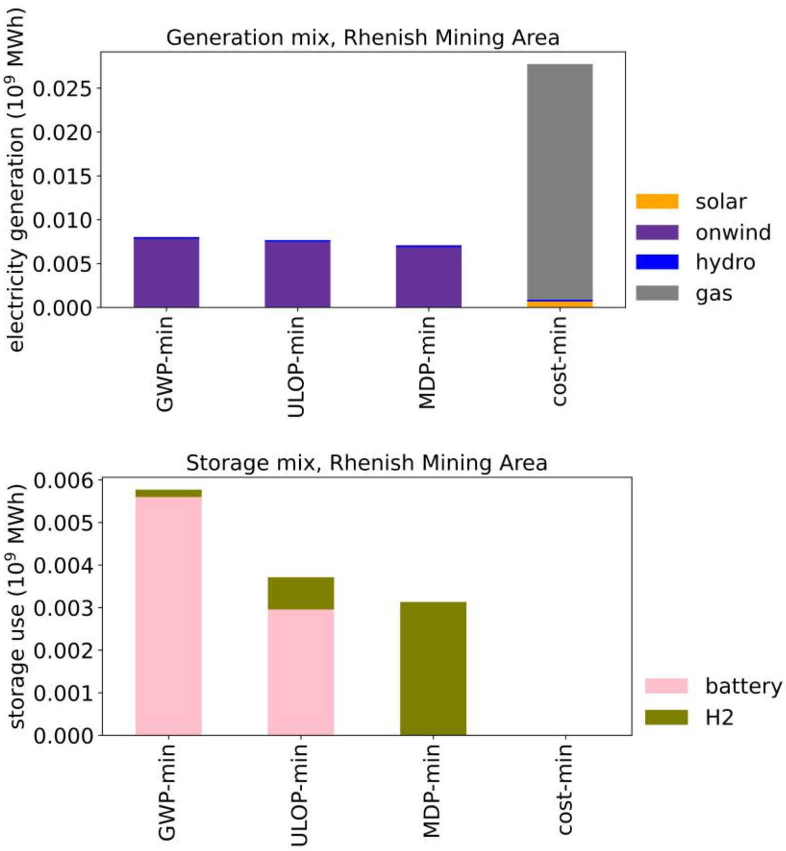

Figure 2: Electricity generation mix and electricity storage mix of the Rhenish Mining Area in the year 2040 (withdrawn electricity amount) for minimization of Global Warming Potential (GWP), Urban Land Occupation Potential (ULOP), Metal Depletion Potential (MDP) and total system costs.

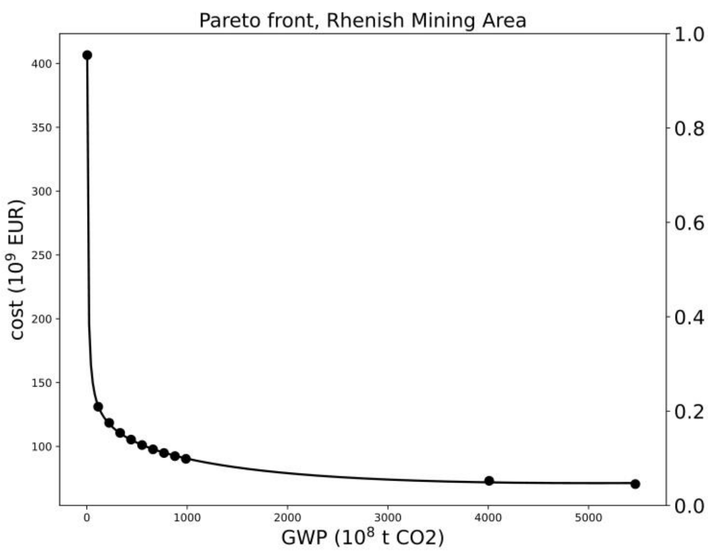

Figure 3: Pareto front representing the optimization of system costs and Global Warming Potential (GWP) for the Rhenish Mining Area in the year 2040.

Session 9:50 – 10:50
Natural gas I

Room: HSZ/0401, hybrid
Chair: Jens Maiwald

European economic impacts of cutting energy imports from Russia: A computable general equilibrium analysis
Sigit Perdana, *EPFL Lausanne*

European gas and LNG scenarios for winter 2023/2024 and beyond
Andreas Schroeder, *ICIS – Independent Chemical & Energy Market Intelligence*

Europe’s independence from Russian natural gas – Effects of a complete import stop on energy system development
Nikita Moskalenko, *Technische Universität Berlin*

European economic impacts of cutting energy imports from Russia: A computable general equilibrium analysis

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Keywords: European Union, Russia, computable general equilibrium model, Fit for 55 package, energy imports ban

Motivation

Russia's current invasion of Ukraine affects the world in all aspects and raises global concerns. Many countries have imposed economic sanctions on Russia to speed up the end of this devastating conflict. Sanctions unquestionably come with consequences that are likely to be detrimental to Russia in this case and to countries that are imposing them. This paper aims to analyse those consequences for the EU given its current position to restrict its import from Russia, sanctioning policies chosen, and its dependency on Russian exports. Here the analysis focuses on the EU energy embargo to Russia and its cost. Following the adoption of the 5th package of restrictive measures to ban coal import in all forms from August 2022 and the 6th package to restrict oil import to be completed in 2023, this paper analyses the implications for energy prices of such an embargo, the economic cost to European citizens and the impact on the Russian economy.

Methods

This study uses the latest modification of GEMINI-E3 based on the study of Bernard and Vielle (2008). The model incorporates a multi-country, multi-sector, recursive dynamic computable general equilibrium model with backward-looking (adaptive) expectations. The current version is built on the GTAP 10 database (Aguiar et al., 2019) with the year 2014 as reference. For analytical purposes, the regional aggregation of this version covers the EU, the US, China and the rests of the world, which is represented by 8 countries and regions. Scenario design for reference case uses a more updated complementary climate-development of CD-Links policies database (McCollum et al. 2018, Roelfsema et al. 2020), with harmonized assumptions detailed in our previous work of Giarola et al. (2021) and Sognaes et al. (2021). The baseline or reference scenario is constructed based on the EU's current policies, including the latest EU climate targets of Fit of 55 Packages. The implications of EU energy restriction is estimated by taking into accounts the latest restriction on coal and oil imports, and develop additional scenarios for restriction on natural gas based on the latest progress of 2022.

Results

The impact of the current embargo on oil and coal is quite substantial. The embargo imposes an adverse supply effect as the price of coal and oil increases. It costs 1677 US$ per citizen or 0.73% of household consumption from 2022 to 2030. Extending an embargo on natural gas doubles this cost, thus confirming previous studies pointing out the challenge of reducing EU gas imports from Russia. Given the current constraints of additional import capacities from non- Russian producers and assuming restriction of natural gas import will be implemented within the same time frame as oil, the cut-off of Russian gas import has a more significant detrimental impact compared to coal and oil embargo only. Our analysis finds that coal will play a central role in energy replacement in the short term, especially in electricity generation. Within the current embargo scheme, coal consumption increases to offset the recent declining gas demand trend. This pattern persists when the embargo is extended to include natural gas. With the current capacity constraint of gas exports from non-Russian partners and limited additional contributions of renewables, the likelihood of replacing gas with coal power plant is still high in the short term, even in a more stringent abatement target.

European gas and LNG scenarios for winter 2023/2024 and beyond

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Keywords: gas, LNG, security of supply

Motivation

Will European storage be sufficiently eeplenished next year and what should the LNG market expect for winter 2023 and the subsequent summer? ICIS will undertake and present a three-part analysis that will investigate how well-prepared Europe will be for the 2023-24 gas winter; what likely outcomes that winter will have on storage levels; and finally, how the European security of supply situation of that winter will resonate across the global LNG market.

Methods

The analysis draws on weather-driven consumption forecasts and a European gas market optimization model with daily resolution looking two years ahead. The model optimizes European LNG versus pipeline import and it considers weather effects on demand, infrastructure capacity constraints, storage obligations, long-term contracts, capacity bookings as well as supply cost. The base scenario is represented by Russian supplies limited to winter 2022/23 flow levels while a second scenario studies the impact of a complete halt in Russian supplies. The analysis takes into consideration different weather forecasts as well as demand response.

Results

Using proprietary modelling, ICIS will first undertake an analysis of the European gas market to evaluate how well replenished conventional storages will be across the continent by spring 2024. We will draw on the events of Winter 2022-23 and the first half of 2023 to predict likely storage levels for the end of the next winter. We will assess how quickly those stocks will be drained during the heating season, looking at different demand views and changes in pipeline supply. Again, events of winter 2022-23 will be used to inform withdrawal-behaviour in relation to an extremely high-gas price environment. This will then inform the third section of our analysis, which will forecast monthly LNG demand into Europe through the winter of 2023-24, again leveraging ICIS's proprietary modelling capability. It will also highlight infrastructure bottlenecks as well as the impact European LNG demand will have upon non-European markets. We will conclude by stressing the risks as well as opportunities LNG market participants should keep in mind for the upcoming nine months.

Europe's independence from Russian natural gas – Effects of a complete import stop on energy system development

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Keywords: energy security, energy system modeling, decarbonization, Russia, natural gas

Motivation

With the disruption of Russian natural gas imports due to Russia's war on Ukraine, Europe's energy reliance on Russia is more apparent than ever. Before the COVID-19 pandemic, natural gas imports from Russia covered about 23.7% of Europe's energy supply. Even after one year of war, 8% of natural gas is still imported from Russia. To tackle the resulting challenges of limited gas supply from Russia, short and long-term effects need to be investigated. High energy prices and the fear of gas shortages in winters stimulate the discussion whether Europe can manage without any natural gas imports from Russia. How such a European energy system could look like and whether it can function using alternative technologies and trade shall be examined in this paper.

Methods

The Global Energy System Model (GENeSYS-MOD) is used to represent the future European energy system for this paper. GENeSYS-MOD is a linear, cost-optimizing, techno-economic energy system model, publicly available with code and data. The sectors electricity, heat, transport and their interdependencies are considered to model a sector-coupled energy system towards deep decarbonization. Figure 1 shows a stylized illustration of the model's structure. The European model version 3.1, developed in the H2020 project openENTRANCE serves as the basis for this study. With the help of international partners, comprehensive country-level data was collected within the project, serving as a baseline. Additionally, this study improves the modeling of international gas infrastructure within Europe. Improvements to the representation of hydrogen technologies strengthen the model's possibility to substitute Russian natural gas. These changes include e.g., retrofitting of natural gas pipelines to also carry hydrogen. This could be especially important considering renewable hydrogen as a viable short- to medium-term alternative. In order to investigate an independence from Russian natural gas, three gas supply scenarios with varying amounts of available natural gas from Russia are compared. Based on the given data and model formulations, the model then decides what the cost-optimal energy system looks like and what alternatives to invest in.

Results

This paper intends to display possibilities of a European energy system without natural gas imports from Russia. Overall, it will show in which time period the model invests in which alternatives to identify the cost-optimal energy system until 2050. LNG imports from Turkey and outside Europe will play an important role, especially in view of the scarce natural gas resources within the continent. Especially in the heating sector, natural gas is difficult to replace in the short term. Therefore, it is assumed that the import of LNG will be the first alternative, before switching to other technologies such as heat pumps. In the electricity sector, natural gas can be more easily substituted. Although coal-fired power generation would potentially need to increase in the short term, the transformation towards 100% renewables could be accelerated, especially in the long run. In addition to alternative technologies, trade within Europe is another important factor that can contribute to the phase-out of Russian natural gas. Since especially Eastern European countries have only limited access to LNG, trade through continental measures is necessary. It is assumed that this will further lead to an increased trade across Europe in order to ensure an optimal energy system.

Session 9:50 – 10:50
Hydrogen and flexibility

Room: HSZ/0301
Chair: Steffi Misconel

On assessing the value of decentral flexibility given different flexibility deployment and TSO-DSO coordination
Hendrik Kramer, *Universität Duisburg-Essen*

Hydrogen and heat storages as flexibility sources for a greenhouse gas-neutral German energy system
Thomas Schöb, *Forschungszentrum Jülich*

How much flexibility is needed by hydrogen power plants?
Philipp Hauser, *VNG AG*

On assessing the value of decentral flexibility given different flexibility deployment and TSO-DSO coordination

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Keywords: market modelling, future energy system, 2050, net-zero emission system, re-dispatch, congestion management, energy system flexibility

Motivation

Increased flexibility in the energy system through storage and demand side flexibility allows a better integration of intermittent renewable energy supply. Digitalization as well as information and communication technology are expected to act as enabling factors for decentral flexibility options to support system operations. Mandatory smart metering has been introduced to make use of and incentivize the operation of small units in a system-supportive manner. At a system operations level, TSO-DSO coordination is mostly expected to encourage such operation. In contrast to central storage facilities or controllable generation technologies that are specifically installed to provide energy during periods of scarcity, decentral storage units are already installed as of today. Residential storage is deployed by households to increase self-autarky and self-consumption. The share of electric vehicles in providing decentralized flexibility is anticipated to grow in the coming years. Given different years of deployment, decentral technologies will only partly be capable of providing flexibility capabilities. Furthermore, existing studies modeling endogenously decentral demand side flexibility either focus on local distribution systems (e.g., smart grids or micro grids) or on the transmission grid with aggregated flexibility potentials at high voltage substations (e.g., national grid system operation studies). This work brings both elements together, covering transmission and distribution grids based on a detailed data set. It addresses the question to what extent decentral flexibility at the local level may help to mitigate regional grid bottlenecks as well as congestions in the transmission grid. Different scenarios regarding the degree of decentral flexibility provided, as well as different extents of TSO-DSO coordination are assessed.

Methods

The study makes use of an energy market and system model and simulates a German 2050 net-zero emission scenario. First, the dispatch and prices in a zonal market setting are computed considering the available technologies and a intertemporal market clearing process with limited foresight. Second, the model is re-run considering the grid infrastructure constraints of a 2050 scenario to prohibit grid overloading, i.e. re-dispatch is performed. The market model is formulated as linear optimization model in the programming language, Julia. Schedule adjustments between the market and the system operations are conducted (re-dispatch). Both, market and re-dispatch run are carried over in a rolling planning approach. Storage filling level deviations caused by the second run are correspondingly considered in the next market clearing iteration. Besides the transmission grid, five regions are modeled with distribution grids. These areas include decentral flexible units such as heat pumps, electric vehicles and storage units. The (dis)charging schedules of flexibility providers are determined endogenously to minimize system cost in the market run and to reduce congestions in the second optimization. Scenarios for varying contributions of flexibilities from different technologies as well as different TSO-DSO exchange scenarios given imperfect TSO-DSO coordination are applied to assess the effects of partial flexibility, as well as partial energy exchange schemes.

Results

Preliminary results indicate that decentral demand side flexibility is going to be employed to utilize the distribution grid more closely at its (n-1) operation boundaries as with the increased number of flexible units nodal power infeeds and outtakes may be modified to control line loadings in accordance with Kirchhoff's circuit laws. Whereas congestions can be mitigated on local level, the flexibility potential is not sufficient to relieve grid congestions on the transmission level, particularly dependent on the magnitude of flexibility capabilities and TSO-DSO coordination schemes. These results have implications for the future kind of TSO-DSO-coordination: Computation of load flows at distribution grid/system level is becoming an important and computationally cumbersome task and must be managed accordingly. Decentral algorithms, parallel computing and/or decomposition techniques for optimization are correspondingly worthwhile topics for further research.

Hydrogen and heat storages as flexibility sources for a greenhouse gas-neutral German energy system

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Keywords: energy system analysis, greenhouse gas neutrality, hydrogen storages, heat storages, sector coupling

Motivation

To limit global warming, Germany is obligated by the Federal Climate Change Act [1] to achieve greenhouse gas neutrality by the year 2045. Achieving this target requires a rapid and thorough transformation of the entire German energy system. Considering the current energy crisis, more focus is put on the security of the energy supply in a future energy system. Particularly, the phase out of controllable fossil powerplants and expansion of volatile renewable energy sources in the electricity sector will pose a challenge for security of supply. As Stolten et al. [2] show, an expansion of hydrogen or biomass-fueled powerplants and electricity storages is needed to keep volatile electricity generation and demand in balance. Additionally, sector coupling offers the possibility to use hydrogen and heat storages for balancing the intermittent supply through photovoltaic plants and wind turbines. As Victoria et al. [3] show, the expansion of these energy storages in Europe increases with higher emission reduction targets. In this analysis we use an integrated energy system model to determine how much energy storage capacity is needed in a greenhouse gas-neutral German energy system and examine how hydrogen and heat storages provide flexibility for the energy system.

Methods

The integrated energy system model ETHOS.NESTOR [4] represents the entire German energy system and analyzes cost optimal transformation pathways to greenhouse gas-neutrality. This model depicts the sectors energy supply, industry, buildings and transport through an hourly resolved network of energy sources, conversion technologies, storages and energy demands. The resulting optimization problem is solved by minimizing the annual system costs with respect to the boundary constraints of the energy system. For example, all energy balances must be met in each hour of an optimization year. Furthermore, the energy system model uses a myopic back casting approach to analyze a cost-optimal transformation pathway from the current energy system to a future energy system [4]. The operation of the energy system model is driven by the energy demands of the sectors industry, buildings and transport, which are modelled through detailed process chains and are part of the cost-optimal optimization. Furthermore, the model uses renewable energy potentials for the installation of wind turbines and photovoltaic plants in Germany as input data, which are determined with the approach by Risch et al. [5]. The analyzed scenario has the legally binding emission reduction targets from the Federal Climate Change Act [1] as central boundary condition and is related to the study by Stolten et al. [2].

Results

Our optimization results show that in the year 2045 an installed capacity of about 449 GW of photovoltaic plants and about 285 GW of wind turbines are needed in Germany to supply a greenhouse gas-neutral energy system. As the security of supply must be guaranteed also during extreme events, we take a synthetic dark lull of two weeks in January into account in which only 10% of the capacity of wind turbines and photovoltaic plants is available for electricity generation. To overcome this period, about 86 GW of controllable power plants like hydrogen gas turbines and biomass power plants are required in the year 2045. Besides these power plants, long-term hydrogen storage is crucial for bridging dark lulls and balancing the seasonal variation of energy production from renewable sources. These hydrogen storages are filled during summer and are emptied during the winter months, especially during the dark lull in January (see Figure 1). Figure 1: Electricity generation and storage level of hydrogen storages in course of the year 2045. Based on study by Stolten et al. [2] In total about 35 TWh of long-term hydrogen storage capacity is needed in the year 2045. However, this storage capacity is only optimized for one specific weather year and does not consider that storages must be sufficiently large to balance variations in energy supply over several years. Applying a simulation of the operation of the hydrogen storages for 38 historical weather years leads to a necessary hydrogen storage capacity of about 70 TWh for a robust storage design. Heat storages provide flexibility both as seasonal and short-term storage for the energy system. For seasonal storage about 2.1 TWh of pit thermal energy storage capacity are installed in district heating grids. Furthermore, about 280 GWh of decentral heat buffer tanks enable a flexible operation of heat pumps in buildings, which in turn help to adjust the electricity demand to the volatile electricity generation by renewable energies.

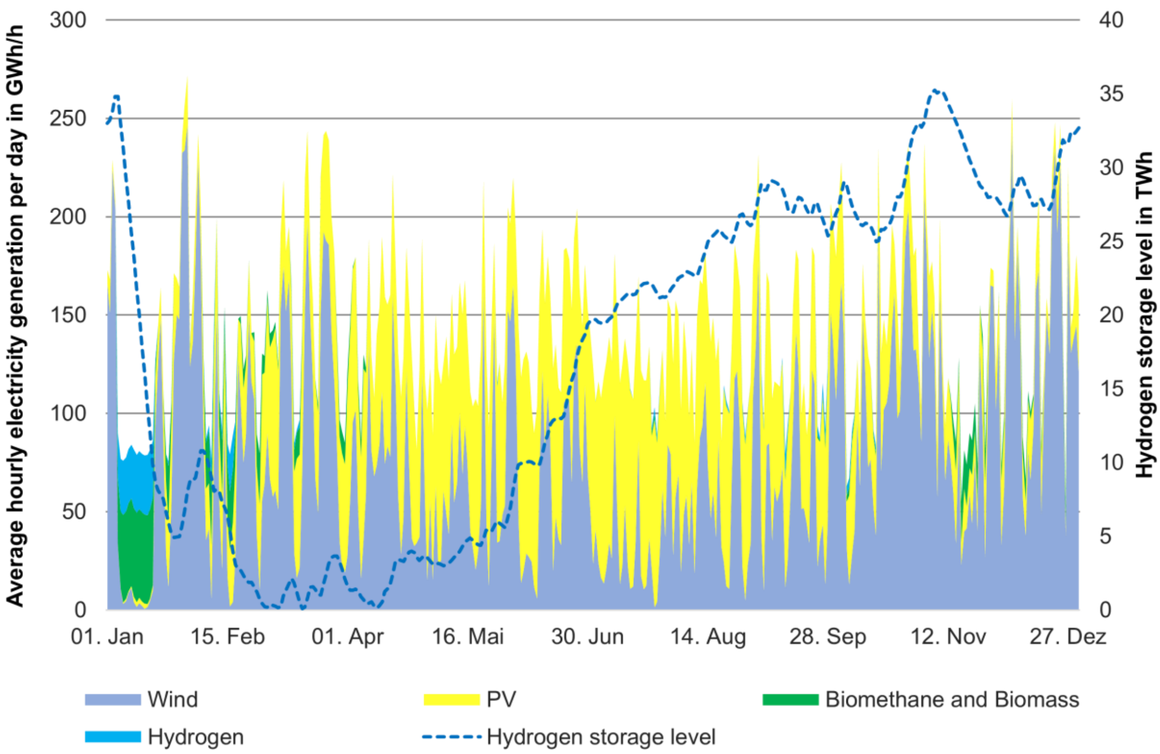

Figure 1

[1] *Federal Climate Change Act of 12 December 2019 (Federal Law Gazette I, p. 2513), as last amended by Article 1 of the Act of 18 August 2021 (Federal Law Gazette I, p. 3905).*

[2] *D. Stolten, P. Markewitz, T. Schöb et al., Neue Ziele auf alten Wegen? - Strategien für eine treibhausgasneutrale Energieversorgung bis zum Jahr 2045. Jülich: Schriften des Forschungszentrums Jülich, Reihe Energie & Umwelt, Band 577, 2022.*

[3] *M. Victoria, K. Zhu, T. Brown et al., The role of storage technologies throughout the decarbonisation of the sector-coupled European energy system, Energy Convers. Manag., vol. 201, p. 111977, Dec. 2019, doi: 10.1016/j.enconman.2019.111977.*

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[5] *S. Risch, R. Maier et al., Potentials of Renewable Energy Sources in Germany and the Influence of Land Use Datasets, Energies, vol. 15, no. 15, p. 5536, Jul. 2022, doi: 10.3390/en15155536.*

How much flexibility is needed by hydrogen power plants?

Philipp Hauser[1]

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Keywords: hydrogen, flexibility option, renewable energy integration, backup capacity, sector-coupling, energy system modeling

Motivation

The German government aims to achieve a carbon-neutral power system by 2035. This implies a power supply only based on renewable energy sources (RES). As wind and photovoltaic generation depend on weather conditions, flexibility is needed to balance supply and demand. In addition to storage technologies, like batteries, flexibility can also be provided by reactions on the demand side, e.g., power-to-heat, power-to-gas, electrical vehicles, or on the supply side due to dispatchable hydrogen power plants. Especially the latter is seen as the main flexibility option to provide firm backup capacity when the supply of fluctuating RES is insufficient. Against this backdrop, the overall question is how much capacity of gas power plants is needed in the future to ensure the security of supply for a carbon-neutral power system based on intermittent RES. Therefore, in this paper the impact of different flexibility options on the capacity needs for hydrogen power plants is analyzed based on a case study for 100% renewable power in Germany.

Methods

The methodological approach focuses first on a literature review on assumptions and applied approaches to describe carbon-neutral power markets. The focus is on the German power market and considers power-to-heat, battery electric vehicles and power-to-gas as flexible sector coupling technologies. Furthermore, flexible generation and demand is provided by pumped hydro storages, batteries and by modelling the power exchange with neighbouring countries through the transmission system. On the other side, flexible dispatch generation is depicted by biomass and hydrogen power plants. By using scenarios, different combinations of all flexibility options are analysed to assess the need of hydrogen power plant capacities. To quantify the results, the existing power market model ETRAMOD is used, and the scenario data is largely based on the network development plan that is provided by the German transmission system operators in their scenario framework.

Results

The results indicate that each flexibility option has a different impact on the capacity need for hydrogen power plants. In the model, each flexibility option on the demand side reduces the need of hydrogen power plant capacity in the order of magnitude from 15 to 22 GW compared to a case where no further flexibility options are added to the system. However, the individual impacts of each flexibility cannot be cumulated as they have an interplay. This portfolio effect can be derived from the model results. Therefore, one main conclusion is that sector coupling technologies and hydrogen power plant capacities must be considered jointly from an energy system perspective to prevent overcapacities but also the thread of underestimation of capacity needs. The model results indicate that at least a total capacity of 46 GW gas power plants is needed to achieve the carbon-neutral power system for Germany in 2035 even all of the discussed flexibility options are in place. The findings contribute to the ongoing discussion on the evolution of the new market design towards a carbon-neutral European electricity system. Results might be helpful for other researchers or decision makers on a national and European level.

Session 9:50 – 10:50
Renewables and modeling

Room: HSZ/0304
Chair: Hannes Hobbie

The insurance value of renewable energies

Thibault Deletombe, *Université Paris Dauphine-PSL*

A novel approach to generate bias-corrected regional wind infeed timeseries based on reanalysis data

Yannik Pflugfelder, *Universität Duisburg-Essen*

The effect of coarse weather data resolution on energy system model results

Matthias Zech, *DLR – Institut für vernetzte Energiesysteme*

The insurance value of renewable energies

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Keywords: electricity, renewable energy, power generation economics, economic value, risk preferences

Motivation

The 2022 gas crisis challenged the energy security of Europe. As a response, substantial investments occurred in the power system to strengthen its supply. However, governments still had to spend billions of euros in emergency packages to dampen inflation in the European electricity market. Moreover, some carbon-intensive technologies benefited from this period of high prices. Regarding energy transition and consumer protection concerns, public interventions in retrospect to the energy crisis led to mitigated results. In light of the recent events, this paper aims to investigate to which extent preemptive investments in additional power capacities effectively protect consumers against price risks and accelerate the energy transition. Much has been written on the stochastic capacity planning of the power system. However, a significant part of this literature focuses on the producer side and how uncertainty can reduce investments. Little is known about the consumer's willingness to pay for additional risk coverage and how it might affect the optimal capacity mix. This study proposes a new framework to evaluate the economic value of generating units in a context of uncertainty and analyse how consumers value protection against risks. This work emphasises on Variable Renewable Energies (VRE), namely solar and wind, to investigate if, in addition to their environmental benefits, they contribute to reduce supply risks despite their uncertain productions.

Methods

We define multiple states of the world with a fixed probability of occurrence and link them to a set of inputs for the power system (demand, load factors, energy prices, etc.). In each case, the electricity market sets consumer and producer surpluses over a year. To represent collective choices, we consider a risk-averse planner concerned about social surplus. This planner is rational and looks to maximize its expected utility. Under those assumptions, we show that the socially optimal willingness to pay of consumers for an additional capacity is an addition of two components. One translating the variation in expected surplus, and one translating the insurance value of the capacity, i.e., the variation of the risk premium associated with the lottery on the states of the world. Then, we perform numerical estimations to test this theoretical framework. We use a cost optimization model to simulate the French power system in 2030. Various states of the world are considered in order to emulate VRE intermittency and a gas price shock. We compute the insurance value of VRE regarding this shock and compare it to the ones of other technologies. Then, different VRE penetration rates are implemented until the optimal capacity mix when considering insurance value is reached.

Results

With the possibility of a gas shock similar to the one occurring in 2022 in Europe, the insurance value of VRE is positive. Under those circumstances, solar and wind energy acts as an insurance against uncertain events and consumers are willing to pay for it, which justifies ex-ante additional support for VRE. Considering the insurance value leads to an overall modification of the socially optimal capacity mix with a higher penetration of VRE.

A novel approach to generate bias-corrected regional wind infeed timeseries based on reanalysis data

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Keywords: wind power modelling, ERA5 reanalysis, bias-corrected wind power

Motivation

Climate mitigation targets foster a rapid expansion of wind energy. However, wind power supply is fluctuating and thus is not available at all periods of time, which has implications on power system operation and planning. Applying realistic wind speeds is important as this has noticeable implications on study outcomes. With increasing amounts of installed wind power capacity, the aspect of spatial distribution and corresponding variability is getting more important. The generation of wind power supply timeseries is strongly dependent on data availability. Wind speed measurements on hub height levels are barely accessible and the measurement data are not representative for different landscapes. Given the lack of measurement data, reanalysis weather models are often used as basis for wind power timeseries generation. These models provide atmospheric data in a consistent format. One shortcoming is particularly the limited representation of local topography, consisting of orography, roughness, and obstacles. This has implications in the lower atmospheric boundary layer where friction is not neglectable. One approach to reduce erroneous wind infeed simulation is bias correction. It is commonly performed to correct for deviations in energy quantities between simulated values and measured data. To the best knowledge of the authors, bias-correction on annual energy quantities at turbine level has not been attempted so far. This work thus addresses the subsequent research hypothesis: (i) Does local bias correction improve the results of technical bottom-up simulations using reanalysis data? (ii) Which local information is relevant to describe the annual energy offset between simulated figures based on reanalysis data and local measurements? (iii) To what extent can time-independent local bias correction factors be generally used in different weather years?

Methods

A bottom-up simulation for wind power infeed was performed followed by an identification of local factors that may explain regional deviations from the reanalysis-based simulated data have and these have been used as predictors in a regression model. Data used for simulation include net power rating, hub height, rotor diameter its coordinates, wind speeds and assumptions on technical availability, wind speed dependent wake effects, curtailment and unavailability. Relevant local aspects that cause a deviation between measured wind infeed and simulated data based on reanalysis model data are identified and we propose local factors for correction: height above sea level, hilliness of the surroundings, distance to the sea, amount of wind turbines nearby and turbine specifications (hub height, rotor diameter, net power rating). With knowledge on yearly measured energy infeed of turbines, the full load hour of each turbine can be adjusted to better match measured quantities. Abstaining from hourly information, the annual error in full load hours is a key value to depict the offset. To estimate this offset in full load hours between the simulated and the measured data in the target year based on local information with regressors that account for regional influences, we make use of a linear multiple regression with heteroscedastic and autocorrelation consistent covariance estimators to obtain the estimates with their corresponding standard errors. This estimator is chosen, as the ordinary least square estimator would require a standard normal distribution of residuals. After parametrizing the model using the observations for the base year, the offset for each location in the target year may be calculated. The local bias-corrected simulation production thus consists of the simulated time series corrected by the full load hour offset. For verification of the results, we compare the deviations in FLH in the simulated model and the deviations in the corrected model.

Results

The regression estimates are determined for the three base years 2016, 2020 and 2021. The estimation results and the values for the R2 and root mean square error (RMSE) are similar over all three models (cf. Table 1). The 2021 data fit best with an R2 of 0.271 and an RMSE of 321. The parameter estimates of the models lie all within the same order of magnitude. The values for the predictors distance to sea and net power rating differ slightly between the observed years, while rotor diameter and hilliness of the surroundings show a higher deviation. With the base year regression estimates, the deviation in the target year can be estimated for each turbine. Therefore, the simulated infeed is corrected by this estimated FLH deviation. Error terms describe the percentage deviation between the bias corrected production and the observed value and between the modelled production without correction and the observed value. The error improvement states the relative improvement of the corrected simulation model in comparison to the original simulation. An application of the bias-correction based on local indicators reduces the error of the reanalysis-based output simulation (71.3 % in 2020, 93.1 % in 2021). It can be observed that the number of large overestimations is reduced. The unsystematic pattern after local bias correction indicates that there is no structural bias after applying the model. The FLH deviations between the simulated and reported wind energy production of 2020 are aggregated on NUTS 3 (Fig. 1). Applying the correction method leads to an error reduction in most of the 304 regions with installed wind turbines. Great improvements are achieved in the northern regions with many installed turbines. Good improvements are observed in most regions of central Germany. In some southern regions, our model leads to an increase in the observed deviation, although in most cases this occurs in areas with low total output. The error reduction over all regions is 71.3 %.

Table 1: Regression estimates for 2016, 2020 and 2021.

	2016 ERA5		2020 ERA5		2021 ERA5	
	Estimate	tStat	Estimate	tStat	Estimate	tStat
Intercept (β_0)	789.977	12.726 ***	886.817	14.265 ***	786.948	14.689 ***
Height above sea	0.792	7.009 ***	0.446	4.503 ***	0.565	6.890 ***
Hilliness of the surroundings	-75.938	-5.115 ***	-37.051	-2.866 **	-44.673	-3.953 ***
Distance to sea	-1.692	-14.339 ***	-1.536	-14.355 ***	-1.414	-15.891 ***
Amount of turbines around	0.691	2.173 **	1.010	3.673 ***	1.137	4.586 ***
Hub height	-1.347	-3.048 **	-1.714	-4.328 ***	-2.007	-5.750 ***
Rotor diameter	-1.674	-1.699	-2.907	-3.790 ***	-2.212	-3.419 ***
Net power rating	0.104	4.727 **	0.102	5.359 ***	0.094	5.538 ***
R^2	0.271		0.251		0.271	
RMSE	348		372		321	

* p<0.05, ** p<0.01, *** p<0.001

Table 1

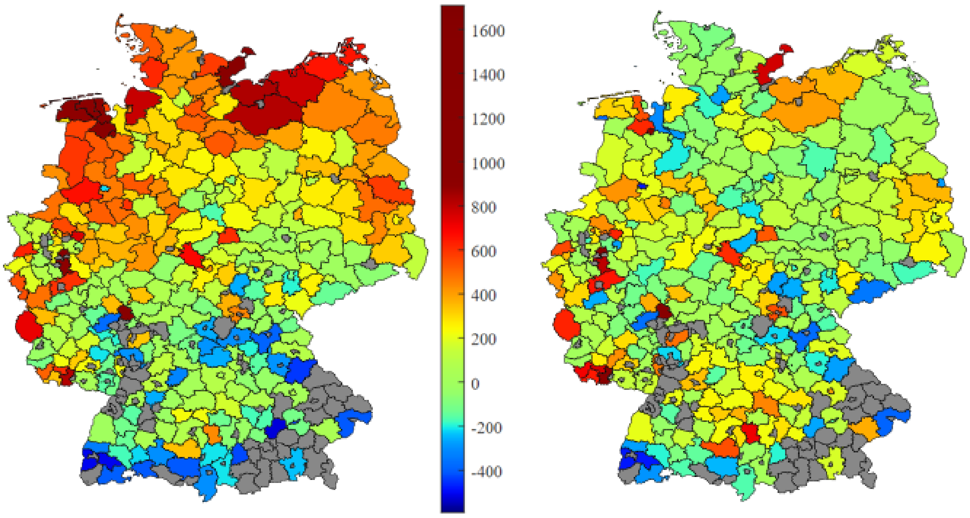

Figure 1.1: FLH deviation of simulated wind energy production 2020 ($\Delta FLH^{simulated}$) per NUTS 3

Figure 1.2: FLH deviation of the corrected simulations 2020 with base year 2016 ($\Delta FLH_{2016,2020}$) per NUTS 3

Figure 1

The effect of coarse weather data resolution on energy system model results

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Keywords: energy meteorology, spatial granularity, renewable energy, energy economics

Motivation

Energy system models have become an extensively used tool to support energy policy decision-makers for a wide range of tasks such as to derive carbon-neutral expansion plans of sustainable energy systems, to design more more resilient energy systems or to calculate the optimal power flow under techno-economical constraints. With larger shares of renewable energy in energy systems and thus larger weather-dependent energy feed-ins, the importance of weather data quality increases. This also reflects in the increasing number of publications about the sensitivity of energy systems to weather and climate data. A thorough analysis of the effect of spatial resolution on energy system model results is however still lacking.

Methods

This study aims at closing this gap by using a high resolution regional reanalysis model with a 6 km spatial resolution (COSMO REA6) which is then artificially averaged to lower spatial resolutions. Decreasing the spatial resolution of the meteorological data has the advantage that the effect of lower data resolution on all subsequent stages, when used within energy system models, can be studied. We therefore investigate the impact on the meteorological data, the capacity factors and on the energy system model results. In the latter, we focus on the impact on the residual load, the curtailment and the electricity prices. The used energy system model is the PyPSA-based eTraGo model with a coverage of Germany.

Results

The results of this study show that the impact of using lower weather data resolution on meteorological data is two-fold. First, there is an inherent bias of the meteorological values induced by lower spatial resolutions with different patterns subject to the respective topography. Second, variability is reduced due to using less information which makes the renewable energy sites more equal. We show that these properties make the energy system model results less favorable comparable to the native resolution. This study therefore not only shows that there is an impact of using lower weather resolutions, but also warns that simple weather data resolution makes sustainable energy systems less attractive.

Session 11:15 – 12:15
Energy system modeling II

Room: HSZ/0004, hybrid
Chair: Felix Jakob Fliegner

Investments in coupled energy sectors and market pricing
Johannes Wirth, *FAU Erlangen-Nürnberg*

Energy imports and infrastructure in a climate-neutral European energy system
Fabian Neumann, *Technische Universität Berlin*

Green deal and carbon neutrality assessment of Czechia
Lukáš Rečka, *Charles University Praha*

Investments in coupled energy sectors and market pricing

Johannes Wirth[1]

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Keywords: market coupling, uncertainty, investments, optimization

Motivation

The low-carbon transition of the energy system is important to reach the goal of climate neutrality in Europe until the year 2050. With increasing levels of renewable electricity generation, the concept of sector coupling is gaining more and more attention in energy-economic research and policy discussions. The complete decarbonization of the energy sector will lead to renewable electricity substituting fossil energy carriers in the heat and mobility sectors, either directly or as input to produce sustainable synthetic fuels like hydrogen and its derivatives. These green energy carriers are broadly promoted to decarbonize especially emission-intensive industry applications, certain types of mobility, and backup power generation which cannot be electrified easily. At the same time, markets for hydrogen-based energy carriers will emerge at regional and global level to supply feedstock demand for industries and a sustainable fuel for energetic use. This transition will result in coupled electricity and hydrogen markets at a regional level.

Methods

To obtain a better understanding on such coupled markets, we develop a model with an hourly spot-market which couples markets, i.e. bidding zones for supply and demand of electricity and hydrogen. At the current state, we assume fixed trade capacity between bidding zones of one energy carrier but allow for private firms to decide on their investment in conversion, generation, and storage capacities anticipating their spot-market revenues. In our definition, generation technologies produce electricity or hydrogen relying on an energy input, which is not part of the model scope, at a fixed fuel price, i.e. they do not couple the electricity and hydrogen markets. All other technologies provide some sort of market coupling, i.e., conversion technologies between electricity and hydrogen markets, storage installations allow for inter-temporal coupling of supply and demand in one bidding zone, and trade technologies provide spatial market coupling between bidding zones. All technologies participate on the spot-market. In our paper, we analyze the effect of uncertainty regarding climatic years as well as anticipated technology pathways for a case study on a defossilized German energy system in 2040. To do so, we compare investment results in consideration of only one reference climate year to those in consideration of multiple climate years. Therefore, the sum of the total welfare of all considered years is maximized. To picture uncertain climate conditions, the underlying optimal investments have to hold for all considered years, while their operation can differ. In a second step, the effects of deviating investment cost pathways for batteries and electrolyzers are analyzed.

Results

Our results show that uncertain climatic conditions increase investments in solar PV and wind installations, reducing the need for re-electrification via hydrogen turbines. Analyzing expensive electrolyzers in a 2040 world, e.g. driven by material scarcities, leads to higher deployments of batteries, while, vice versa, increasing battery costs lead to a substitution of battery capacity with hydrogen storage in combination with higher electrolysis investments.

Energy imports and infrastructure in a climate-neutral European energy system

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Keywords: energy imports, energy infrastructure, net-zero, e-fuels, e-materials

Motivation

The transformation of the European energy system towards climate-neutrality demands unrivalled technological change. Whereas the development of renewables energy sources in Europe and supporting measures like reinforcing the electricity grid do not always meet the level of acceptance required for a swift transition, other parts of the world have cheap and abundant renewable energy supply potentials to offer to global energy markets. However, even if economically attractive, a strong dependence on energy imports can be detrimental to energy security. Risks must be weighed against the potential benefits of decreasing energy supply costs, reducing land usage and increasing energy security by supplying storable fuels that can mitigate energy droughts for systems with high shares weather-dependent energy supply. Here, we explore the full range between the two poles of full self-sufficiency and wide-ranging energy imports into Europe in scenarios with high shares of wind and solar electricity and net-zero carbon emissions. We investigate how the infrastructure requirements of a self-sufficent European energy system that exclusively leverages local resources from the continent may differ from a system that relies on energy imports from outside of Europe. We integrate a model of global energy supply chains by Hampp et al. (2023) with a sector-coupled energy system model, PyPSA-Eur-Sec, to investigate the impact of imports on European energy infrastructure needs. We evaluate potential import locations and carriers, the economic impetus for such imports, and how their inclusion affects deployed transport networks and storage. As possible import options we consider imports of electricity, hydrogen, methane, ammonia, methanol, steel/iron sponge and Fischer-Tropsch fuels. Moreover, we compute scenarios where only a subset of carriers can be imported to assess how the different import scenarios affect the energy infrastructure inside Europe.

Methods

We use the open European energy system model PyPSA-Eur-Sec, that combines a fully sector-coupled approach with high spatial and temporal resolution and detailed transmission infrastructure representation. The model co-optimises the investment and operation of generation, storage, conversion and transmission infrastructures in a single linear optimisation problem. It covers 128 individual regions and uses a 3-hourly time resolution for a year. Thereby, the model is detailed enough to capture existing grid bottlenecks, the variability of renewables and seasonal storage. It includes regional demands from the electricity, industry, buildings, agriculture and transport sectors, including shipping and aviation as well as non-energy feedstock demands in the chemicals industry. Furthermore, it covers transmission infrastructure for electricity, gas and hydrogen as well as candidate entry points for energy imports like existing and prospective LNG terminals and cross-continental pipelines. We enforce net-zero emissions for CO2, allow a doubling of today's power grid infrastructure, take technology and assumptions for the year 2030, and limit the carbon sequestration potential to 200Mt CO2 per year. Fuel import costs are based on Hampp et al., who assessed the cost importing various energy carriers across different global green energy supply chains from various regions of the world. We use these supply curves to determine for each energy carrier and model entry point the region-specific lowest import cost, thus, incoporating the potential trade-off between import cost and import location. Our selection of exporting countries comprises Australia, Argentina, Chile, Kazakhstan, Turkey, Ukraine, the United States and Canada, China, and the MENA region. The hydrogen import costs are lower where they can be imported via pipeline rather than by ship. The imports of ammonia and liquid hydrocarbons are not spatially resolved. Electricity imports are endogenously optimised.

Results

We find that allowing energy imports from outside of Europe reduces total energy system costs by up to 7%. In this case, around 30% of the system cost would be spent on energy imports. But the cost reductions depend on the available import options. Our preliminary results indicate that half of the cost reductions can be achieved with exclusive hydrogen imports, whereas 70% of the reduction (for a total reduction of 5%) can be achieved with exclusive electricity imports. If the carrier mix for energy imports can be flexibly chosen, we find a cost-optimal import volume of 3750 TWh (a third total final energy demand). Roughly 59% is imported in the form of electricity. Another 39% are imported as hydrogen. A large share of power-to-hydrogen production is outsourced from Europe. We find that half of the 7% cost benefit can be achieved with imports below 1000 TWh (a quarter of cost-optimal import volumes). Results also show that the solution space is flat in a wide range between imports of 0 and 8000 TWh. Importing around 7500 TWh is just as expensive as the scenario without any imports. Allowing imports of electricity, green e-fuels alters the infrastructure buildout in Europe. With fully self-sufficient European energy supply, we see large PtX production within the European periphery to cover the demand for hydrogen derivatives in steelmaking, high-value chemicals, as well as shipping and aviation fuels. Electricity grid reinforcements are mostly focused in Northwestern Europe. However, the import of electricity and hydrogen displaces much of the European PtX production capacities and diverts some of the electricity grid reinforcements to Southern Europe. Increased energy imports change the hydrogen network's role to transporting imports from North Africa rather than distributing hydrogen from the North Sea area.

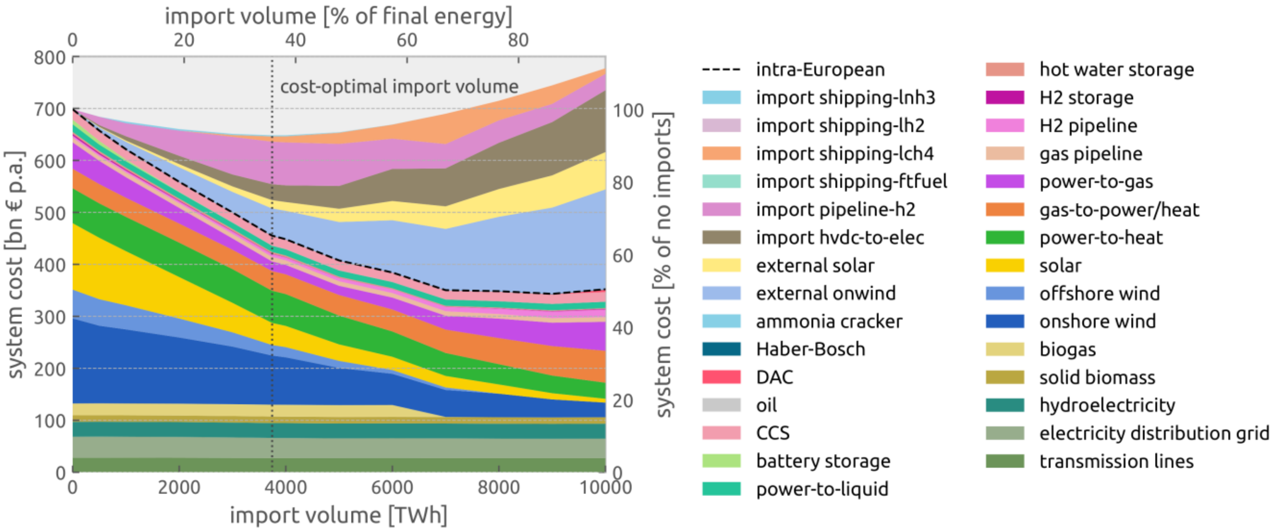

Figure 1

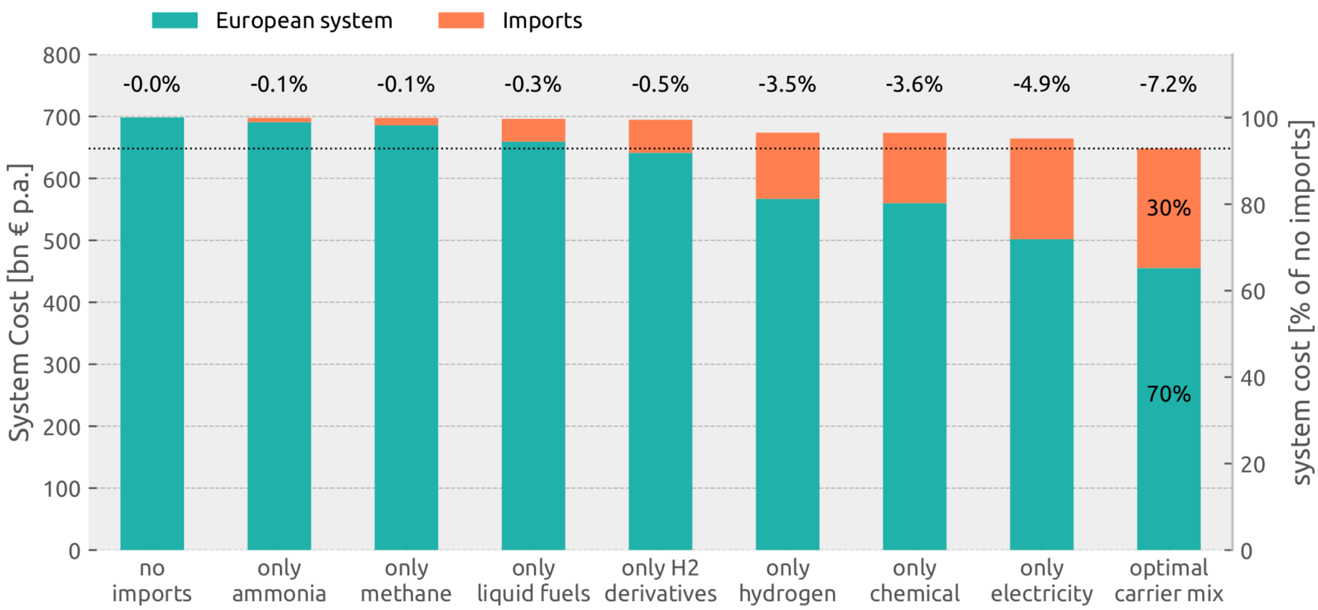

Figure 2

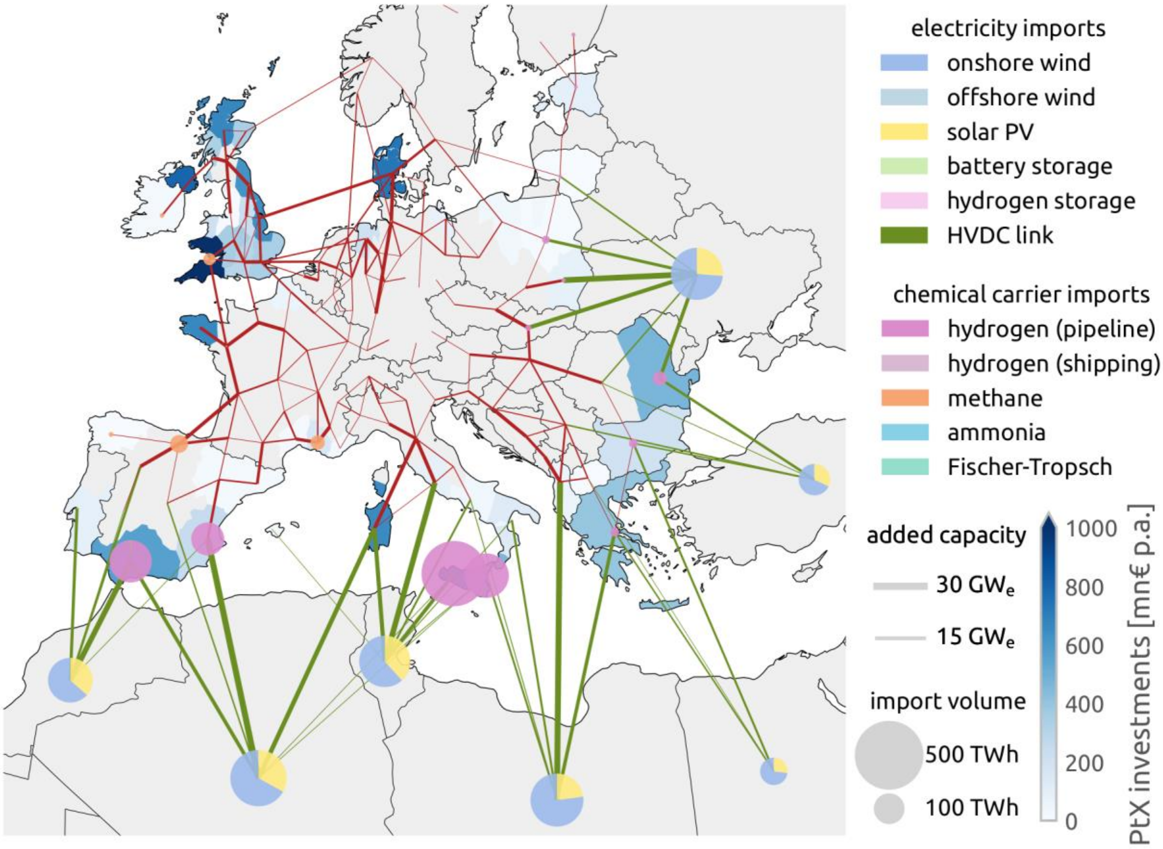
electricity imports
onshore wind
offshore wind
solar PV
battery storage
hydrogen storage
HVDC link
chemical carrier imports
hydrogen (pipeline)
hydrogen (shipping)
methane
ammonia
Fischer-Tropsch
added capacity
30 GWe
15 GWe
import volume
500 TWh
100 TWh
1000
800
600
400
200
0
PtX investments [mn€ p.a.]

Figure 3

Green deal and carbon neutrality assessment of Czechia

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Keywords: green deal, GHG emissions, climate neutrality, EU ETS, TIMES-CZ

Motivation

The European Green Deal aims to achieve climate neutrality by 2050 and sets a binding EU target of a 55% reduction in greenhouse gas (GHG) emissions by 2030 compared to 1990 level. The Fit for 55 package, which includes a series of legislative initiatives across a range of sectors to put the EU on track to meet its 2030 climate target of 55%, got close to its final approval during 2022. The EU-wide impact assessment of the Climate Target Plan preceding Fit for 55 package and the subsequent 'core policy scenarios' with Member State-level details have been followed by other studies. While Pietzcker et al. (2021) focus only on the EU Emissions Trading System (EU ETS) sectors, Kattelmann et al. (2021) analyze the optimal share of GHG emission reductions between EU ETS and Effort Sharing Regulation (ESR) sectors and the optimal GHG emission reductions in ESR sectors for each EU Member State. Other studies assess the impacts of the Fit for 55 package on a specific sector or on one sector or more sectors in a single country.
The paper aims to enrich the literature by a case study of Czechia. Czechia had significantly reduced its greenhouse gas emissions during the 1990s but remains one of the two most industrialized EU member states with the third highest GHG emissions per capita, high energy intensity of industry, and relatively lukewarm attitude towards climate change mitigation measures. So far, there is one study that evaluates the 55% reduction of GHG emissions by 2030 and climate neutrality by 2050 in Czechia, which does not evaluate any policy but searches for a suitable way of Czech decarbonization. We apply the energy optimization model TIMES-CZ to analyze the impacts of the extension of the EU ETS to buildings and road transport (EU ETS 2) and of a coal phase-out on the Czech energy system. We also assess the capability of Czechia to achieve climate neutrality by 2050 without biomass or hydrogen imports.

Methods

TIMES-CZ is a technology-rich, bottom-up, cost-optimizing integrated assessment model built within the generic and flexible TIMES model generator's GAMS code. TIMES searches for an optimal solution for an overall energy mix that will satisfy exogenously given energy service demand with the least total discounted costs in a given timeframe with a perfect foresight principle. The TIMES-

CZ model covers the entire energy balance of Czechia from the supply of resources to the energy service demand. The structure of the TIMES-CZ model is significantly extended in four ways. First, all EU ETS sectors are disaggregated into individual units. The non-ETS parts correspond to the structure of the TIMES-PanEu model. Based on data from EU ETS emission reports, unique multi-fuel mixes are created for each ETS source according to their actual consumption. Other input data for the individual EU ETS sources are obtained from the Register of Emission and Air Pollution Sources and from the Energy Regulatory Office. Second, the emissions trading mechanism takes into account the transition to auction-ing and the derogation (free allowances for existing power plants for a transitional period until 2019 according to Article 10c of the EU ETS Directive). Third, both district heating demand and supply are regionalized into 36 regions based on zip codes. Forth, a detailed transport module is developed. In the base year, the transport module contains 135 technologies for road vehicles by COPERT categories (i.e. distinguishing vehicle category and type, fuel, and EURO norm). Transport technologies for future years include both new and second-hand vehicles. The module includes biofuel production. We define a baseline scenario, called NECP, derived from the National Energy and Climate Plan,), and three policy scenarios to assess impacts of the extension of the EU ETS to buildings and transport (EU ETS 2) and of coal phase-out on the Czech energy system.

Results

Our modeling shows that achieving 55% reduction in Czech total GHG emissions by 2030 is realistic, mainly due to emission reductions in the EU ETS sectors. Only the NECP and NECP_zero scenarios fail to meet the 2030 target due to positive GHG emissions from LULUCF. However, based on the results of other scenarios and other studies, higher prices for EUAs or fossil fuels – which Europe has been facing since the post-COVID recovery – might lead to further GHG emissions reduction. On the other hand, the pace of GHG emission reductions in the non-ETS sectors is slow in all scenarios, which is also due to the increasing demand for energy services. In 2030, GHG emissions in the ESR sectors are reduced by 15 (REG) to 22% (NECP and NECP_zero) compared to 2005. In contrast, climate neutrality is not achieved in any scenario by 2050, and 10 Mt CO2ek remains in the NECP_zero and REG scenarios even when accounting for emission sinks from LULUCF and CCS. There are several reasons for it, primarily stemming from model-ling assumptions. 1) all scenarios assume national self-sufficiency in renewables, hydrogen production, and electricity generation; and the modeling results clearly shows how restricting these assumptions are, especially for decarbonization of industry. 2) two sectors with non-negligible GHG emissions, agriculture and waste, are not directly modeled and the emission trajectories used for them are not in line with ambitious climate policies that will strive for deeper uptake of circularity principles and waste hierarchy, progressive uptake of GHG abatement practices in livestock and farming practices as well as profound dietary changes in the population. 3) the imposed maximum potentials of solar and wind are rather conservative and can be overcome with the deployment of more advanced technologies and better coordination. 4) the assumptions about the costs of emissions allowances and fossil fuels represent an outlook prior to the Russian aggression on Ukraine.

Session 11:15 – 12:15
Natural gas II

Room: HSZ/0401, hybrid
Chair: Maximilian Happach

Long-term development of European natural gas markets - Scenario analysis using the global gas model (GGM) (online)

Lukas Barner, *Technische Universität Berlin*

Could we learn from our mistakes in the past? Comparing gas market forecasts from MAGELAN model with actual developments in reality

Andreas Seeliger, *Hochschule Niederrhein*

Expanding natural gas cross-border flows in europe through the optimal use of the pipeline grid: A stylized model comparison

Christian von Hirschhausen, *Technische Universität Berlin*

Long-term development of European natural gas markets - Scenario analysis using the global gas model (GGM) (online)

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Keywords: Natural gas, Europe, energy crisis, prices, LNG

Motivation

The massive reduction of Russian natural gas exports to Europe following the invasion of Ukraine in February 2022 has led to a significant reshuffling of gas flows in Europe and – via international trade of liquefied natural gas (LNG) – beyond. In the shortterm, supply security in Europe was maintained through a significant increase of other pipeline deliveries, and additional LNG imports, mainly through Belgium and the Netherlands (McWilliams et al. 2023). Planned outages could be avoided and overall, and the risk of serious short term supply gaps for the next winters appears manageable (Holz et al. 2023, 2022; Höhne, Marquardt, and Fekete 2022). However, longer-term natural gas markets in Europe are subject to substantial uncertainty, not only on the supply side but also on the demand side, where the future role of natural gas is challenged by climate considerations and electrification. The paper provides a model-based analysis of potential developments of European gas markets in the context of global natural gas trends, including both geopolitical developments and climate policy considerations.

Methods

The model applies a numerical partial equilibrium model of the global natural gas market, the "Global Gas Model" (GGM), to a set of scenarios defined by the authors. The Global Gas Model is a multi-period partial equilibrium model for analyzing the world natural gas market along the value chain from production wells to final consumers; market agents include suppliers, transmission system (TSO) and storage operators (SSO) (Figure 1) (https://www.ntnu.edu/iot/energy/energy-models-hub/ggm). The GGM has a detailed representation of the European natural gas pipelines and LNG-terminals and has been applied to similar model-based analyses, such as in (Egging et al. 2009; Egging and Holz 2016; Holz et al. 2017; Egging, Holz, and Czempinski 2021). The paper first presents a calibration of the status quo of European and international gas markets before the run-up of the war, i.e., the "status quo ante bellum", based on previous model exercises and some updating of the data. The paper then proceeds with a 2x2-matrix of scenarios, covering both the supply side and the demand side (Table 1). On the demand side, we take scenarios inspired by two projections from the IEA's World Energy Outlook (IEA 2021, 2022): The Stated Policies Scenario (STEPS) of 2021, and the Announced Pledges Scenario (APS) of 2022 (if possible, we will extend the model by a "Net Zero Emissions by 2050" scenario (NZE)). On the supply side, scenarios vary with respect to trade between Russia and Europe, one without natural gas trade altogether ("New normal"), and another one with a gradual re-establishment of trade flows, albeit at a lower level than before ("gradual recovery").

Results

At present, an update of the model data for existing infrastructure in 2020 is under way, as is calibration of supply and demand projections to the STEPS and APS scenarios. First exploratory scenario runs are carried out. While the model covers global trends, the focus of the results will be the impact on European natural gas markets in the four scenarios, until 2050, in terms of quantities, net import balances, and the role of international LNG trade. Europe has plenty regasification capacity, but LNG supply will be rather tight for several years, and an uptake of Chinese demand post-covid could put upward pressure on LNG prices. The paper will also put these results in perspective with other ongoing papers on the topic, and compare them to previous scenarios in the literature before the supply interruptions from Russia (e.g. Hauser 2021). The paper provides insights into an important recent issue, i.e. the development of European natural gas markets following the Russian invasion of Ukraine and the plans laid out in REpowerEU to become independent from Russian fossil fuel supply well before 2030, and reduce fossil fuel consumption in the EU significantly. Expected results should provide valuable insights into future developments for both academics, as well as practitioners and policy makers.

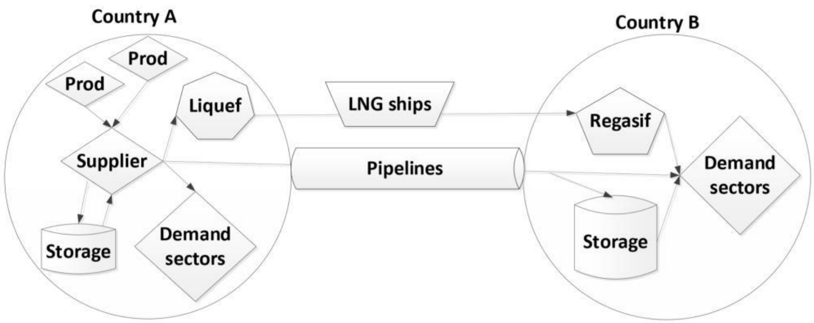

Figure 1: Representation of the Global Gas Model (GGM)

Could we learn from our mistakes in the past? Comparing gas market forecasts from MAGELAN model with actual developments in reality

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Keywords: modelling, gas market, LNG, shale gas, security of supply

Motivation

Natural gas investments are characterised by high costs and very long life times of some infrastructure elements, such as pipelines or LNG plants. Given this long-term character of gas investments, forecasting of future developments is an essential need for all players in the gas market. Ideally, those forecasts are based on well-designed, detailed and transparent models. From investors perspective, bottom-up respectively so-called fundamental models which are based on specific infrastructure elements, provide more helpful information compared to top-down models with rather gross aggregation levels. As investors, policy makers and also researchers have a need of reliable model results, models should be faced with reality from time to time. This is obviously easier for short-term models, e.g. forecasting day-ahead prices. Given the long time periods between date of modelling and years to be forecasted (in some cases up to 50 years or more), such reality checks are not as common as in more shorter-term models. Nevertheless, some reviews are undertaken, e.g. oil production and peak oil forecasts. This paper presents a reality check for the global gas market model MAGELAN. This model was developed in 2005 at the Institute of Energy Economics at University of Cologne. MAGELAN is a powerful tool which helps to analyse global gas markets and to forecast their development over the next decades. Consequently, the model was used in various projects for energy companies or policymakers. The paper starts with a comprehensive overview of the model structure, followed by a reality check which compares actual data for 2020 with forecasted values for this year more than 15 years ago. The paper finish with a brief discussion of some of the differences between reality and model results. Finally,some thoughts are given, if some obvious mistakes are made in the modelling process and how some of the divergence could be avoided in future model versions.

Methods

MAGELAN is a linear optimisation model, using GAMS as programming language and CPLEX as solver. Figure 1 provides an overview over the most relevant model input and output data. Actual data is taken from various sources, such as BGR (2022), BP (2022) and IGU (2021). In this paper, some of the most interesting data (e.g. production volumes, LNG and pipeline investments, net-exports) will be discussed in detail.

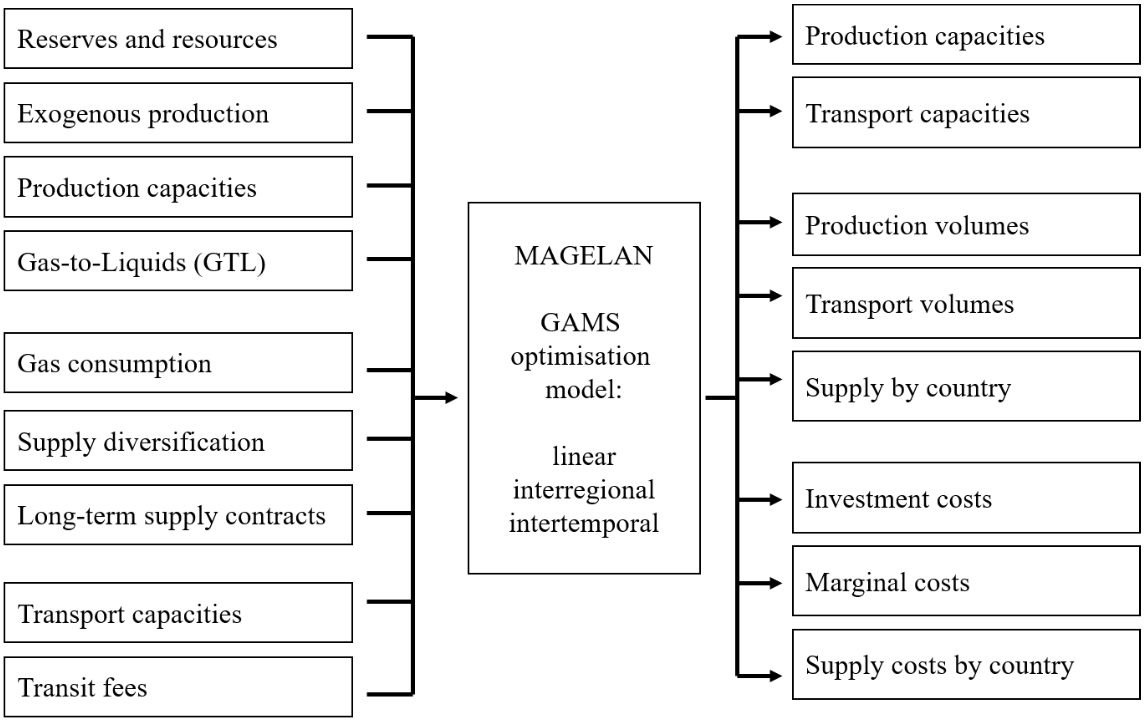

Figure 1

Results

Some forecasts show a very high accordance with actual figures (such as aggregated global gas production or total LNG trades), some other are far from recent developments in the real world (e.g. gas production of individual countries or realised capacities of specific pipeline projects). Table 1 shows some exemplarily figures for global net-exports. As one could see, the overall net-exports forecasted by the model come quite close to actual data, but some discrepancies exist for individual countries. Some major exporters in reality were heavily underestimated (such as Australia or the USA), whereas for other players reality lacks massively behind the model (especially Iran and Venezuela). In the paper, these discrepancies will be discussed. Some of the discrepancies might have been avoided (and could be avoided in future model versions) with some model improvements, but other divergences derive from political developments (Iran, Venezuela) or technical progress (shale gas in the USA), which reasonably couldn't have been fully anticipated back in 2006.

		Reality 2004	MAGELAN 2020	Reality 2020	Difference 2020
1	Qatar	24	91	104	-13
2	Iran	0	55	0	55
3	Indonesia	34	44	20	24
4	Venezuela	0	37	0	37
5	Nigeria	13	36	28	8
6	Algeria	26	29	14	15
7	Malaysia	28	29	32	-3
8	Australia	12	19	105	-86
9	Trinidad & Tobago	14	19	14	5
10	Egypt	0	17	2	15
11	United Arabic Emirates	7	16	8	8
12	Russia	0	12	40	-28
13	Oman	9	12	11	1
14	Brunei	10	9	8	1
15	Bolivia	0	8	0	8
16	Yemen	0	8	0	8
17	Libya	1	7	0	7
18	Norway	0	6	4	2
19	Equatorial Guinea	0	5	4	1
20	USA	2	3	60	-57
21	Peru	0	2	5	-3
22	Angola	0	0	6	-6
23	Cameroon	0	-	1	-1
24	Papua New Guinea	0	-	11	-11
	World	180	464	479	-15

Table 1

Expanding natural gas cross-border flows in europe through the optimal use of the pipeline grid: A stylized model comparison

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Keywords: natural gas, pipelines, Europe, modelling, efficiency

Motivation

The energy crisis in Europe in the wake of the Russian war in Ukraine has once again highlighted the importance of trans-boundary grid infrastructure for flexibility and supply security. Thus, within several months, the large-scale disruption of natural gas flows from Russia to Europe had to be mitigated by pipeline flows from different direction within Europe, and liquefied natural gas (LNG) imports from overseas. However, the European gas grid has also shown signs of congestion, which have limited the flexibility of exchange and reduced supply security. One instrument that can be applied to relieve the situation is to optimize the bilateral flows in cross-border pipelines. At present, the optimal use of the pipelines is constrained by negotiated caps on the flows. Concretely, the maximal flows between country A and country B are differentiated, so that the maximum pipeline flow in one direction, say from A to B (fmax A to B) is different from the maximal flow in the inverse direction, i.e. B to A (fmax B to A). This is the case, for example, for flows between Germany and the Czech Republic (fmax G to CZ = 95,9 billion cubic meter (bcm), whereas fmax CZ to G = 38,5 bcm), between France and Belgium (fmax F to B = 21,3 bcm, fmax B to F = 30,3 bcm), or between the Netherlands and Germany (fmax NL to G = 65,0 bcm, fmax G to NL = 32,5 bcm). The capacities are negotiated between the countries and their respective network operators. From an energy economic perspective, the optimal use of these capacities would suggest symmetry, assuming that the technical conditions for bi-lateral flows are given, or can be established at low costs.

Methods

We calculate the effect of an optimal utilization of the existing natural gas grid in two models, the "Global Gas Model" and the Global Energy System Model ("GENeSYS-MOD"), and then proceed with a model comparison between the two:

• The Global Gas Model (GGM) is a multi-period equilibrium model for analyzing the world natural gas market along the value chain from production wells to final consumers; market agents include producers, traders, transmission system (TSO) and storage operators (SSO). The TSO manages the pipeline network as well as the LNG liquefaction and regasification terminals. The GGM has a detailed representation of the European natural gas pipelines, and therefore can be used to estimate the potential effects of an optimal use of capacity (Figure). The model has been previously used to simulate European and global scenarios, such as (Holz et al. 2017; Egging, Holz, and Czempinski 2021).

• GENeSYS-MOD, the Global Energy System Model, is an open-source energy system modeling framework. The model endogenously determines cost optimal investment paths into conventional and renewable energy generation, different storage technologies, and some infrastructure investments in five-year steps until 2050 (Figure). GENeSYS-MOD has also been applied to issues of the European energy market restructuring, including natural gas, such as (Hainsch et al. 2018; Auer et al. 2020; Hainsch et al. 2021). The theory of optimal pipeline utilization has been discussed in a variety of papers and studies, such as (Cremer, Gasmi, and Laffont 2003). It corresponds to theories on "nodal pricing" that has been applied in theory and in practice in the electricity sector (Hogan 1992; Stoft 2002, Chapter 4; Neuhoff et al. 2013) and, more generally, optimal use of infrastructure.

Results

At this point, test runs are carried out with both models. For the paper, both models will perform baseline runs for 2020 and 2025, with and without capacity restrictions on cross-border flows. This will provide an indication of the importance of the optimal use of capacity in these years, in terms of flows and prices. In addition, a scenario run for the case of the 2022 energy crisis including Russian supply disruption is carried out: How much would an optimal use of natural gas pipeline grids have contributed to relieving the energy crisis in 2022 (Kotek et al. 2023)? The paper also contains a discussion of the institutional aspects of pipeline regulation as well as a discussion of investment requirements in the EU pipeline grid.

Session 11:15 – 12:15
Hydrogen and infrastructure

Room: HSZ/0301
Chair: Lauritz Bühler

A sector-coupled european energy system towards 2050 - Exploring the role of hydrogen pipeline infrastructure

Jonathan Hanto, *Europa-Universität Flensburg / TU Berlin*

Generation options & effects of sustainable hydrogen from offshore wind energy on the German energy system

Enno Wiebrow, *Technische Universität Berlin*

The economics of global green ammonia trade – "Shipping Australian wind and sunshine to Germany"

Kiana Niazmand, *FAU Erlangen-Nürnberg*

A sector-coupled european energy system towards 2050 - Exploring the role of hydrogen pipeline infrastructure

Jonathan Hanto[1]

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Keywords: energy infrastructure, hydrogen, energy system modeling, energy economics, GENeSYS-MOD

Motivation

With the aim of reducing carbon emissions and seeking independence from Russian gas in the wake of the conflict in Ukraine, the use of hydrogen in the European Union is expected to rise in the future. As a clean and versatile energy carrier, renewable hydrogen can be produced from a wide range of renewable energy sources, including wind and solar power. This makes it a promising solution for decarbonizing not only the energy system, including heat, transportation and electricity, but also the manufacture of a wide range of chemicals, materials, and products. As such, renewable hydrogen can further reduce the reliance on fossil fuels, leading to substantial reductions in greenhouse gas emissions and a transition towards a more sustainable and low-carbon energy system. While small amounts of hydrogen might end up being produced close to the location of its utilization, larger amounts will likely imply a regional separation of production and consumption. Regions with high renewable potentials (i.e., wind (offshore) and solar) could prove to be beneficial for the production of renewable hydrogen, whereas regions dominated by industry could become the main consumers. In this regard, hydrogen transport via pipeline will become increasingly crucial, either through the utilization of existing natural gas infrastructure or the construction of new hydrogen dedicated pipelines. By introducing sensitivities for hydrogen blending in the Global Energy System Model (GENeSYS-MOD), this paper explores how hydrogen blending options affect production, transport options, and regional localization of hydrogen generation in Europe. The study contributes to the current discussion around hydrogen utilization and transport by generating new insights to help guide the conceptualization of a European hydrogen network best fit for its future purpose.

Methods

For this work, a model setup used in the Horizon 2020 project openENTRANCE is used in which low-carbon transition pathways for Europe were modeled in GENeSYS-MOD as part of an open modeling platform. The four pathways represent three very ambitious scenarios and one slightly less ambitious, yet still compatible with a 2 °C climate target, considering different political, societal, and technological developments. The Gradual Development scenario is used as the baseline in this work, representing a moderate mixture of all three dimensions. Europe is disaggregated into 30 regions (mainland EU-25, Norway, Switzerland, UK, Turkey, and an aggregated Balkan region) and a pathway from 2018 to 2050 is calculated in 5-year steps. 2018 is used as a reference year for calibration purposes. To ensure an adequate representation, hydrogen production and hydrogen transport technologies are refined within the model. This includes the possibility of retrofitting natural gas pipelines to allow hydrogen transport. In order to achieve the hydrogen blending within existing natural gas infrastructure, a new fuel (H2_blend) was added to the model formulation. Then, to address the question of how different proportions of hydrogen in natural gas pipelines affect hydrogen production and transportation infrastructure, various sensitivities in the form of model runs allowing different shares of hydrogen are computed. To do this, the model is allowed to add hydrogen (in volume) to the gas network in 5% increments utilizing a dedicated hydrogen switch in the model for each model run from 2018-2050. A model run is performed for each possible ratio from 0% (no hydrogen-blending allowed) to 100% (only hydrogen in existing gas pipelines is allowed), resulting in a total of 21 model runs.

Results

Preliminary results suggest that increasing hydrogen transport through existing natural gas pipelines has a significant effect on regional distribution and trade of hydrogen within Europe. However, the overall demand for hydrogen is highly inelastic given the high CO2 prices and emission reduction targets (100% in 2050). Furthermore, the demand for hydrogen is not very elastic due to its specific use cases and high costs compared to existing competing technologies (e.g. heat pumps and BEV). Hydrogen production and consumption still have high costs which often exceed direct electrification. Europe's consumption of hydrogen remains similar regardless of other factors, but regional production is greatly impacted by the availability of hydrogen transportation through pipelines. With an increasing share of hydrogen in existing gas pipelines, hydrogen trading is increasing in countries with high generation potential. Simultaneously, the use of methanation, an alternative for storing and trading produced energy, is decreasing. As blending becomes more prevalent, Norway becomes a major hydrogen exporter while Turkey's significance decreases. France, Germany, and Italy are the largest hydrogen importers in 2050. However, France's imports decline while Norway stops importing as their own hydrogen production increases (see figure). To summarize, the addition of hydrogen to the existing energy mix does not significantly affect the production and consumption of hydrogen - even when not considering additional costs related to retrofitting. However, its impact on the location of production and the reliance on imported hydrogen, as well as the possibility of creating new dependencies, must be carefully evaluated when planning for hydrogen's future in Europe.

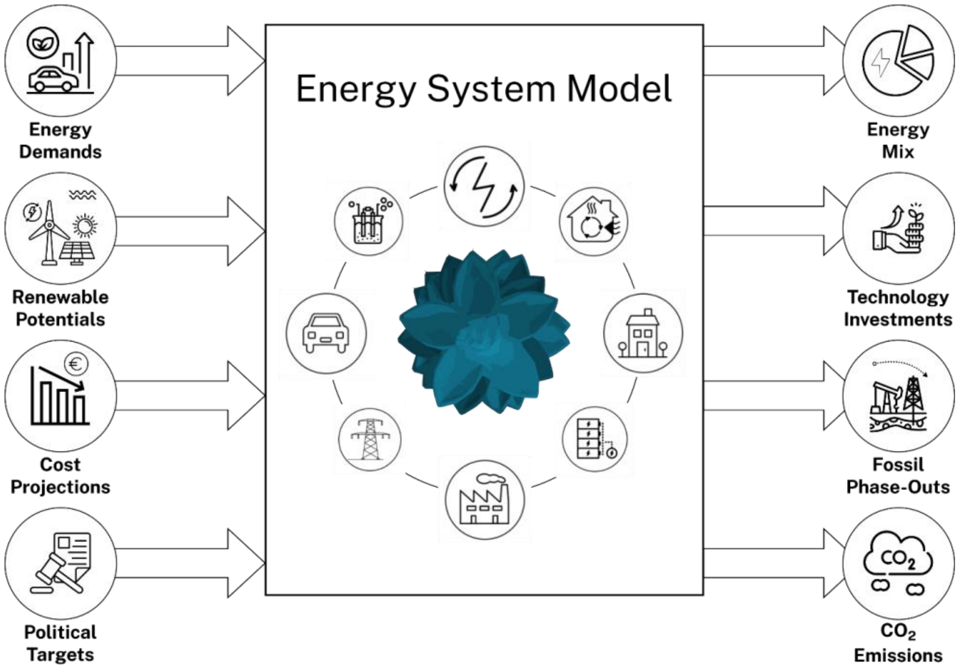

Figure 1

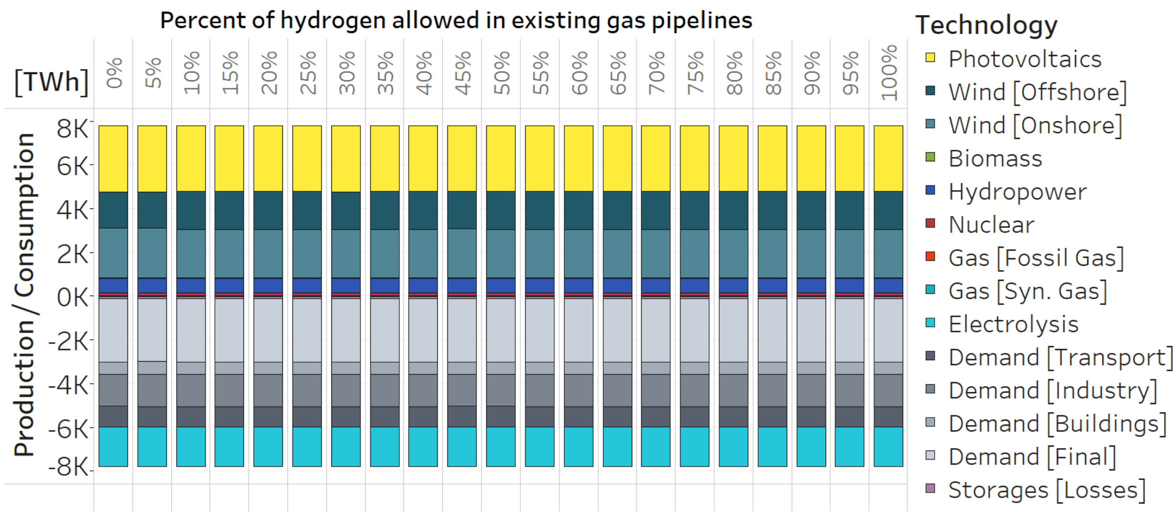

Figure 2

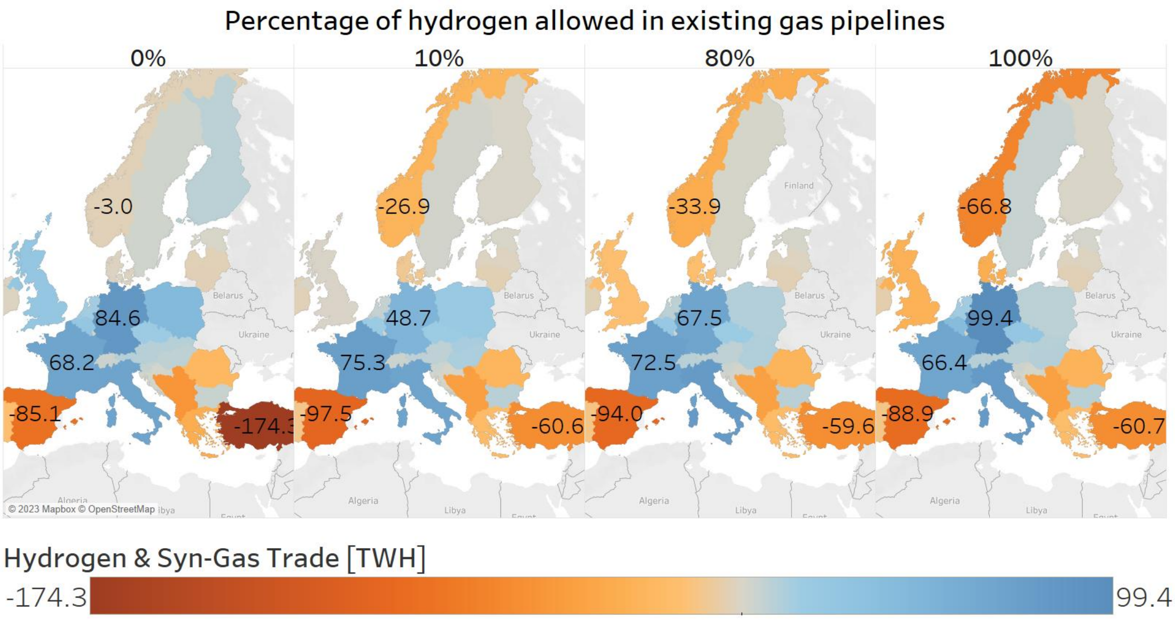
Percentage of hydrogen allowed in existing gas pipelines
0%
10%
80%
100%
-3.0
84.6
68.2
-85.1
-174.3
-26.9
48.7
75.3
-97.5
-60.6
-33.9
67.5
72.5
-94.0
-59.6
-66.8
99.4
66.4
-88.9
-60.7
© 2023 Mapbox © OpenStreetMap
Hydrogen & Syn-Gas Trade [TWH]
-174.3
99.4

Figure 3

Generation options & effects of sustainable hydrogen from offshore wind energy on the German energy system

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Keywords: decarbonization, green hydrogen, offshore wind, energy system modeling, GENeSYS-MOD

Motivation

The increasing demand for renewable energy sources and the need to advance decarbonization in Europe have led to the emergence of hydrogen production from offshore wind turbines in the north of Germany as a promising solution. However, to fully realize the potential of these technologies, it is necessary to evaluate their feasibility in the context of centralized vs. decentralized energy and hydrogen production. This study aims to address this issue by analyzing the potential of using offshore wind for hydrogen production in the north of Germany and exploring the challenges associated with hydrogen transportation and storage. One crucial factor to consider in this analysis is the choice between a central or decentralized hydrogen production system. The corresponding transportation infrastructure for each approach will exhibit marked distinctions, as a centralized system necessitates a well-established hydrogen infrastructure from Northern Germany, whereas a decentralized system entails smaller-scale hydrogen generation capacities but necessitates more power grid expansion. The selection of the production system will depend on various factors, including the availability of renewable energy sources, the proximity of end-users, and the cost-effectiveness of each system. This study seeks to contribute to the existing literature on offshore hydrogen production and decentralized energy production by providing a comprehensive analysis of the feasibility and potential of offshore hydrogen production in the north of Germany in centralized and decentralized hydrogen production scenarios. The aim of this research is to evaluate the economic viability of offshore hydrogen production and its role in decentralized and centralized hydrogen production systems, thereby facilitating the development of a sustainable and decarbonized German energy system.

Methods

For this study, the Global Energy System Model (GENeSYS-MOD) is used to simulate the energy system until 2050 under different assumptions for offshore wind production in the north of Germany and different assumptions for the hydrogen production locations. GENeSYS-MOD is a linear open source energy system model which is tailored to analyze low-carbon energy transition pathways considering all energy sectors: electricity, buildings, industry, and transportation. To facilitate a comprehensive analysis of the impact of offshore wind and hydrogen production, Germany is divided into 16 regions (16 states). Two additional regions have been added to the model (North Sea & Baltic Sea) to account for the offshore wind generation capacities. This allows for an individual scaling of wind capacity expansion potential and enables a better understanding of the effects of alterations in wind-offshore production and hydrogen production on the energy sector, imports, and exports in Germany. Furthermore, hydrogen production technologies were refined to create a more detailed representation of the different technologies and their expected efficiencies and costs until 2050. To refine the representation of renewable energy potential, more detailed weather data and time series were created based on the Atlite software. The scenarios in this study are based on current decarbonization, renewable energy expansion, and offshore wind capacity expansion programs and targets set by the German state and the European Union. Two main scenarios are explored, one with a very ambitious target (1.5 degrees Celsius) and another less ambitious (2 degree Celsius), to gain insights into the technology mix required for each scenario. Furthermore, sensitivities are introduced, to evaluate the effects of different offshore wind capacities on the German energy system and assess the impact of centralized and decentralized hydrogen production on transportation, storage, and overall system costs.

Results

The initial findings of this study suggest that offshore wind production in the northern region of Germany holds the potential to greatly reduce Germany's reliance on imports of energy and hydrogen from outside the country. The scale of offshore wind projects plays a crucial role, with higher capacities requiring greater investment in transport infrastructure, while also resulting in reduced overall costs for hydrogen and power production. The decision to opt for a centralized or decentralized hydrogen production system hinges on various factors, such as the availability of renewable energy sources, the proximity to end-users, and cost-effectiveness. Centralized production at wind power plants or in close proximity necessitates the creation of new hydrogen transport capacities and storage options. In contrast, decentralized production requires additional power lines and investments in production facilities in the area where hydrogen is utilized. Furthermore, the study highlights that given the persistently high costs of hydrogen, careful consideration should be given to the specific locations where hydrogen is utilized when selecting between centralized and decentralized production. Thus, these results underscore the importance of a careful and continuous assessment of the most practical and cost-effective production and transport alternatives for hydrogen, especially in light of the growing demand for renewable energy sources and the urgent need to advance decarbonization in Europe. Although these preliminary findings offer an initial glimpse into the capabilities of offshore wind energy to generate power and produce hydrogen, the model simulations require further refinement and calibration to yield definitive and conclusive outcomes.

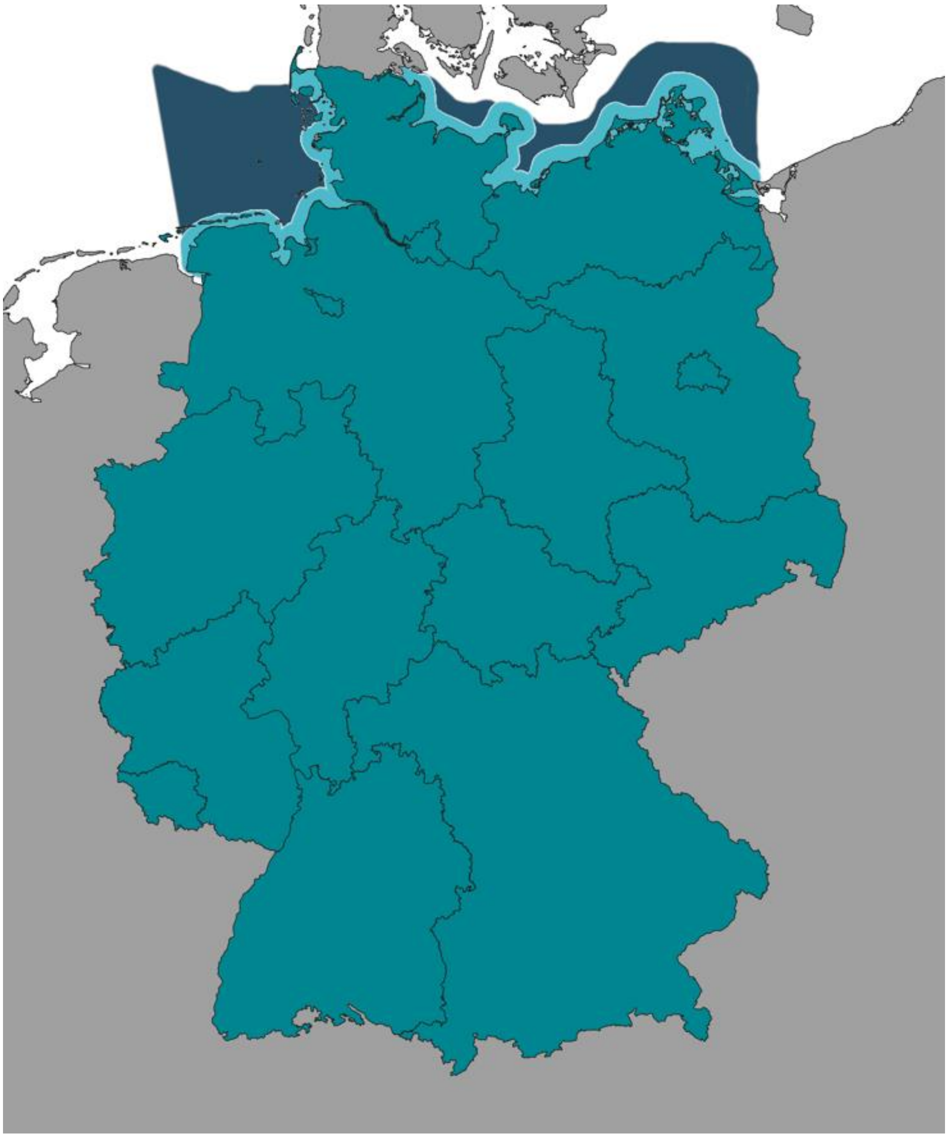

Figure 1

The economics of global green ammonia trade – "Shipping Australian wind and sunshine to Germany"

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Keywords: green ammonia, green hydrogen, linear optimization, global energy transition, hydrogen economy

Motivation

To mitigate climate change effectively and timely, rapid decarbonization of the global economies is required. The transformation is already well advanced in the electricity sector of various industrialized countries, where competitive renewable energy technologies increasingly replace coal- and gas-fired power plants. Climate-neutral electricity will now be used directly or indirectly - via hydrogen and its derivatives - to decarbonize all remaining sectors of the economy. In this context, the production and transport of hydrogen and energy carriers is getting increasing attention, as they have the potential to replace fossil coal, oil, and gas as a global energy commodity. There are several options being considered for the transportation of hydrogen from overseas, including the transportation of cryogenic hydrogen and the use of liquid organic hydrogen carriers. In the short term, the transport of ammonia is particularly attractive, since ammonia and its derivates are already traded worldwide and therefore existing infrastructure can be used. Furthermore, all links in the process chain of large-scale renewable ammonia production are already established and have a very high technology readiness level.

Methods

This paper contributes to understanding the transformation of global energy trade to green energy carriers, focusing on green ammonia as the foreseeable first green hydrogen carrier. We provide a comprehensive overview of today's ammonia trade and assess scaling options for the trade of green ammonia. To that aim, we develop an optimization model for the integrated assessment of the green ammonia value chain that covers all steps from green ammonia production in an exporting country, up to delivery to a harbor in an importing country. The model endogenously chooses among different technology options and determines cost minimal operation. In a case study, we apply the model to the large-scale import of ammonia from Australia to Germany in a scenario for 2030.

Results

The Australian-German case study yields average levelized cost of green ammonia of 109.39 €/MWh (566.64 €/t) at the harbor in Germany and 159.18 €/MWh (5.3 €/kg) for green hydrogen from cracked ammonia for the year 2030. The results show that green ammonia can reach cost parity with gray ammonia even for moderate gas prices (but not necessarily with blue ammonia) if CO2 prices are high enough. We also provide a sensitivity analysis with respect to the interest rate and other key technical and economic parameters, such as electrolysis efficiency and capex of various relevant technologies. In addition, our results show that cracking ammonia to provide pure hydrogen comes at a 45 % cost markup per MWh at the destination. Thus, it is advisable not to convert ammonia that has been imported. Instead, it is better to meet the demand for ammonia in the country of destination through ammonia imports, either for feedstock or for direct energy applications. For meeting the demand for hydrogen, it might be better to rely on regional production or pipeline imports, which enable the transportation of compressed hydrogen. Gaseous hydrogen imported by pipeline will likely be the most cost-effective option. However, it is unlikely that the amount of hydrogen available through this method will be sufficient to meet the long-term needs of Europe alone. Therefore, the importation of hydrogen from overseas, which will be initiated by importing green ammonia, will play an important role on the way to a hydrogen economy.

Session 11:15 – 12:15
PV and storage

Room: HSZ/0304
Chair: Lisa Lorenz

Smart energy protocol landscape in Germany
Christoph Parsiegla, *P3 Group*

Determinants of residential photovoltaic and battery storage adoption in Germany: An empirical investigation
Stephanie Stumpf, *Karlsruhe Institute of Technology*

Energy storage as enabler for the transition to a sustainable energy system: What will be the winning battery technology?
Jakob Gross, *P3 Group*

Smart energy protocol landscape in Germany

Christoph Parsiegla[1]

[1]*P3 Group, p3_aut_conferences_electrify@p3-group.com*

Keywords: EV, vehicle to grid integration, smart charging, open communication protocols, standards

Motivation

As part of Germany's climate protection efforts, the transportation sector is expected to significantly reduce its CO2 emissions. The coalition parties have set a target of having at least 15 million electric vehicles registered in Germany by 2030, which will require a comprehensive expansion of the charging infrastructure. The government parties have also committed to enabling bidirectional charging, which will allow excess electrical energy from the power grid to be stored in electric vehicles and returned later to help stabilize the grid. The increasing use of renewable energy for electricity generation in Germany has the advantage of reducing greenhouse gas emissions but the disadvantage of creating more irregularities in electricity production. To address this, it will be necessary to store electrical energy, and electric vehicles are ideal for this purpose due to their large battery capacities and low usage rates. In the coming years, grid operators and technology providers will need to determine how to intelligently integrate electric vehicles and which communication technologies make the most sense from a technical and economic standpoint. Therefore, it is important to identify which use cases are most relevant for this integration.

Methods

The primary driver for incorporating electric vehicles (EVs) into smart grid operations is their potential to offer grid services. The aim of this research paper is to explore the technologies that enable EVs to function as Mobile Distributed Energy Resources (DERs) efficiently. The focus of this study is to provide an overview, implementation, and testing of these technologies. To identify any technical gaps and suggest solutions to bridge them, only a few technologies are selected for implementation. Additionally, this study delves into interoperability problems in the e-mobility field. The primary research question addressed in this work is: What are the technical requirements for converting an EV into a smart mobile DER? The primary inquiry can be broken down into constituent parts, which are formulated as the subsequent sub-queries:

• What types of grid services can be offered by EVs? The primary reason for integrating EVs into the smart grid is to provide grid services. To determine the most suitable grid services that EVs can provide, the implementation and testing of various grid services are carried out.
• What are the necessary communication protocols to fulfil these services? Aggregation is a crucial element for effective EV integration. It is imperative to discern the communication necessities between EVs and aggregators.
• Before proceeding with the integration of e-mobility into the smart grid, it is crucial to evaluate the current status of EV technology development concerning grid integration.
• After evaluating the current state of technology and its applications, the primary technical challenges that exist for EV integration are identified, and solutions are proposed for future development.
• When integrating EVs for grid applications to enable a wider range of resources to provide grid services, EV interoperability should be considered. However, in this work, interoperability issues are not discussed as part of the technical assessment of e-mobility.

Results

Norm experts argue that while standards provide a good starting point for interoperability, they may not be properly implemented in practice. If the protocol specification allows for interpretation, this can lead to conflicts between implementation and interoperability. Therefore, it is crucial to specify the standards clearly and in detail to ensure correct implementation. In addition, conformity tests and official product certifications can show whether the standards are being properly implemented. Although conformity tests and certifications are not common in new market conditions, they can help prevent interoperability gaps caused by unexpected consequences of protocol implementation. Therefore, it is important that the open protocol is tested before implementation and that coordination takes place between the various actors in the EV ecosystem (such as electricity network operators, grid operators, and car manufacturers).To address these challenges and minimize the possibility of interoperability gaps, it is proposed to create a new platform for collaboration on the integration of vehicle network protocols. This platform, supported by governments or industry associations, would bring together important companies in the mobility and energy sectors that would not normally work together to advocate for the adoption of open communication protocols and facilitate the development and implementation of standardized protocols.The successful introduction of electric vehicles depends on their suitable integration into the power grid, while minimizing the associated costs of network expansion and considering the integration of renewable energy sources. Universal support for the network integration of electric vehicles can be facilitated through open communication protocols, which connect the various actors and devices in the electric mobility ecosystem and improve compatibility and communication between them.

Determinants of residential photovoltaic and battery storage adoption in Germany: An empirical investigation

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Keywords: technology adoption, residential sector, home storage systems, rooftop photovoltaic, structural equation modeling

Motivation

The energy transition poses multiple challenges, such as the more volatile generation of wind and solar energy. One way to overcome these fluctuations are battery storage systems, which can be deployed either on a grid scale or on a household scale as home storage systems (HSSs). In most cases, HSSs are used in combination with photovoltaic (PV) systems to store self-generated electricity when generation exceeds household demand. This allows for increased self-consumption and grid autonomy (Jasper et al. 2022). In Germany, incentives for self-consumption have increased in recent years due to cuts in feed-in tariffs, rising retail electricity prices, and the drop in lithium-ion battery prices (Kairies et al. 2019). In addition, the recent energy crisis seems to be reinforcing households' desire for more independence from the grid. In 2022, 70% of small-scale PV plants in Germany were installed with a HSS. In total, about 630,000 HSSs with a cumulative capacity of 1.9 GWh have been installed so far (BSW-Solar 2023). Although the market shares of PV and HSS are still very different, the maturity of PV is driving the diffusion of HSS. Previous research on residential PV has indicated that their adoption is not only linked to long-term investment motives, but also to environmental and other personal values of adopting households (Schulte et al. 2022). However, while there is extensive research on PV adoption, little is known about the extent to which HSS adoption depend on similar factors. A holistic understanding of the key factors is important to better grasp the diffusion processes of PV and HSS, as well as their interactions. Therefore, this study aims to contribute to the growing literature on HSS adoption by presenting a survey on the predictors of intention to adopt PV and HSS in Germany. In particular, we focus on psychological and social determinants of adoption of both technologies, considering differences between the two and between adopters and non-adopters.

Methods

In order to investigate the determinants of PV and HSS adoption, we reviewed the relevant literature from different research streams. Previous studies have tried to explain PV adoption from different theoretical angles, indicating that both rational and moral motivations are related to adoption decisions. In one comprehensive study, Wolske et al. (2017) provide a model for PV adoption that incorporates three complementary theories that have often been shown to be useful in explaining technology adoption behavior. These theories are the Diffusion of Innovation Theory (Rogers, 2003), the Value-Belief-Norm Theory (Stern 2000), and the Theory of Planned Behavior (Ajzen, 1991). We build upon this model by extending it to HSS and adapting it accordingly to both technologies. In order to test the adapted models, we conducted a survey that was distributed via a commercial online panel between August and September 2022. The sample was representative of the German population regarding age, gender, income, and household size. Complete responses included those participants who passed an attention-check item and had no missing data on one or more variables. The final sample included 809 participants, 80 of whom had already adopted PV and 37 of whom had a HSS. For our analysis, we considered sociodemographic characteristics as well as personal values, beliefs, and attitudes toward both technologies. Also, we examined external influences, such as exposure to solar marketing or the observability of the two technologies. After performing a confirmatory factor analysis to assess the validity of the adapted model, the data were analyzed using covariance-based structural equation modeling (SEM) with maximum likelihood estimation.

Results

Preliminary results show that the framework developed by Wolske et al. is suitable to explain the intention to adopt PV as well as HSS in Germany. For both technologies, we find that concerns regarding expenses have a negative effect on adoption, while prceived behavioral control, and subjective norm have a positive effect. Beyond these similarities, we also find some differences in the effects of specific beliefs about each technology on the respective adoption intention. In addition, preliminary results show that the effects of various factors regarding technology adoption differ between adopters and non-adopters. Based on the results for both models, implications for energy policy are presented.

Energy storage as enabler for the transition to a sustainable energy system: What will be the winning battery technology?

Jakob Gross[1]

[1]P3 Group, jakob.gross@p3-group.com

Keywords: BESS, energy storage system, levelized cost of storage, lithium-ion battery, redox-flow battery

Motivation

On EU's way to a net zero, a transition to carbon neutral energy sources as solar and wind is inevitable. Currently, longer periods of low solar intensity and low wind are compensated by electricity, generated by carbon-based power plants like gas and coal. However, when share of renewables is getting closer to 100%, energy must be stored and buffered to increase security and quality of power supply. Already today, many different mechanical, thermal, chemical, and electro-chemical energy storage technologies are in operation and a clear winner has not yet been identified, yet. Lithium-ion is currently dominating the electro-chemical storage market not only in mobile but also in stationary applications. However, new technologies are emerging, and may gain relevance as rules of the game are being changed with completely different requirements compared to mobile applications (e.g., reduced relevance of energy density and increased relevance of lifetime). It can be expected that, depending on the specific use case, a bunch of different technologies will co-exist to cover different energy/power levels, shorter and longer discharge durations and different locations of energy demand. It is important to get a comprehensive understanding of challenges and requirements of each energy supply use case and the according capabilities of each storage technology to be able to select the right energy storage solution.

Methods

In order to provide a general understanding of energy storage technology, a basic overview of all relevant categories of energy storages (mechanical, thermal, chemical, and electro-chemical) and a more detailed overview of electro-chemical energy storages will be provided. Furthermore, different integration levels (power generation, transmission & distribution and end-user side) and use cases (e.g. load leveling, congestion relief, peak-shaving, frequency regulation, black start, uninterrupted power supply) of energy storage solutions in power grids will be analyzed. On this basis, use case specific requirements for energy storage solutions will be derived. To identify the most suitable technologies, a KPI comparison will be shown, considering the most differentiating and most relevant criteria, such as space requirement, safety, efficiency, sustainability, and cost. As energy services are not only sensitive to purchasing cost but to all capital and operating expenditures over lifetime, levelized cost of storage (LCOS) will be calculated for specific storage technologies. Not only technology but also market related developments will elaborated in this presentation. The stationary storage market was modelled by P3 for different use cases and integration levels.

Results

Based on P3's industry and technology insights, a comprehensive overview of different energy storage technologies will be provided. It will be shown, which technology will potentially be the best solution for specific energy service use cases. Levelized cost of storage (LCOS) as the most relevant metric to evaluate and compare cost of different technologies will be shown for different battery solutions and different high-energy / high cycling use cases (e.g. load leveling increased PV self-consumption, congestion relief, peak-shaving). Overview about the most relevant future electro-chemical battery storage technologies based on holistic KPI comparison. Based on announced production capacities and political targets, expected market volumes and growth rates will be shown for specific battery applications. Relevant players in the battery energy storage solutions market will be shown and characterized and growth potentials for European players will be identified. As a conclusion, the role of BESS for EU's development of a resilient energy supply will be highlighted considering the securing of critical raw materials for certain battery technologies.

Keynote 13:15 – 14:00

Room: HSZ/0004, hybrid
Chair: Prof. Dr. Christian von Hirschhausen

Trends in European and international gas markets in the energy sector transformation

Prof. Dr. Anne Neumann[1]

[1]*Norwegian University of Science and Technology (NTNU)*

Session 14:05 – 15:05
Energy system modeling III

Room: HSZ/0004, hybrid
Chair: Andreas Büttner

Exploring the untapped potential of renewables and flexibility options in reducing CO_2 emissions - What will it cost?
Steffi Misconel, *EURAC Research*

Impact of non-linear CO2 price fluctuations on investments in the power sector
Erdal Tekin, *IER University of Stuttgart*

Navigating to a greener Europe through clean electricity procurement
Iegor Riepin, *Technische Universität Berlin*

Exploring the untapped potential of renewables and flexibility options in reducing CO_2 emissions - What will it cost?

Steffi Misconel[1]

[1]*EURAC Research, steffi.misconel@eurac.edu*

Keywords: marginal CO2 abatement cost curve, decarbonization policy, sector coupling, flexibility option, linear optimization

Motivation

Exploring pathways for transitioning to clean energy to achieve climate change mitigation goals is essential. Addressing the economic impact of decarbonization options requires strategic planning to determine cost-effective CO2 mitigation strategies. The assessment of marginal CO2 abatement cost curves (MACCs) is a commonly used method by policymakers, strategic planners, and researchers to link costs and emission reduction of individual decarbonization measures, together with the cumulative CO2 abatement potential and associated costs for a certain period. MACCs provide a clear understanding of cost-effective abatement options, allowing for the prioritization of investment in the most promising options. The decarbonization measures are ranked based on increasing CO2 abatement costs to ensure the implementation of the least-cost pathway toward achieving emission reduction targets. This study aims to calculate a step-wise MACC to identify the most cost-effective order of investments in decarbonization measures for the German sector-coupled energy system from 2030-2045.

Methods

There are various methods for calculating marginal CO2 abatement cost curves, such as distance functions, general computational equilibrium, or optimization models, each with its advantages and limitations. However, many of these approaches lack detailed information on the temporal, sectoral, and techno-economic resolution of CO2 reduction, producing continuous MACCs that can only be converted into more detailed step-wise MACCs through decomposition analysis. Additionally, the interplay between technologies across different sectors is often not considered when calculating MACCs. Moreover, existing MACC analyses usually provide insights for a snapshot of one year and often neglect the long-term strategic planning for a decarbonization pathway over several years or decades, so-called path dependency. This research aims to address these limitations by introducing a MACC approach based on a modified dispatch version of the bottom-up linear optimization model ELTRAMOD. The objective of this research is to calculate detailed model-derived step-wise MACCs by integrating a multi-iterative capacity expansion algorithm into ELTRAMOD to determine the minimal cost of CO2 abatement (CCA). A case study on the German sector-coupled energy system serves to identify the most cost-effective order of investments in decarbonization measures and to provide insights on the techno-economic, intertemporal, and intersectoral interactions of measures for the long-term decarbonization pathway from 2030 to 2045. A further contribution is a reliance on input parameters drawn from the current German climate and grid development plan, which includes recent expansion potentials for various decarbonization measures. Moreover, the presented approach is adaptable to other large-scale and single-node linear optimization models, making it a valuable tool for identifying cost-effective solutions and presenting the results through easily understandable graphical representations of step-wise MACCs.

Results

The results indicate that during the early phase of a decarbonization pathway, it is more economical to install vRES, even if it leads to some curtailment. As the process advances, the energy infrastructure's ability to integrate vRES should be improved by implementing sector coupling and energy storage. Further results indicate that by 2030, ground-mounted PV, onshore wind, and heat pumps with negative CCA are the most cost-effective decarbonization measures, while offshore wind, PtH2tP, and batteries are the most expensive. By 2045, ground-mounted PV remains the most cost-effective measure, while investments in BEV with controlled bi-directional charging and PtH become cost-effective too in an earlier stage. In contrast, offshore wind, rooftop PV, and batteries are the most cost-intensive measures by 2045, with marginal CO2 reduction at exceptionally high CCAs. During the decarbonization pathway from 2030 to 2045, PtH2tP has the highest potential for CO2 abatement but is also cost-intensive. With RES shares of >85%, the CO2 abatement potential of additional vRES is marginal, particularly in 2045, even with sufficient storage capacity from BEVs, PtX, and batteries. Curtailment increases with rising vRES, despite the additional electricity demand through sector coupling, which leads to the conclusion that the level of flexibility offered by sector-coupling and storage technologies is inadequate or insufficiently adaptable to effectively integrate a significant proportion of vRES. Moreover, backup capacities (i.e., H2 power plants) are still required in 2045, particularly during periods of high residual load. To meet striving decarbonization goals, a range of low-cost and higher-cost measures will be needed to achieve the necessary scale of deployment. Overall, the presented step-wise MACC approach can support policymakers in determining the most cost-efficient energy strategy by identifying the optimal technology mix to meet specific climate goals.

Impact of non-linear CO2 price fluctuations on investments in the power sector

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Keywords: CO2 price, EU power sector, investments

Motivation

Energy prices were subject to strong fluctuations in recent times. Simultaneously, the EUA prices rose from around 30 Euro/t up to over 90 Euro/t within a year (EEX,2023). Also historically, the price for carbon allowances varied nonlinearly, amongst others due to economic crises, changes in policy instruments, announcements of stricter reduction goals and an energy price crisis. However, in policy impact analyses, carbon allowance prices are often assumed to rise linearly and usually don't take disruptions and volatility into account. But volatile prices influence the individual decision for investments conducted by the market participants as they rely on the perceived financial and political framework. In studies with linear growth, this has not been taken care of. This leads to under- or overestimation of investments. But sufficient investments are necessary for the transformation process, especially in the power sector as the electricity demand will rise due to the electrification of processes. Therefore, this work contributes to the question of how the non-linear variation of EU allowance prices will affect the electric market which is required to transform its powerplant infrastructure.

Method

In the German media outlet and scientific community in the field of energy economics, several studies were published in the last two years in which the transformation process of the energy sector is examined. Among others, there are studies by (Sensfuß et al., 2022: "Langzeitszenarien"), (dena, 2021: „dena-Leitstudie Aufbruch Klimaneutralität), (Prognos, Öko-Institut, Wuppertal-Institut, 2020: "Klimaneutrales Deutschland") and (Kopernikus-Projekt Ariadne, 2021: "Ariadne-Report: Deutschland auf dem Weg zur Klimaneutralität 2045") which propose different transformation processes for the German and EU-wide to a climate-neutral energy infrastructure. All of those energy system and sector market models used for these publications besides the DENA report -which didn't name carbon price trajectories- accounted for the carbon allowance prices by the assumption of piecewise linear growth of the prices without disruptions or variations. These do not only not account for the historic price developments as they neglect possible exterior effects but also they neglect the theoretically expected trajectory of price developments for EU allowances within a cap and trade system. Ellerman et al. among others showed in an empirical evaluation that the optimal price paths for cap and trade systems should contain a steep price increase in the beginning followed by a slow and steady growth (Ellerman et al., 2002). Other than that, carbon price developments are the focus of forecasting methods with probabilistic approaches. With that in mind, an electricity market model is used to depict the European electric energy infrastructure and several scenarios for non-linear EU allowance prices are developed based on different political storylines and deducted from historical developments. In those scenarios, only carbon prices are varied yearly up to 2030. This explorative scenario analysis is carried out to express the possible impacts of non-linear EU allowance price behavior.

Results

We look especially at results among the invested capacities, their responsive profits or revenue gaps and costs for electricity consumers. Among other effects, it is expected that higher EUA prices indicate investments in renewable energies being pulled forward, supporting the achievement of high emission reduction in the short term. We will also look at the question, whether different EUA price trajectories will trigger different target compositions of the generation mix in 2030. Fossil-fueled power plants are expected to become non-profitable in the medium term, but the EUA price trajectory might influence the point of time, which might decide whether those capacities are profitable over their lifetime or become stranded assets. Furthermore, it is expected that a heavy EUA price drop will lead to exceeding the emission budget and enable fossil fuel investments that are not profitable in the medium term. Although the consumer prices for electricity usage may rise for scenarios with a steep early increase, these increases may be necessary and also beneficiary for the cumulative transformation process of the energy system.

Navigating to a greener Europe through clean electricity procurement

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Keywords: clean energy procurement, electricity markets, energy system modelling, renewable energy

Motivation

Climate change has spurred global efforts to rapidly decarbonise electricity systems. Numerous public and private energy buyers have joined this movement, showcasing their sustainability by procuring renewable energy through Power Purchase Agreements (PPAs). PPAs generally enable renewable energy supply and demand to be balanced over extended periods. For instance, over 360 members of the RE100 group have pledged to purchase enough renewable energy to offset 100% of their annual electricity consumption. Such commitments drive wind and solar capacity deployment beyond policy requirements in the regions where these companies operate. Nevertheless, energy buyers committing to 100% renewable energy annually still encounter periods when wind and solar generation cannot meet their electricity demand. During these hours, they often depend on carbon-emitting power sources, like coal and gas, available in local markets. Consequently, the energy demand met by annual matching schemes is not entirely carbon-free. Moreover, the 100% annual matching approach exposes buyers to price volatility and necessitates backup and flexibility options for low renewable generation periods. Due to these limitations, there is growing interest from corporate and industry energy buyers in achieving 24/7 Carbon-Free Energy (CFE), which entails matching every kilowatt-hour of electricity consumption with carbon-free sources around the clock. This method could potentially eliminate all carbon emissions related to their electricity usage. Further, the 24/7 CFE procurement can have a number of positive system-level effects.

Methods

Methodologically, our modeling workflow is based on PyPSA (Python for Power System Analysis) - an open-source software toolbox maintained by TU Berlin for simulating and optimizing modern energy systems at high resolution. The model developed for this study optimizes investment and operational decisions to meet projected electricity demand for consumers engaging in clean energy procurement, as well as demand for other consumers in the European electricity system, while meeting all relevant engineering, reliability, and policy constraints. This research project is also open-source and can be found at https://github.com/PyPSA/247-cfe. In this study, we introduce a set of new constraints to model a situation where a portion of corporate and industrial (C&I) demand commits to the 24/7 CFE goal. These constraints ensure that a portfolio of carbon-free generation, located in the same market as the participating C&I consumers, covers their electricity demand profiles every hour of every day. The mathematical implementation allows for the examination of a scenario space in which varying shares of demand pursue the 24/7 approach with different thresholds for meeting the hourly clean energy requirement (e.g., 90%, 95%, 100%). For comparison, we also model a benchmark scenario wherein C&I consumers meet their annual energy demand on a volumetric basis with renewable energy procurement (the 100% annual matching), as well as a scenario with no voluntary procurement of carbon-free energy. We model scenarios where C&I consumers are located in different national markets across Europe. Our aim is to generalize the impacts of 24/7 CFE procurement, accounting for diverse patterns of electricity demand, weather, renewable resource availability, existing electricity generation capacity, national climate and energy policies, and other factors.

Results

We investigate 24/7 clean energy procurement impacts both the participating C&I consumers (influencing the average costs of procured electricity and carbon emissions associated with the consumers' electricity usage) and the electricity system as a whole. For the latter, we examine both short-term impacts (market dispatch, revenue streams for electricity generators, system emissions) and long-term impacts (exit of fossil-fueled generators from the market, improved market conditions for storage, and new clean firm technologies like geothermal power or advanced nuclear technologies). Our results reveal that:

- 24/7 CFE leads to lower emissions for both the buyer and the system, as well as reducing the needs for flexibility in the rest of the system. We explore and explain two mechanisms how 24/7 CFE lowers emissions in the local grid.
- Reaching CFE for 90-95% of the time can be done with only a small cost premium compared to annually matching 100% renewable energy.
- Reaching 100% CFE target is possible but costly with existing renewable and storage technologies, with costs increasing rapidly above 95%. 100% CFE target could have a much smaller cost premium if long duration storage or clean dispatchable technologies like advanced geothermal are available.
- 24/7 CFE procurement would create an early market for the advanced technologies, stimulating innovation and learning from which the whole electricity system would benefit.

In summary, we demonstrate that the 24/7 CFE commitment by corporate sector stakeholders goes above and beyond the 100% annual renewable matching in paving the path toward carbon net-zero energy systems. This voluntary commitment also provides a range of societal benefits by

(i) triggering innovation, availability, and earlier utilization of advanced clean firm generation needed for transforming energy systems into a fully carbon net-zero state, (ii) reducing system emissions, and (iii) decreasing system flexibility requirements.

Session 14:05 – 15:05
Smart grid and tariffs

Room: HSZ/0401, hybrid
Chair: Philipp Riegebauer

Smart network tariffs: Managing demand peaks in residential electricity distribution
Roman Hennig, *TU Delft*

Effects of electricity pricing schemes on household energy consumption: A meta-analysis of academic and non-academic literature (online)
Tarun Khanna, *Mercator Research Institute*

A methodological approach for developing smart grids - Determining main drivers and match appropriate projects to meet local needs
Philipp Riegebauer, *BABLE GmbH*

Smart network tariffs: Managing demand peaks in residential electricity distribution

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Keywords: network tariffs, congestion, electric vehicles

Motivation

The way in which tariffs for electricity distribution networks are designed needs to be improved. Smart tariffs that reflect the new dynamics of the energy system are needed to avoid grid overloads and to incentivize electricity producers, consumers and battery operators to use the electricity networks in an efficient manner. For example, in the Netherlands distribution grids were typically designed with an assumption of 1.6 kW of coincident load per household. This made sense in the past when the coincidence factor of loads was statistically rather low when averaged over many households. But with an increase in high-power loads such as electric vehicles and heat pumps, which can have peak demands of up to 22 kW per device, this assumption may no longer hold. This is exacerbated by the fact that these devices may be increasingly controlled remotely and react to wholesale prices, which can lead to much higher coincidence factors. One solution that is often called for to upgrade the network infrastructure to the point where it can accommodate these higher peak loads. But this may be impractical for several reasons: First, it is likely not possible at the required pace, as there is currently both a labour and supply shortage. Secondly, it would be societaly inefficient to design networks that can accommodate the highest peaks, when this will only be used during very few periods of the lifetime of these assets. And thirdly, in many instances it is also not necessary. These new types of enduses are also highly flexible and often do not need to run at their peak power in order to satisfy the underlying demand. Thus, while network upgrades will play an important role over the long run, in the short term it will also be necessary to find ways to make use of this flexibility and flatten demand peaks.

Methods

The starting point for our study was based on discussions with stakeholders in the industry in the Netherlands. We then conducted an extensive literature synthesis of proposed network congestion management methods in the literature were we developed a design framework and risk classification of such methods. Further, we developed a model for performance assessment of network tariffs based on quantifiable indicators and performed a case study where we tested several potential tariffs.

Results

We found that network congestion problems are characterized by certain dilemmas: Discrimination of users based on the prevalence of congestion in the network, an information asymmetry between network operators and users and high spatial and temporal complexity. These dilemmas make it difficult to find congestion management methods that simultaneously fulfill all desired objectives. We found several of the proposed solutions to be unfitting for the specific context of residential urban networks because of critical shortcomings with respect to how they tackle the dilemmas mentioned above. One potential way of flattening demand peaks is by making network tariffs smarter. Tariffs are charged by the network operator for network usage. Currently, many operators employ tariffs that are based on simply fixed charges per connection and volumetric fees per kWh of energy delivered through the network. However, these strategies are insufficient to flatten the expected future demand peaks and remove congestion, as they do not constrain or disincentivize the maximal power consumption of endusers. One proposal that stood out because of its balanced treatment of all of the dilemmas was a new form of network tariff: A capacity subscription. In this proposal, network users sign up for a desired amount of network capacity within which they can use the network at low prices, while exceeding the subscribed amount is either inhibited by technical measures or strongly disincentivized by financial penalties. In our case study, we found that this tariff performs particularly well for situations with high number of flexible loads such as EVs. It restricts excessive network peaks and is more cost-reflective than currently used tariffs such as fixed and volumetric tariffs. We found it to be particularly effective when it is applied in a dynamic fashion, were the capacity constraint is only activated during times of heightened network stress.

Effects of electricity pricing schemes on household energy consumption: A meta-analysis of academic and non-academic literature (online)

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Keywords: demand response, price elasticity, renewable energy integration

Motivation

Time-varying electricity prices of electricity, or dynamic pricing, for households, are targeted toward shifting or reducing electricity demand through price incentives. This is important for energy efficiency, system planning, and emissions mitigation. Reducing peak demand can substitute generation capacity at a given level of security of supply. Moving electricity demand to periods when electricity generation by wind and solar is abundant is necessary for the decarbonization of the energy system in long-term net-zero emissions scenarios. Such flexibility reduces the cost of renewables integration, avoids curtailment, and substitutes other, most costly flexibility options such as fossil power plants or energy storage. With increasing electrification of transport and heating, it is important for the system to evolve so that the additional electricity demand can be directed to a time of the day when the marginal emissions intensity of electricity generation is low. Dynamic pricing can also reduce total energy consumption. Various utilities around the world have piloted dynamic pricing. Despite this growing evidence, a rigorous assessment of the existing evidence is missing.

Methods

This paper presents a comprehensive, machine-learning-assisted systematic review of the empirical literature aimed at shifting or reducing the energy consumption of households in line with latest standards for systematic reviews and the Open Synthesis Principles. Our search of the published literature is supplemented by a novel data source: compliance reports submitted by utilities in North America to electricity regulators assessing their dynamic pricing experiments. This results in a large dataset of around 85 studies and 650 observations from 14 countries which is four times larger than any existing dataset. Our dataset includes the latest pilots and studies not only from the United States, UK, and Canada but also China, Japan, Asia, and India. We estimate the effect of dynamic pricing on not only the peak demand for electricity but on total electricity consumption and off-peak consumption. To explain differences in its estimates reported in previous studies we coded over 27 parameters that capture study characteristics to assess when dynamic pricing schemes are most effective. Importantly, we are able to assess the role of the size of the monetary incentive in achieving the reductions. One obstacle that we face is the uncertainty over which of the study characteristics should be included in the model. To address this, we employ Bayesian model averaging - a method that estimates many regressions consisting of subsets of the potential explanatory variables and weights them by model fit and model complexity. Since about half of our dataset comes from compliance reports and not peer-reviewed literature, it provides us with a unique opportunity to perform an extensive analysis of the publication bias in this literature. We supplement this analysis with a critical appraisal of studies and an assessment of the impact of study designs, out-of-sample bias, and scalability on the results of pricing pilots.

Results

Our analysis shows that dynamic pricing seems to result in peak shaving rather than shifting. The average reduction in peak consumption was about 8.5% across studies after adjusting for publication bias. The reported average reduction in total demand is about 1.5% and there is no statistically significant change in the average reported off-peak demand. This implies that subjecting households to dynamic pricing leads to negligible peak shifting but rather to peak shaving, with reductions in both peak and overall consumption. Our analysis of heterogeneity in the reported effect sizes across studies shows that the average peak-to-off-peak price ratio of 4:1 reduces peak demand by about 6.5%, with decreasing marginal reduction as the peak prices are increased. There is no evidence that an increase in the size of the monetary incentive leads to marginal reductions in total consumption. The effectiveness of dynamic pricing varies across countries and is enhanced by the presence of enabling technologies like in-home displays. Estimates of reductions are higher for studies where households are required to opt into experiments. Lastly, comparing the results from academic and grey literature allows us a unique glance into the nature of reporting in this field. We estimate statistically significant small study bias in reporting of consumption reductions in the peer-reviewed literature, while there is no detectable publication bias in the reports from grey literature.

A methodological approach for developing smart grids - Determining main drivers and match appropriate projects to meet local needs

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Keywords: smart city, smart grid, roadmap, carbon-neutrality, MCA, scale-up

Motivation

Meeting the ambitious EU climate change and energy policy objectives for 2030 and beyond will require a major transformation of our electricity infrastructure. It is of utmost importance to reinforce and upgrade existing networks to allow the integration of and increasing number of renewable energy generation and distributed energy resources (DERs) coming onto the grid. The work will give insight into smart and flexible grids in the context of a connected and smart city. The paper introduces a practice-oriented systematic to develop smart grid functionality to reach sustainability goals with consideration of city specific circumstances.

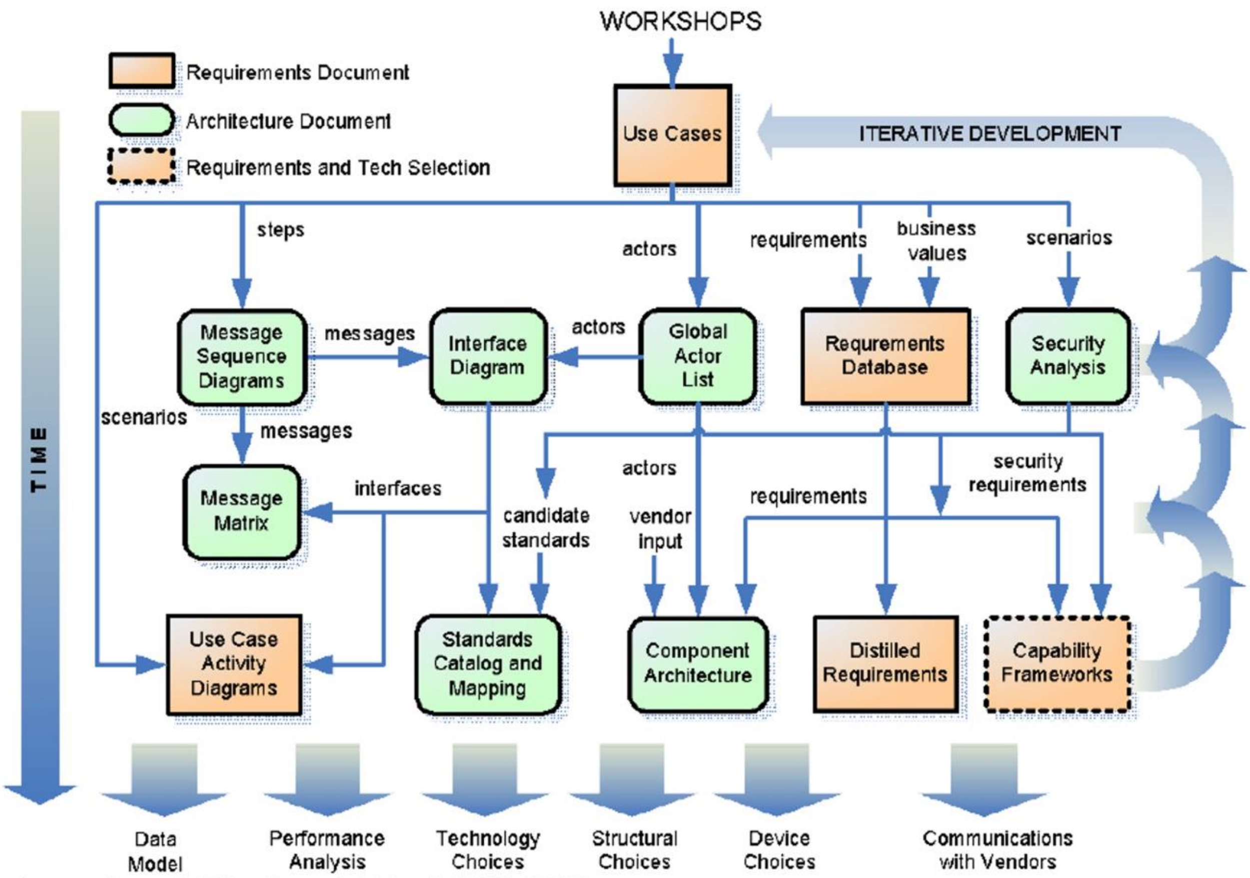
Methods

The methodological approach for developing smart grids is a dynamic plan that describes the steps to achieve agreed goals on a defined time frame, leaving some flexibility to be adapted to the evolving market and changing needs. It also helps to identify the technical, policy, legal, financial, market, and organizational barriers that lie before these goals, and the range of known solutions to overcome them. The approach aims to establish the baseline conditions and state-of-play regarding smart grid technologies and how they fit into the local electricity system as a whole, considering factors such as available technologies, human capacity, and grid interconnectivity. (Figure 1) For the concept of the scale-up roadmap, the technologies are evaluated based on a Multi-Criteria Assessment (MCA). This analysis highlights the city-specific potential for technologies to decarbonize the energy system considering several key criteria co-identified with the city/region. (Figure 2) Reflecting the CO2-reduction potential of technologies and digital solutions the work identifies key tools, outlines major development milestones, and prioritizes technologies based on their potential to be implemented and upscaled.

Results

As the expected benefits from technologies are often a concrete response to one or more local and national needs e.g., technical grid upgrades, economic, social, or environmental. It is critical to review and agree on the key drivers, based on sound data and forecast analyses. The methodological approach will elaborate that multilevel governance is critical and that national and local energy system policy, strategy and system regulation cannot be treated in isolation. It will be stated that energy policy needs to treat distributed generation and (aggregated) demand response equally and in the same framework. (Figure 3) Beside policy implementations the practical application of the methodological approach for developing smart grids in a particular city/region is shown. The approach is applied on the carbon neutrality goal of the city of Leipzig. A scale-up roadmap distinguishing five different sectors for smart energy solutions to reflect interdependencies and sector coupling effects is the result. Linking smart grid and digitalization with technical development steps and interdependencies encompasses

• digital & transmission infrastructure,
• renewable and sustainable energy transition,
• balancing and storage,
• climate-neutral end use & energy efficiency,
• and sustainable mobility.



Source: Smart Grid Roadmap Guidebook (EPRI, 2012)

Figure 1

Session 14:05 – 15:05
Demand response

Room: HSZ/0301
Chair: Jannis Eichenberg

Gas demand in times of crisis: Energy savings by consumer group in Germany

Oliver Ruhnau, *Hertie School Berlin*

The impact of demand-side mitigation measures in German passenger transport on the energy system transformation

Marlin Arnz, *Technische Universität Berlin*

The role of dynamic electricity price contracts to utilise residential demand-side response to fight the energy crisis and ease the transformation to a renewable power system

Matthias Hofmann, *NTNU / Statnett*

Gas demand in times of crisis: Energy savings by consumer group in Germany

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Keywords: energy demand, energy crisis, natural gas, demand response

Motivation

Russia curbed its natural gas supply to Europe in 2021 and 2022, creating a grave energy crisis. Since mid-2021, spot prices of natural gas have been on a steep rise, reaching levels of 100-200 €/MWh in 2022. This is about ten times the long-term pre-Covid price levels of 15-20 €/MWh. Average German residential retail prices increased substantially since January 2022, having more than doubled by October 2022. With domestic European gas supply being limited, Europe turned to liquified natural gas (LNG) as a substitute, but global LNG markets are tight, and European import terminal capacity is limited. As a result, reducing gas consumption has become key to European security of energy supply.

Methods

This paper empirically estimates the crisis response of natural gas consumers in Germany - for decades the largest export market for Russian gas. Using a multiple regression model, we estimate the response of small consumers, industry, and power stations separately, controlling for the non-linear temperature-heating relationship, seasonality, and trends. We also discuss the drivers behind consumption reductions and draw conclusions on their role in coping with the crisis.

Results

For industrial consumers, we find a strong and sustained response, with reductions steadily increasing from 4% in September 2021 to 29% in October 2022. For small consumers, including households and small enterprises, we find reductions between 10% and 42% from March to October 2022. Gas savings in the power sector are more volatile and not only driven by reduced Russian gas supply.

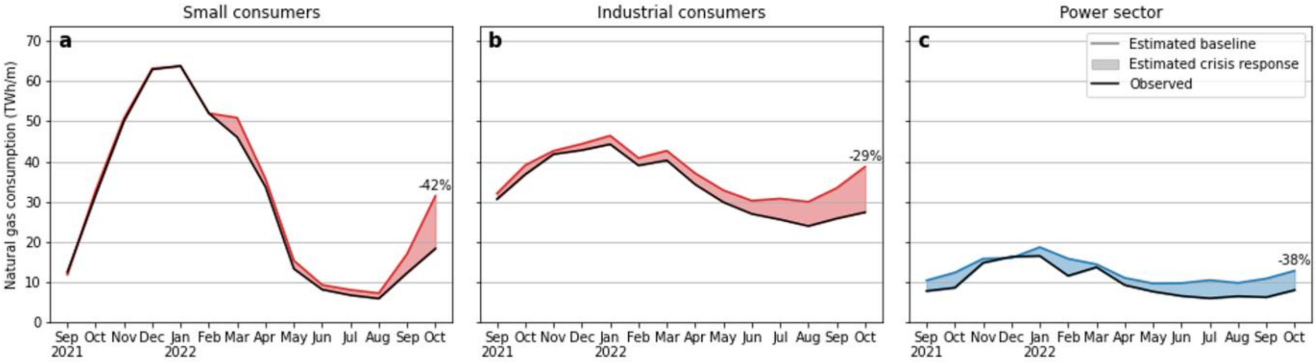
Small consumers
Industrial consumers
Power sector
a
b
c
Natural gas consumption (TWh/m)
70
60
50
40
30
20
10
0
-42%
-29%
-38%
Estimated baseline
Estimated crisis response
Observed
Sep 2021
Oct
Nov
Dec
Jan 2022
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct

Figure 1

The impact of demand-side mitigation measures in German passenger transport on the energy system transformation

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Keywords: transport, energy demand, sufficiency, energy system design, model coupling

Motivation

Achieving the climate targets of the Paris Agreements demands immediate and thorough action in decarbonising the world's energy systems. In passenger transport - one of the largest energy sectors - there are three prominent decarbonisation strategies: Avoiding unnecessary traffic, shifting traffic to more efficient modes, and improving transport technologies. While technological improvements have seen much attention in research and policy, the role of avoid and shift measures remains under-researched. However, the rigid time pressure requires simultaneous action in all fields to reduce transport's energy footprint - especially in high-income countries that consume over-proportionally much energy for mobility. We examine the case of Germany, where avoid and shift strategies play a minor role in past and current transport policy. At the same time, there is an ongoing political and scientific debate around the design of the carbon neutral energy system and its technologies, capacities, and flexibility. We pay special attention to the interplay between transport demand and energy system design and ask, "What is the effect of transport demand scenarios on the design of a renewable energy system?"

Methods

We aim to answer this question by coupling two quantitative models: The open source aggregated transport model quetzal_germany simulates the transport demand based on a multitude of technological, economic, organisational, cultural, and political drivers that affect the number, distance, and mode of trips from twelve demand segments. We feed this transport demand into an AnyMOD energy system model for Europe, where we fix other countries than Germany to the reference and analyse the effect of distinct transport demand scenarios: Avoiding as much traffic as possible, shifting as much traffic to public transport as possible, and the combination of both. These scenarios are created in a qualitative-quantitative research design that is suitable to investigate maximum sufficiency futures for German passenger transport: We first collected drivers towards sufficiency in an interdisciplinary expert workshop and utilised them to construct socio-technical storylines, using methods from transition theory. We then translated these drivers into transport model parameters and quantified them with an expert survey. We apply each of these demand scenarios for two different vehicle fleets in the energy model: The reference vehicle stock, as simulated in the Ariadne project, and the most efficient vehicle fleet with 100% battery-electric drivetrains. Finally, we analyse the impacts of transport system design on the cost optimal energy system design with 100% renewable energy sources in 2040.

Results

Our results span across three levels: the drivers of sufficiency scenarios for German passenger transport, their quantification with the transport model, and their impact on the energy system. The Avoid scenario is able to reduce the number of trips - especially long trips - by 38%, yielding a 52% reduction in final energy demand. Its main drivers are spatial planning that aims at reducing the necessity for trips and a significant cultural shift towards social cohesion, "from ownership to access", and local economies. The Shift scenario, on the other hand, does not affect mobility culture or the economic system, but features highly interconnected, reliable, and attractive public transport, fast and secure cycling networks, and minimum car dependency. It achieves a 42% modal share of public transport, which reduces the energy footprint by 27%. The maximum sufficiency scenario, Avoid+Shift, is able to reduce motorised individual traffic to 40% and thus, reducing passenger transport's energy demand by nearly three quarters. It shows a radical shift towards post-materialism and car disincentivising measures, while adding all developments of the other two scenarios. This has notable consequences for the energy system (which are subject for final refinements at this stage of the research project). We expect three kinds of results: The optimal electricity supply is significantly cheaper and the most expensive part of the energy system transformation - electric vehicles - decreases starkly; Shifts in electricity generation capacities across Europe and the dispense of non-European energy imports; Less battery capacities in the private vehicle fleet creates demand for stationary batteries and shifts the distribution of flexibility in the energy system. These results show how the effect of three classic mitigation strategies in passenger transport - Avoid, Shift, Improve - on the energy system and ambitious climate change mitigation goals.

The role of dynamic electricity price contracts to utilise residential demand-side response to fight the energy crisis and ease the transformation to a renewable power system

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Keywords: demand-side flexibility, demand response, price elasticity, real-time pricing, households

Motivation

As Europe strives to transform its electricity system and struggles with energy security challenges, the role of residential demand-side response becomes increasingly important. Here, flexible households can play a vital role in balancing renewable energy production if exposed to dynamic electricity prices reflecting the day-ahead market. In Norway, all end-users have smart meters, and ca. 75% of the households have a dynamic electricity price contracts tied to the hourly spot price. The energy crisis, and the significant increase in electricity prices starting in autumn 2021, provide a opportunity to study how Norwegian households have adjusted their electricity consumption according to the power system's needs, which are reflected in the spot prices. Dynamic price contracts with hourly prices incentivise both energy savings and peak demand reduction, and may be an effective instrument to achieve the electricity demand reduction targets that the EU agreed on: an overall reduction of 10%, and a 5% reduction in peak demand periods. Our research investigates the potential of dynamic electricity price contracts for enabling residential demand-side response during the energy crisis and an easier transformation to a renewable power system. By analysing real electricity consumption data from Norwegian households, we show how price differences affect consumer behaviour in the short and long term and, thus, the potential of residential implicit demand flexibility. We investigate in detail the following research questions. How fast did households react to the price increase and how much did they reduce their electricity consumption overall and in peak hours? What was the effect of various price levels and intraday price differences on the response? To what extent did variations in outdoor temperature and electrical heating impact the achieved energy savings? How did information about the intraday price variability and smart electrical vehicle charging affect peak reduction?

Methods

We collected the aggregated hourly electricity consumption data of all households within each of the five Norwegian bidding zones from June 2019 to July 2022, and individual demand data from 1,136 households from October 2020 to March 2022. The data was collected from smart meters installed at all end-users. Additionally, we conducted a survey among 4,446 households, including the households with electricity consumption data, to collect information on their demographic characteristics, appliances, power contracts, and their response to the exceptionally high electricity prices in winter 2021/22. Based on the survey answers, the individual demand data were seperated into various subgroups of interest, such as households with spot price contracts, price information app users, and end users with smart electric vehicle charging. The electricity consumption data were analysed with econometric models explaining the demand with various explanatory variables. Specifically, we employed variables that controlled for factors that influence the consumption pattern, such as outdoor temperature, holidays, the month of the year, the hour of the day, and COVID-19 measures by using the Oxford covid stringency indicator. Norwegian households' electricity consumption is highly temperature-dependent since electricity is the primary energy source for heating. The second set of explanatory variables encompasses daily activity patterns. The covid stringency indicator represents the probability of household members working in a home office and, thus, a change in the daily work pattern. We implemented the model in the statistical software R, used weighted least square based on the number of households in each bidding zone to estimate the model parameters, and conducted various diagnostic tests to ensure the validity of the model assumptions.

Results

The results show that households reduced their electricity consumption approximately one month after the start of the price increase in August 2021. This demand response resulted in an overall reduction in electricity consumption of 11%, and of 10% in peak hours during winter 2021/22 compared with the pre-crisis consumption. The price level, defined as the average daily spot price, seems to have a limited effect on the response since the households had a similar reduction in consumption regardless of the price level. An explanation for these results might be that the generally high electricity prices lead to a long-term change in the electricity consumption behaviour of the households, which is not affected by the daily variations in the price. Furthermore, the results indicate that a higher price difference between peak and off-peak hours leads to slightly higher demand reduction during the peak hours. Our results suggest that the achieved reduction in electricity consumption depends on the outside temperature due to a large share of households with electrical heating. The highest reduction results can be found between -10 and 0 °C. We see a higher reduction in peak hours from households that checked electricity prices via an app or similar tools several times a week.Furthermore, households with smart electric vehicle charging responded by shifting electricity consumption to the night hours with the lowest electricity prices. Thus, smart charging contributed to significantly higher reductions in peak hours. Overall, we find that households are flexible in their electricity demand. Our findings suggest that dynamic pricing contracts are an effective tool for utilising residential demand-side response, and such power contracts should be promoted to incentivize demand reductions in periods of energy shortage or to balance variable electricity production in the future.

Session 14:05 – 15:05
Renewables and infrastructure

Room: HSZ/0304
Chair: Mario Kendziorski

Potentials of parking and floating photovoltaics in Germany

Rachel Maier, *Forschungszentrum Jülich*

Solar prosumage: Interactions with the transmission grid

Mario Kendziorski, *Technische Universität Berlin*

Spaghettigrids: Offshore grid development with a geographical information system - First results for Baltic and North Sea

Felix Jakob Fliegner, *50 Hertz / Technische Universität Dresden*

Potentials of parking and floating photovoltaics in Germany

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Keywords: photovoltaics, potential, parking photovoltaics, floating photovoltaics

Motivation

In view of the current political situation and the energy crisis in Germany, the efforts to transform the energy system and thus reduce energy dependency are intensifying. In the future, renewable energies, especially wind power and photovoltaics, will play a central role and are currently the focus of regulatory changes. The current draft of the BMWK's photovoltaic strategy in March 2023 [1] aims to promote floating photovoltaics and parking photovoltaics, among other measures. In contrast to open-field photovoltaics on non-sealed, green areas, there are only few studies assessing future potentials for floating photovoltaics and parking photovoltaics in Germany. To the author's knowledge, only Fraunhofer ISE estimates Germany-wide potentials, but with little description of the used methods and no regionalized results. Their studies conclude a technical potential of 44 GWp [2] and an economic potential of 2.74 GW [3] for floating photovoltaics and a parking photovoltaics potential of 59 GWp [2]. For floating and parking photovoltaic, there are currently no nationwide potential analyses with detailed methodology and regionalized results.

Methods

Land eligibility analyses are carried out to determine the potential for floating and parking photovoltaics in Germany. For this, the tool TREP [3] based on GLAES [4] and detailed geographic data sets are used. For parking photovoltaics, the minimum number of parking spaces for obligatory construction on new parking lots varies between 35 and 100 for federal states with relevant legislation [5]. In the following, the parking photovoltaics potential is determined nationwide on parking lots with more than 35 parking spaces, assuming construction only on the parking spaces within the parking lot. As the information about the number of parking spaces in parking lots is rarely available, an extract of Open Street Map (OSM) data [6] containing this information is used to analyze the area of parking lots with 35 parking spaces and the area percentage of parking spaces in the parking lots. These factors are used to calculate the area potential for all parking lots in Germany with the minimum size of the determined area for 35 parking spaces and with the help of the determined area share of the parking spaces. For floating photovoltaics, artificial and heavily modified lakes are identified [7] and unusable areas, such as protected areas, are excluded. Then, a share of 15% is assumed usable for floating photovoltaics, which is in line with current legislation [1]. Finally, the area potentials for floating and parking photovoltaics can be converted into a capacity potential by capacity density factors. [3] Risch, Maier et al. „Potentials of Renewable Energy Sources in Germany and the Influence of Land Use Datasets“. Energies 15 (30.7.2022).

Results

In the planed contribution, preliminary results for the capacity potential analyses of floating photovoltaics and parking photovoltaics are presented. The scenarios are aligned with the development of current legislations. The site-specific resolution allows a regionalization of the results. The potential of parking photovoltaics in Germany is 23.2 GW (national distribution is shown in figure 1). The capacity potential varies between the federal states from 200.7 MW for Bremen to 4.7 GW for North Rhine-Westphalia. The result is significantly lower than that of the Fraunhofer ISE study. Future work could analyze the sensitivity to the minimum count of parking spaces in parking lots for constructing parking photovoltaics or the sensitivity to the area share of parking photovoltaics in the parking lots. The potential of floating photovoltaics for Germany is 4.3 GW (national distribution is shown in figure 2). The states of Bremen, Saarland, and Mecklenburg-Vorpommern have no potential, while Saxony-Anhalt has the largest potential with 1.1 GW. This can be explained by the high number of artificial and heavily modified lakes in Saxony-Anhalt. The results are between the economic and technical potentials from the Fraunhofer ISE study. In future, the scenario for floating photovoltaics can be improved by also considering other regulatory constraints, such as a 40-meter buffer to the shore [1], or analyzing the sensitivity of the results towards factors, such as the area share. Differences in national potential for parking and floating PV could be due to different methods, data sets or used factors, such as usable area share or capacity density. However, due to missing documentation of used methods, these are not comparable.

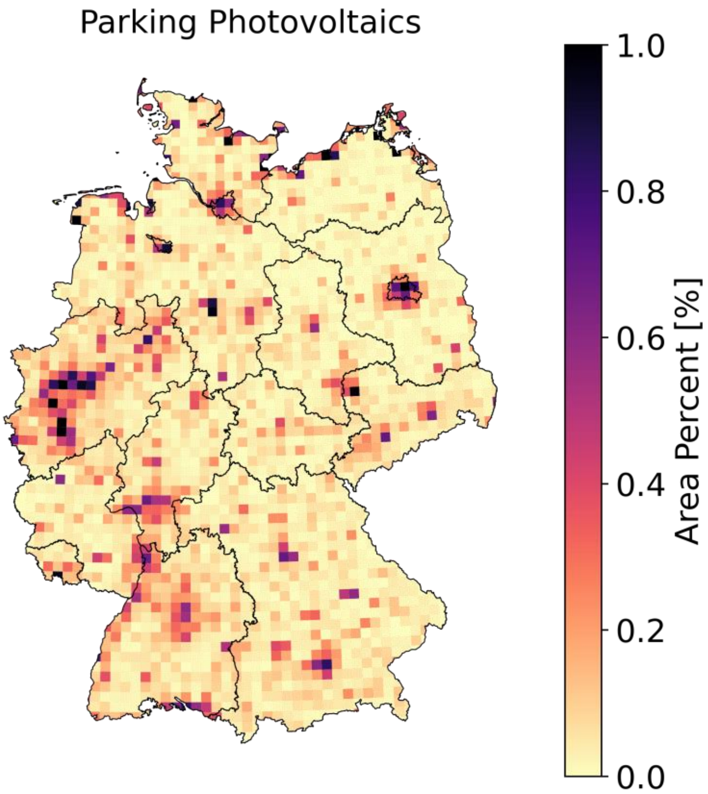

Figure 1

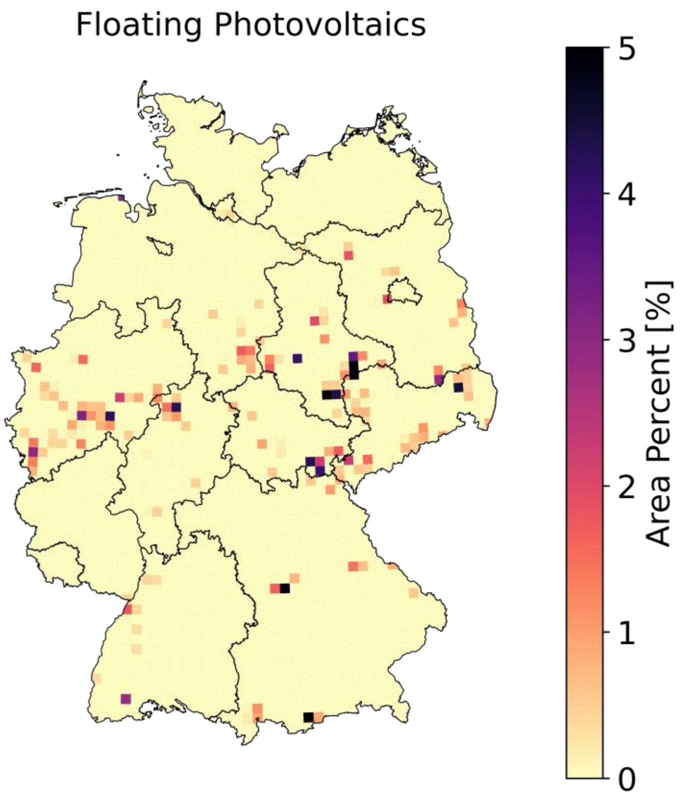

Figure 2

[1] *Bundesministerium für Wirtschaft und Klimaschutz. „Photovoltaik-Strategie". März 2023. https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/photovoltaik-stategie-2023.pdf?__blob=publicationFile&v=6.*

[2] *Wirth, Harry. „Aktuelle Fakten zur Photovoltaik in Deutschland". Freiburg: Fraunhofer-Institut für Solare Energiesysteme ISE, 1.03.2023. https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/aktuelle-fakten-zur-photovoltaik-in-deutschland.pdf.*

[3] *Fraunhofer-Institut für Solare Energiesysteme ISE. „Fraunhofer ISE analysiert Potenzial für Solarkraftwerke auf Braunkohle-Tagebauseen", 3.02.2020. https://www.ise.fraunhofer.de/de/presse-und-medien/presseinformationen/2020/fraunhofer-ise-analysiert-potenzial-fuer-solarkraftwerke-auf-braunkohle-tagebauseen.html.*

[4] *Ryberg et al. „Evaluating Land Eligibility Constraints of Renewable Energy Sources in Europe". Energies 11 (14.5.2018).*

[5] *Kühl, Andreas. „Photovoltaik für Parkplätze und Garagen", 2.2.2023.*

[6] *OpenStreetMap contributors. „Open Street Map", 2021.*

[7] *WasserBLIcK/BfG und Zuständige Behörden der Länder. „Wasserkörper-DE", 2020.*

Solar prosumage: Interactions with the transmission grid

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Keywords: prosumage, electricity market modeling, transmission grid, linear optimization, tariff design

Motivation

In many electricity markets, an increasing number of consumers are engaging in decentralized self-generation of solar electricity. Often coupled with battery storage, this phenomenon is referred to as solar prosumage. While the effects of solar prosumage on other generation and storage capacities in the power sector have been analyzed before, its interactions with the transmission grid are not yet fully understood. Concepts involving decentralized generators, such as prosumage, are viewed by some authors as a risk for higher system costs, since economic self-interest may counteract cost-efficient market outcomes. In this study, we combine two open-source energy models, DIETER and POMATO, in a three-stage modeling framework to quantitatively illustrate potential effects on future scenarios of the German power sector. In our analysis, we specifically examine the impact of prosumage on power flows within the transmission grid.

Methods

First, we use the transmission system model POMATO to generate wholesale price time series for mid-term future scenarios in Germany by solving linear dispatch and redispatch optimization problems. POMATO, an open-source Power Market Tool, facilitates research on interconnected modern and future electricity markets in the context of the physical transmission system. It solves a multi-step electricity market model, including zonal market clearing with subsequent redispatch. The resulting wholesale price time series serve as input for the prosumage module of the capacity expansion planning model. This module derives optimal prosumage investment and dispatch decisions for alternative future tariff design assumptions for individual households at each node of the transmission grid. We simulate different pricing mechanisms, such as nodal and zonal pricing, as well as real-time pricing. In the final step, the repercussions of prosumage decisions on the transmission grid are evaluated using POMATO once more. The models provide a high level of temporal and spatial detail by modeling all hours of a full year for all nodes of the German transmission grid.

Results

Preliminary results show that investments in prosumage are highly sensitive to future tariff design assumptions. Retail tariff designs with higher volumetric components lead to higher investments in prosumage compared to tariff designs with higher fixed parts. Nodal and real-time-pricing schemes tend to reveal more grid feasible market results that mitigate congestion but need to be further investigated. Nodal pricing schemes take into account the transmission costs and hence lead to dispatch decisions by prosumagers that efficiently use transmission lines. Real-time-pricing schemes lower the power feedin to the grid in times of high renewables availability and power withdrawal from the grid in times of low renewables availability, which minimizes nodal grid injections and relieves transmission lines. Our paper gives insights into the role of prosumage for the electricity system and the transmission grid for future mid-term scenarios of the German electricity sector. Preliminary results lead us to the following conclusions: Effects of prosumage on the transmission system and the electricity market depend on the tariff design. Higher fixed tariff components as well as spatially and temporally invariant pricing schemes lead to lower investments in prosumage.

Spaghettigrids: Offshore grid development with a geographical information system - First results for Baltic and North Sea

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Keywords: offshore grid, energy system modelling, maritime spatial planning, geographical information system

Motivation

On the roadmap to reach the climate targets, Europe is committed to increase offshore wind power generation substantially from today towards 2050. This raises the question, what infrastructure layout efficiently integrates offshore wind power into the transmission grid. It is commonly approached via search graphs that contain possible expansion candidates to benchmark grid topology layouts such as radial connections of wind farms, multi terminal offshore hubs or hybrid interconnectors. In order to keep computational tractable, such search graphs are often created manually and at a low resolution with only few nodes, i.e. neglecting the geographic reality of land cover and competing spacious maritime activities. With a stark increase in the number of wind farms, a low resolution might overlook cannibalisation and synergy potentials in quantitative studies that try to distinguish (close to) optimal solutions from each other. Besides, additional constraints, such as limited space for transmission cables at sea and hosting capacity for individual substations ashore cannot be considered. The purpose of this work is to introduce a novel methodology that creates a high resolution search graph for quantitative analysis on transmission capacity expansion at sea. The objective of such a setup is to leverage spatial domain knowledge, while maintaining computational complexity and obtained solution accuracy within acceptable limits. High resolution search graphs allow early stage assessments to reflect on the impact of sensitive parameters such as choice of transmission assets and costs. When search graphs are setup analytically, the process of scenario building becomes more transparent and reproducible, which can facilitate strategic decision making on the basis of quantitative analysis. An analytic search graph setup also speeds up the process, which allows it to evolve from a "case-by-case, one-at-a-time" notion to a holistic network planning.

Methods

A search graph denotes the set of candidate links an optimiser can choose to invest in, to increase transmission capacities between nodes. In order to create a search graph bottom-up, a geographical information system (GIS) is setup in QGIS. It is used to (1) consolidate the required input data (such as maritime spatial planning, existing infrastructure and land cover), (2) allocate points, (3) create links and (4) apply a complexity reduction. Point allocation is a virtual computation help that allocates potential future wind farm points and potential candidates of offshore hubs (i.e. clusters of several offshore wind farms in a given neighbourhood) into the sea. It enables a forward looking analysis on a not yet existing offshore grid. The result is a quantitative estimation on the localisation of future wind power capacity in the sea, being consistent with the spatial planning reality and top-down capacity targets (either user defined or politically derived). In other words, a possible scenario for the future offshore wind farm build out in a given region is obtained. The purpose of link creation is to complete the search graph. By mathematical terms, the previously allocated points describe the nodes of this graph and the links describe adjacency relationships among them. Two nodes are called adjacent if a feasible link can be found in GIS to connect both with each other. The feasibility assessment is implemented as a multi criteria analysis, where for each pair of nodes in question, a least-cost path is searched for in a penalty cost raster of maritime "obstacles" (such as nature protection, land cover or otherwise designated areas).

Results

At the case of Baltic and North Sea the workflow is demonstrated. It is found that respecting the geographic reality of the heavily managed sea space de-risks future offshore projects for more accurate cost estimates. On average, the routed paths obtained with the GIS analysis return length offsets of 20 to 30 percent, compared to straight radial links, which is a considerable delta for the capital expenditure intensive investment optimisation of transmission links at sea. The consideration of designation areas in the sea also consolidates future grid planning options into common paths of transition, which facilitates the identification of relevant scenarios for analysis. In addition, it can be shown, that the commonly chosen benchmark of an "all radial" connection of wind farms to shore (i.e. each wind farm with an individual transmission cable to the nearest national substation) is a questionable choice for its unprecedented concentration of landing capacity and transmission corridor widths. While the "true" societal value of bundled transmission paths and hubs can only be calculated via subsequent market and grid simulations, this analysis may provide important contributions to the scenario building and model calibration phase of a quantitative study on the offshore grid of the future. It can also create a link to other sectors and energy carriers in forthcoming extensions. The identification of offshore sites for hydrogen electrolysis or carbon dioxide sequestration are of strategic relevance for many countries as well and can be interpreted as another layer in the GIS. Ultimately, optimising the next generation offshore grid in Europe is a quest of international scale. For the ramp up generation capacities in an already intensively managed sea space, the rationale for high-resolution modelling is apparent. The means of geo information science can contribute to this quest in aggregating complex spatial data into tractable search graphs for subsequent analysis.

Session 15:30 – 17:00
Energy system modeling IV

Room: HSZ/0004, hybrid
Chair: Constantin Dierstein

How reduction of energy demand can help to reach or reinforce German mitigation targets
Patrick Jürgens, *Fraunhofer ISE*

The industry transformation from fossil fuels to hydrogen will reorganize value chains: Big picture and case studies for Germany
Nima Farhang-Damghani, *FAU Erlangen-Nürnberg*

Coherent transformation paths in energy system modelling - A case study for Germany
Toni Busch, *Forschungszentrum Jülich*

At the borderline: An analysis of the electricity trade between Mexico and US (online)
Lilia Garcia Manrique, *University of Sussex*

How reduction of energy demand can help to reach or reinforce German mitigation targets

Patrick Jürgens[1]

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Keywords: energy system analysis, modelling, climate mitigation, energy transition, sufficiency

Motivation

There are multiple recent studies analysing the German energy transformation considering its national CO2 reduction goals, i.e. with the target of net-zero emissions in 2045. However, the national mitigation targets announced by the signing states of the Paris agreement are not sufficient to limit global warming to 1.5°C and more ambitious mitigation targets are needed. Additionally, even for reaching the mitigation targets from the German climate law, LCA studies indicate that we might reach critical points of supply for specific resources [1]. A recent report of Acatech highlights the importance of reduction of energy demand to reach the German climate goals or to reinforce the mitigation targets to close the worldwide ambition gap [2]. We further deepen the analysis on which role the reduction of energy demand by a change of lifestyle can play to either reduce pressure on resource supply or reinforce mitigation targets.

[1] T. Naegler et al.,'Life cycle-based environmental impacts of energy system transformation strategies for Germany: Are climate and environmental protection conflicting goals?', Energy Reports, vol. 8, pp. 4763-4775, Nov. 2022, doi: 10.1016/j.egyr.2022.03.143.

[2] acatech,'Technologieumbau, Suffizienz und negative Emissionen', Feb. 02, 2023. https://www.acatech.de/allgemein/transformationspfade/ (accessed Feb. 22, 2023).

Methods

The German energy system model REMod was developed at the Fraunhofer Institute for Solar Energy Systems to model transformation pathways of the German energy system within a given CO2 reduction pathway. REMod uses a mixture of simulation and optimization: it simulates the operation of the energy system and optimizes the accumulated costs of the transformation pathway with an evolutionary optimization method (CMA-ES). The focus of REMod is the detailed description of sector coupling, i.e. the use of renewable energies in the demand sectors industry, buildings and transportation including interactions between these sectors. By simulating all sectors of the energy system on an hourly basis from today to 2050 considering five years with differing meteorological conditions, the model ensures that the energy demand is always met and supply reliability is guaranteed. The optimization determines yearly additions in the available capacity for multiple power plant types and energy conversion technologies as well as exchange of technologies in the demand sectors. Thus, the optimization enables a cost optimal transformation path of the entire energy system by optimizing the installed capacities (e.g. of renewable energies or power plants) and market shares (e.g. of driving and heating technologies). The approach of simultaneously simulating and optimizing all sectors of the energy system distinguishes REMod from other energy system models and enables the analysis of mutual influences of the different sectors. Modelling of different scenarios is done by restricting CO2 emissions to a budget along the transition pathway. By setting further parameters like minimal and maximal yearly capacity additions in the supply sector and market shares in the demand sectors different technological foci or societal trends can be analysed. In this work the interplay between simulation and optimization is used to analyse the effect that reduction of energy demand can have on the energy system.

Results

Three scenarios are created:

• “reference”: the transformation path of the energy system is optimized based on predicted energy demand. The CO2-budget is set to reach the German climate targets.

• “reduced demand”: the transformation path is optimized based on reduction of energy demand. The CO2-budget is also set to reach the German climate targets, so reduction of energy demand leads to savings of resources for the transformation of the energy system.

• “reinforce mitigation: the transformation pathway of the “reference” scenario is simulated with a reduction of energy demand.

This leads to a reduction of CO2 emissions while keeping the ambitions of the transformation of the energy system at the same level. Preliminary results show that a reduction of energy demand under the current CO2-mitigation-path (“reduced demand”) reduces the need of installed renewable capacity (wind and solar) by 200-300 GW. It also reduces pressure on the transformation in the demand sectors. In the industry sector, the use of hydrogen is minimised, in the buildings sector the phase out of gas boilers can happen at a lower pace and renovation rates can be smaller and in the transportation sector the phase in of battery electric vehicles can be delayed and overall number of electric vehicles decline compared to the “reference” scenario without reduction of energy demand. Preliminary results of the “reinforce mitigation” scenario show that overall CO2 emissions can be reduced by 700 MtCO2 in the years from 2020 until reaching net zero emissions in 2045. The reduction of CO2-emissions is induced by a reduction of use of fossil fuels, i.e. 500 TWh of natural gas, 2300 TWh of oil and 40 TWh of coal from 2020 to 2045. Furthermore, reduction of energy consumption also leads to a reduction of synthetic, CO_2 neutral imports, namely 40 TWh of hydrogen, 540 TWh synthetic gas and 230 TWh eFuels. The electricity imports also decrease by 360 TWh, while electricity exports increase by 250 TWh.

Table 1
Assumed reduction of energy services in different use areas from 2020 to 2045.

Use area	Reduction of energy services
private transportation	47%
road freight transport	40%
combustibles for rail	100%
aviation and navigation	60%
space heating	10%
industrial process heat	33%
classical power applications	45%

Table 1

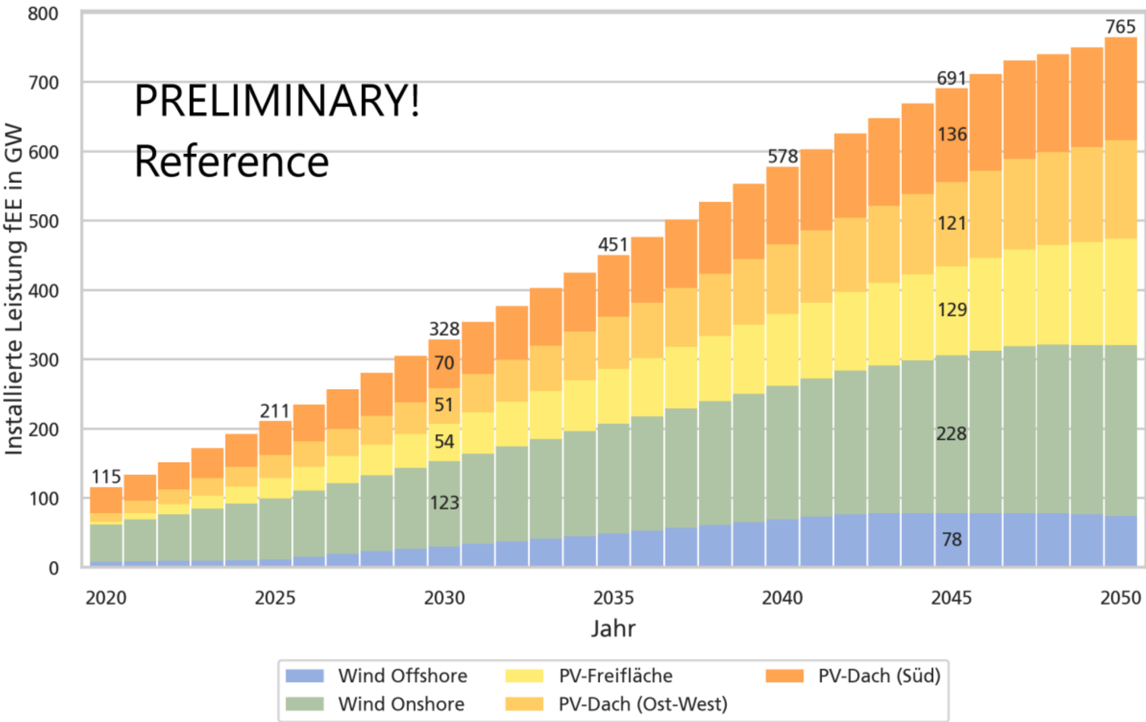

Figure 1

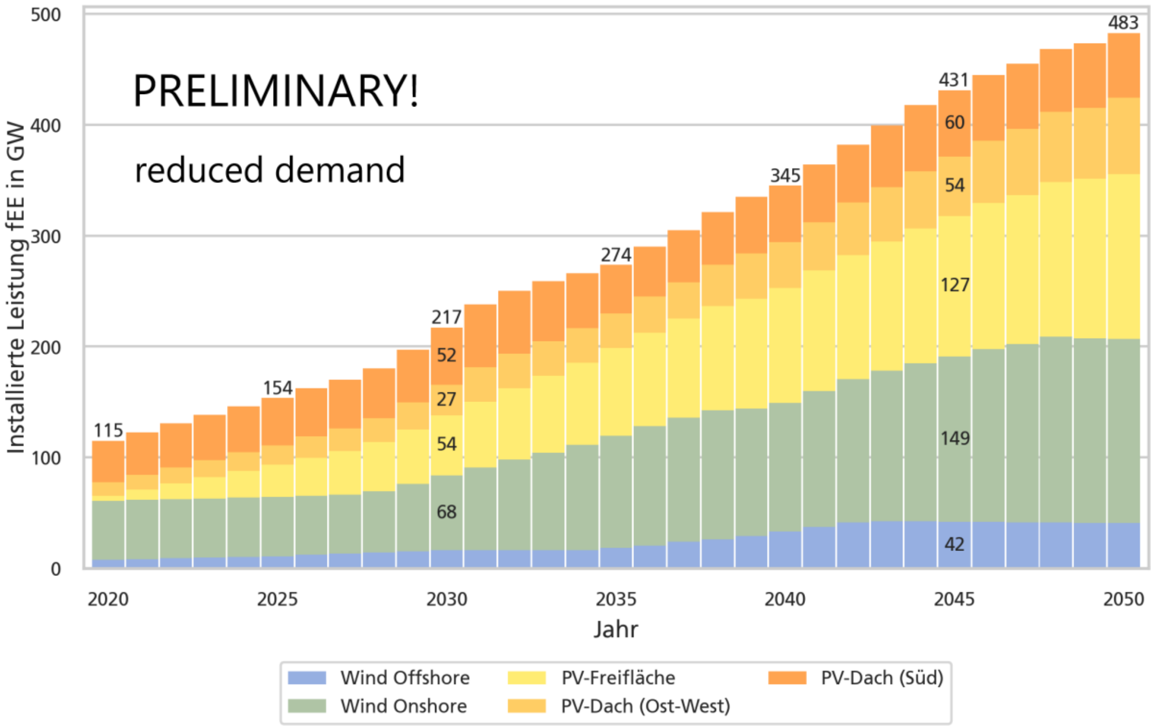
PRELIMINARY!
reduced demand
Installierte Leistung fEE in GW
500
400
300
200
100
0
115
154
217
52
27
54
68
274
345
431
60
54
127
149
42
483
2020
2025
2030
2035
2040
2045
2050
Jahr
Wind Offshore
Wind Onshore
PV-Freifläche
PV-Dach (Ost-West)
PV-Dach (Süd)

Figure 2

The industry transformation from fossil fuels to hydrogen will reorganize value chains: Big picture and case studies for Germany

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Keywords: hydrogen, energy-intensive industry, industrial transformation, hydrogen-based industrial value chains, demand

Motivation

In the future, low-carbon hydrogen will be needed to replace fossil hydrogen in the chemical industry and for the sustainable transformation of production processes, e.g., as feedstock and energy carrier in the steel industry or as energy carrier in the mineral, glass, and pulp and paper industry. Since it is unlikely possible and economical to provide locally produced low-carbon hydrogen as an input factor in Germany within the necessary time window, hydrogen production and possibly further process steps are likely to be substituted by imports from regions with excellent conditions for renewable energies worldwide. Two aspects are important in this context: First, the decision in different industries whether to defossilize production processes using low-carbon hydrogen or based on electrification; second, whether to do so at the current location of a firm's production facilities or by relocating part of the value chain to regions with more favorable renewable energy supply. In this paper, we address those questions by providing an overview of possible hydrogen demand in key energy intensive industries in Germany, followed by case studies for specific production processes in the steel and the chemical industry. The general overview provides insights on energy demand and emissions in today's industry processes in Germany in order to then develop an upper and lower demand scenario for future hydrogen usage. Based on this first step, we assess the advantages of relocating parts of the value chains abroad. Germany is well suited for such case studies due to its strong industrial sector and its ambitious climate targets, i.e., its reduction pathway to 2030 and climate neutrality as early as 2045.

Methods

For the bottom-up calculation of the lower and upper limits of industrial hydrogen demand we carried out a literature review regarding the production outputs, capacities, emissions as well as fuel and energy consumption and demand for each relevant energy-intensive sector. After estimating a specific hydrogen consumption for each process, we come to conclusions by our literature review how each sector may utilize hydrogen and to what degree to constitute a lower and higher limit of demand. The lower limit constitutes a hydrogen utilization in sectors where it is exclusively necessary as a feedstock and for energetic use hydrogen will only play a supporting role. On the other hand, the upper limit constitutes, that hydrogen would play a more prominent role as a feedstock and for energetic use. For the analysis of the value chain costs we used a linear optimization model in the General Algebraic Modeling System (GAMS) environment. The objective was to minimize the sum of annual total cost of the whole supply chains for the production of steel, urea and ethylene through the intermediate products direct-reduced iron, ammonia and methanol. We compare 4 scenarios for each end product (steel, urea, ethylene). We compare the "Excellent site scenario" and the "Germany scenario" where each value chain and their respective intermediate products are only produced either in an excellent site with favorable renewable energy conditions and subsequent export of the end product to Germany or alternatively where the whole value chain remains in Germany. Another scenario in between sees the production of hydrogen in the excellent location and its transport to Germany, while the remaining value chain steps are carried out in Germany. The last scenario not only sees production of hydrogen in an excellent site but also the first intermediate product (iron, ammonia, methanol) while the last conversion step to steel, urea or methanol happens in Germany.

Results

In our bottom-up analysis for industrial hydrogen demand in Germany we show, that the demand for a climate-neutral industry would amount to between 197 TWh and 298 TWh which would be a great increase from the 55 TWh hydrogen consumed in Germany today. This is largely thanks to the increased use of hydrogen as a feedstock in the steel industry and the chemical industry, especially for methanol and ammonia production. The large increase in hydrogen demand for methanol production is also thanks to the future production of organic chemicals by methanol instead of naphtha from crude oil as it is currently. The highest hydrogen demand for energetic (heating) use only amounts to 57 TWh mainly in the cement, lime, glass and paper industry. For the value chain costs we show that especially the production of ethylene and urea through methanol and ammonia respectively have large cost differences between a complete production abroad versus the total value chain remaining Germany. Reason is largely because of their large dependency on hydrogen and thus renewable energy which are much cheaper in favorable regions with good PV and wind conditions. For the production of steel, the difference is rather marginal because the transformation of the steel industry to sustainable production is more capital cost intensive. Ultimately, the actual hydrogen demand for each sector will depend on whether the respective companies decide to run their climate-neutral production in Germany or relocate (parts of) the value chain abroad due to cost advantages. In addition to comparative costs, however, the availability of hydrogen and hydrogen transport infrastructure in Germany will play a key role in decision-making. Even if sufficient production of hydrogen in Europe at competitive prices is not possible in the long term, a timely ramp-up of production may be appropriate.

Coherent transformation paths in energy system modelling - A case study for Germany

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Keywords: energy system modeling, transformation path, climate neutrality, hydrogen infrastructure

Motivation

With the revised Climate Change Act (KSG) passed in 2021 by the Federal Government, Germany pledges to achieve climate neutrality by the year 2045. The energy system of the future will differ a lot from today's: Due to the high level of renewable energy sources used, energy production and demand are less likely to coincide neither on a temporal nor on a spatial scale. Furthermore, sector coupling gains importance in the process of decarbonizing the energy system. To provide answers of how this energy system transformation will take place, comprehensive energy system models are needed. Several renowned institutions have compiled studies of a climate neutral energy system in Germany by 2045 ("Big 5": Agora Energiewende/prognos (Klimaneutrales Deutschland 2045), dena/ewi (dena-Leitstudie), Fraunhofer ISI (Langfristszenarien), DBI/BCG (Klimapfade 2.0), PIK (Ariadne-Report)). These studies base on comprehensive models but mostly lack detailed spatially resolved analysis of transmission infrastructures. Therefore, the Institute for Techno-economic Systems Analysis (IEK-3) at the Forschungszentrum Jülich GmbH developed the model suit ETHOS. ETHOS incorporates integrated energy system models with high technological and spatial resolution. This study presents the expansion of the existing mode suit to allow the generation of consistent transformation paths. Among others, the new model allows determining the economically optimal placement of renewable energy sources, electrolysis sites and future hydrogen transmission grids consistently between 2020 and 2045. The latter is where the focus of this study lies. The basis for this analysis is a net CO2 neutral energy system in accordance with the KSG act presented in the IEK-3 study "New targets using old pathways?" (Stolten et al. 2022.).

Methods

To achieve a high level of technological, spatial, and temporal resolution the ETHOS model suit facilitates a model coupling approach: Within ETHOS, a single-region (ETHOS.NESTOR) and a multi-region energy system model (ETHOS.Infrastructure) are soft linked. The single-region model has high sectoral coverage, the multi-regional model high spatial resolution (80 regions), both are hourly resolved. In the model coupling approach, selected results of the single-region model are used as inputs for the multi region energy system model. These include the quantity of imported hydrogen, spatially resolved energy demands and the total amount of installed capacities of certain energy sources and conversion technologies (e.g., PV, Wind, Electrolyzers). The process is visualized in figure 1. The focus of this study lies on the multi-region model. Its main purpose related to this study is to determine the optimal spatial distribution of renewable energy sources (in accordance with a previous potential analysis) and conversion technologies (electrolyzers) as well as the routing, dimensioning and operation of transmission components (for hydrogen, electricity, and methane) using a linear programming approach. Special focus and contribution of this study is the implementation of infrastructure development across a transformation path (2020-2045, five-year steps) in a spatially resolved energy system. The authors added the functionality to inherit built infrastructures between milestone years, as shown in figure 2. After optimizing the design and operation of the first year, the optimal capacity values for every technology and every region are transferred to the next milestone year until the lifetime of this component is exceeded, and it gets decommissioned. This approach is compared to a single year optimization approach, where a standalone optimization is carried out for every milestone year without any linkage between the periods.

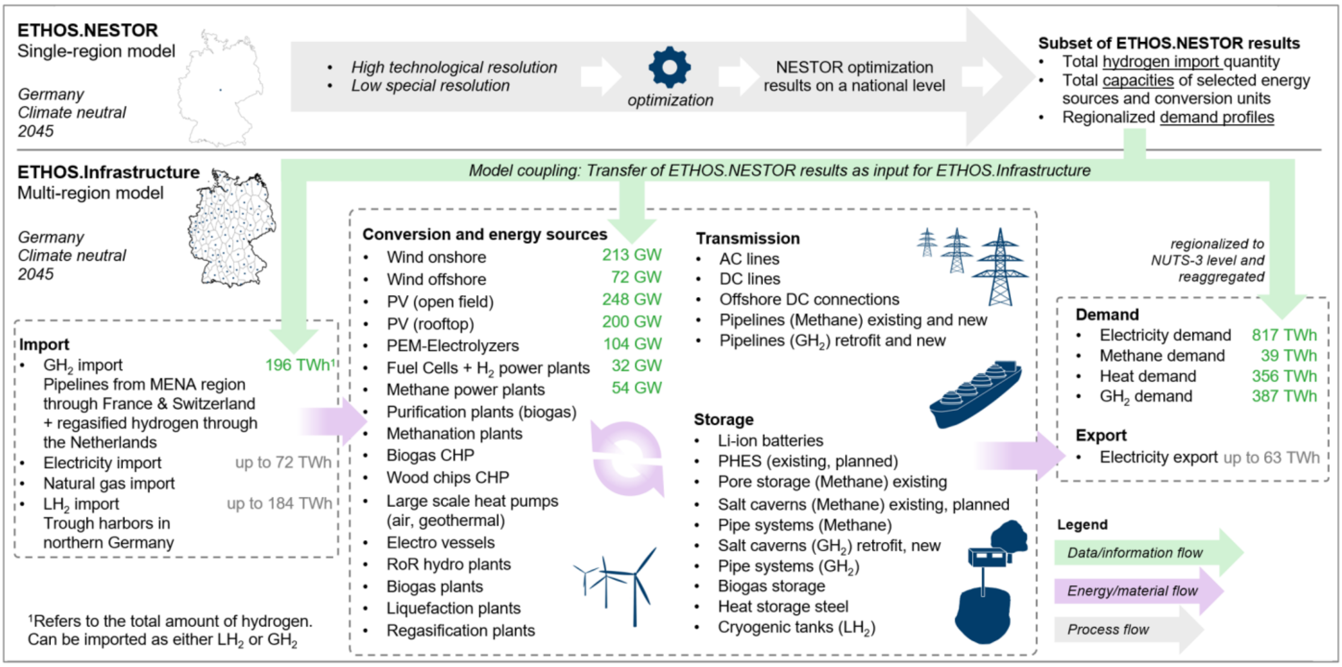

Figure 1: Schematic visualization of the model coupling process between the single-region and multi-region model for the year 2045.

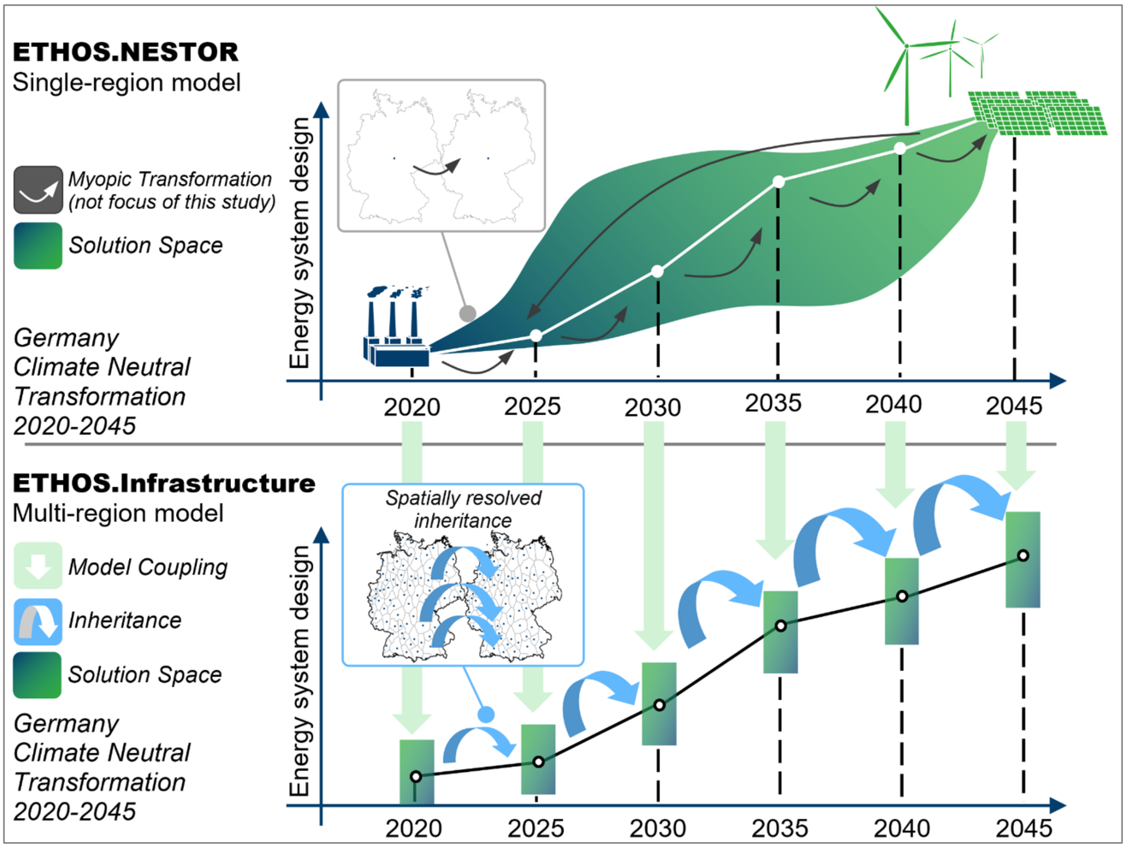

Figure 2: Schematic visualization of the model coupling and inheritance approach in the ETHOS model suit.

Results

The results show that hydrogen infrastructures play a significant role in the system transformation. By 2045 about 400 TWh (12 Mt) of hydrogen in total are imported and produced in Germany. It is used to serve hydrogen demands in the sectors of industry, transportation, buildings and in the energy sector itself. First hydrogen grids are developed in 2025. By 2045 the optimized hydrogen grid has a length of 16.355 km with an average pipeline capacity of 3 GW. The grid typology is determined by North to South-West (for domestically produced hydrogen) and by South to North/East (for imported hydrogen) connections. Most pipelines are retrofitted natural gas pipelines. Newly built pipelines become part of the optimal solution by 2045. They are used to extend the transportation capacity of imported hydrogen between the interconnector in Saarland and high industrial demand in North Rhine-Westphalia. Figure 3 shows how the inheritance approach provides a continuous transformation path. In the non-inheritance approach the cohesion between the milestone years is not given and infrastructures built in one period would not be part of the optimal solution in the following one. This shows that a single year optimization is not ideal for developing a coherent transformation path. On the other hand, this approach offers insights at how specific measures are cost-effective in intermediate years but are not included in following or target period solution. Furthermore, from a modeling standpoint it offers faster results as the models for the six milestone years can be optimized in parallel in contrast to the sequential calculation of the inheritance approach, where every optimization depends on the results of the previous period. As renewable energies, sector coupling and grid development are strongly interconnected, energy system planning becomes more complex. With its comprehensive, integrated, and cohesive energy system models ETHOS can provide answers to these pressing questions.

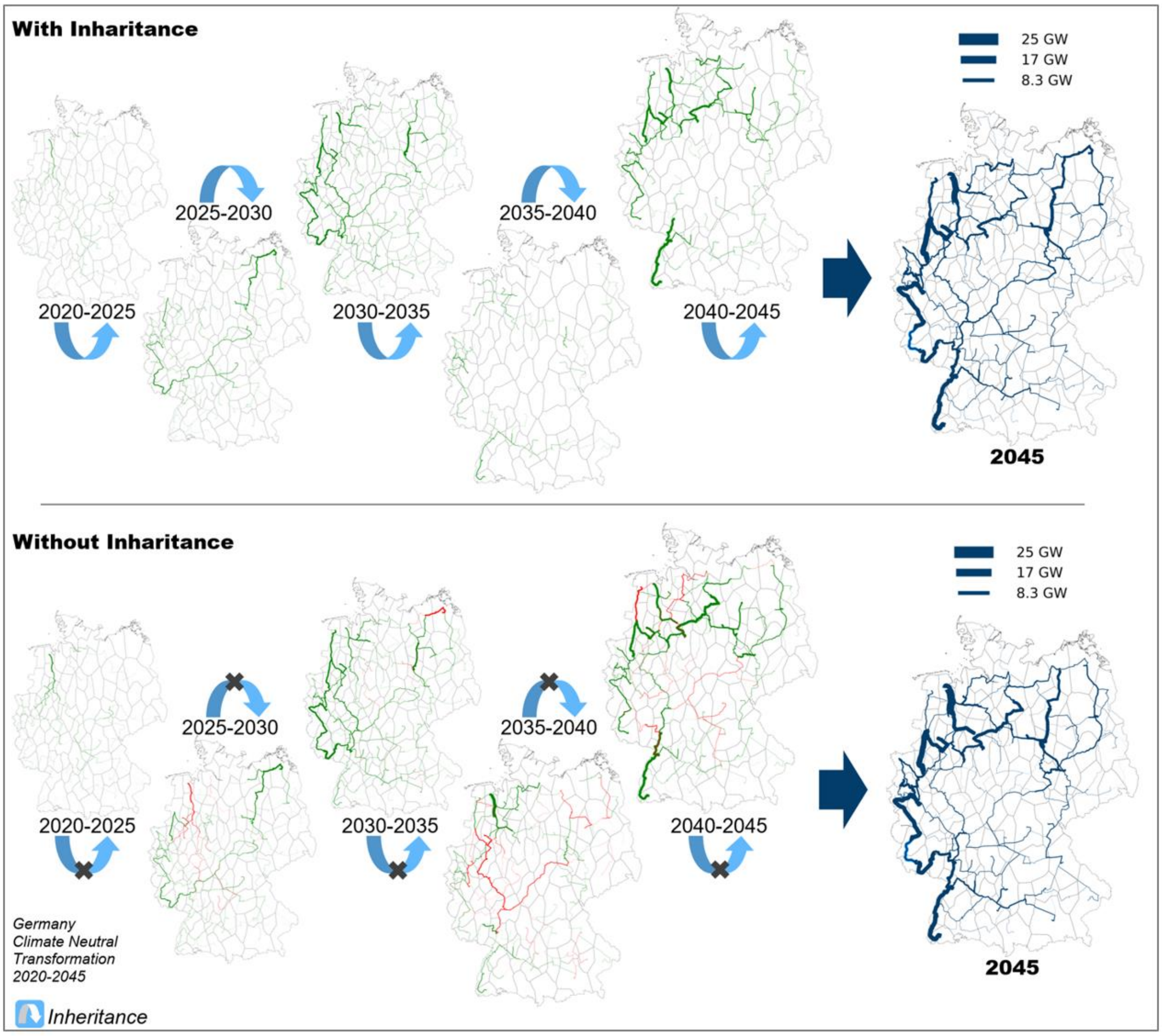

Figure 3: Positive (green) and negative (red) change in hydrogen pipeline capacity between the milestone years (left) and hydrogen grid in the target year 2045 (blue, right) for an energy system model with (upper) and without (lower) inheritance of infrastructures.

At the borderline: An analysis of the electricity trade between Mexico and US (online)

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Keywords: electricity markets, spatial econometrics, electricity trade, energy reform

Motivation

Electricity has been traded between Mexico and the United States since 1905 (Administration, 2013). It has increased since the North America Free Trade Agreement (NAFTA) was signed in 1994. The low volume of trade between the US and Mexico and the low level of transmission capacity can be explained by the low population density on the Mexican side of the border (Info, 2017). Before 2016, the Mexican electricity market was a government monopoly. The wholesale market is now open to private generators. Although small, the Mexican power market is profitable for US investors as electricity prices in Mexico are higher than in the US (Vidangos et al., 2016). Nevertheless, electricity trade between Mexico and USA represents an important opportunity for both countries. Since the Mexican Energy Reform, there have been relevant proposals for new interconnections on the border. One of the most relevant is a proposed interconnector between Arizona and Sonora. This new interconnection may represent lower prices for Mexico and a significant economic opportunity for the USA. For Mexico, it also represents an economic opportunity. In the border area, there are industrial clusters. Alvarez and Valencia (2016) demonstrate that one standard deviation reduction in electricity prices for industrial firms increases manufacturing output by 2.8%, an increase of 0.6% in real GDP. Research on electricity trade at the border is centered mainly on interconnector prices, particularly in the European Union, where electricity markets are mature and have sustained transmission capacities (Jamasb & Pollitt, 2005; Newbery et al., 2016; Ringler et al., 2017). There is no relevant research on Mexico and the USA. The present study analyses the effect of interconnectors on the Mexican Electric System, particularly the wholesale price. The question is whether the lower electricity prices in the US translate into a lower price for Mexico when it imports electricity.

Methods

Local marginal prices have a strong spatial component. Each price represents the marginal cost at a specific location and time. Congestion and loss costs are the spatial components of prices. They signal transmission constraints at each node at a particular hour. The spatial interdependence of the grid is such that a change in load at any node will affect the flow in all transmission loads due to Kirchhoff's Law. This implies that a price change at one node changes prices at all other nodes. As spatial information is contained in LMPs and prices are locally correlated, spatial econometric techniques are needed to analyze them. I am not using an exogenous interaction term; therefore, I include a correlated error term. This term reflects spillovers and unexpected fluctuations affecting their neighbor. If the model considers global spillovers, the coefficient of the spatial lag error term has an opposite sign from the global spillover effect (Kopczewska et al., 2017). Although the main behavior of the grid is global, there will be local effects determined by physical and operative restrictions. These reflect congestion and loss costs. Baja California reports low congestion costs with less volatile prices (International, 2018); therefore, it is more suitable to include a spatial lag error term instead of a Durbin component. The spatial autoregressive combined model (SAC) includes a spatial lag of the dependent variable Wy and a spatial lag error term We.

Results

Results show that interconnectors in Baja California have small non-significant effects on the network. And there is the presence of congestion costs.

Session 15:30 – 17:00
Energy transition

Room: HSZ/0401, hybrid
Chair: Dimitrios Glynos

Effects of fuel switching on electricity consumption and greenhouse gas emissions after the Russia–Ukraine war

Yeong Jae Kim, *KDI School of Public Policy and Management South Korea*

Defining green hydrogen: Does simultaneity benefit big players?

Nieves Casas, *RWTH Aachen University*

Reviewing energy transition studies in the light of recent European gas market developments

Daniel Brunsch, *Universität Duisburg-Essen*

Demand and generation in distribution grids: Future challenges and opportunities

Abhilash Bandam, *Forschungszentrum Jülich*

Effects of fuel switching on electricity consumption and greenhouse gas emissions after the Russia–Ukraine war

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Keywords: energy transition, fuel switching, greenhouse gas emissions, Russia's invasion of Ukraine

Motivation

Russia's invasion of Ukraine has made oil and gas prices soar. The War has impacted the global supply chain, fueling dramatic cost increases and accelerating inflation. It has impacted the speed and direction of the energy transition. Europe is currently facing an energy crisis as Russia cuts its supply of natural gas to Europe. Europe has depended on cheap Russian gas to run factories, generate electricity, and heat homes, but this exogenous shock has pushed European governments into a desperate situation as they reduce the consumption of electricity and return to coal- powered plants. However, the invasion is not only a crisis for the European Union (EU)'s Fit for 55 package but also for the energy transition. We examine the substitution of electricity generation fuels after the Russia-Ukraine War, affecting electricity consumption and greenhouse gas (GHG) emissions in Italy and Germany. We test whether the increased use of coal instead of natural gas resulting from the cut in gas supplies has led to a net increase in GHG emissions in two countries. The net effects vary spatially across two countries. Furthermore, we forecast future electricity consumption and GHG emissions with the war and without the war to develop solid policy insights and disseminate the research results to the general public and policy makers. Although there is enormous speculation on how the war affects the energy transition, there is a dearth of quantitative research on the changes in electricity generation and GHG emissions. By analyzing these relationships in a single econometric framework, we provide useful information to policy makers as they need to adjust their energy mix after the war.

Methods

We collect data on monthly electricity generation (i.e., % of nuclear, coal, natural gas, hydro, and renewables) from the ENTSO-E Transparency Platform from 2017 and 2022. We obtain the fuel emission factors of the energy sources for electricity generation (Scarlat et al., 2022). Our approach consists of three steps. First, we employ a time series model (i.e., ARIMA model) to construct the best fitted model for each country. Second, we forecast and predict future electricity generation in the aftermath of the war and compare it to electricity generation if there had been no war. Third, we convert the predicted electricity generation to carbon emissions based on fuel emission factors. We thereby predict and compare future electricity generation with and without the war by employing the ARIMA model that covers Italy and Germany from 2017 to 2022.

Results

Our preliminary findings are as followings. First, as Germany's coal-fired power plants has been restarted operations that replaced gas-fired electricity power plants after the war, Germany is faced with the future burden of energy transition. Second, as Italy is still heavily relying on gas-fired power plants, the effect of war on electricity generation was not as high as Germany's case. Third, Germany's electricity CO_2 emissions have increased more since the war than they would have without it. The opposite was true for Italy. Our findings can provide valuable information for further empirical analysis of the consequences of the Ukraine situation. On one hand, the current uncertainty regarding gas supply can lead some EU countries (e.g., Germany) to accelerate the energy transition to renewables. On the other hand, there are good reasons to believe that the coal phase-out will be delayed for a few years, which will hinder the energy transition. Furthermore, the role of natural gas as a bridge fuel to energy transition is questionable. Some of those positive and negative consequences will come into play in the foreseeable future. Our analysis will be a valuable contribution to quantifying the substitution of electricity generation fuels due to the shortage of natural gas after the Russia-Ukraine War, affecting electricity consumption and GHG emissions across the EU countries.

Defining green hydrogen: Does simultaneity benefit big players?

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Keywords: green hydrogen, electricity economics, energy transition, renewable energy, simultaneity

Motivation

Hydrogen is one key enabler of the transition toward net-zero economies, as a storage option for variable renewables and as an option to decarbonize hard-to-abate end-use sectors. However, the integration of hydrogen in the established energy system poses significant challenges in terms of policy measures, amongst other aspects. An example of the current political debate in the European Union around hydrogen is whether hourly simultaneity should be a precondition for the resulting hydrogen to be labeled as green. This requirement is defined as matching the green hydrogen with the renewable electricity it is produced from in an hourly resolution. In the existing literature on enforcing simultaneity, two main arguments and the trade-off between them are being discussed: the production costs and the CO2 emission intensity of hydrogen. However, very little research has been done so far on the role of owning a portfolio of assets when enforcing simultaneity. Provided there is a simultaneity requirement for green hydrogen production, owning an increasing number of technologically and regionally diverse renewable electricity producing units may lead to declining levelized costs of hydrogen (LCOH). This is because a portfolio reduces the volatility of variable renewable energy production through geographic and technological smoothing, which makes it easier to fulfill the simultaneity requirement. For instance, when owning units in different weather areas, a portfolio is more likely to be able to produce electricity despite possibly unfavorable weather conditions in some areas.

Methods

This contribution quantifies such potential portfolio effects arising from the enforcement or lack of a simultaneity requirement by comparing the LCOH of investors owning an individual production unit or a portfolio. To do so, we further develop and apply a linear cost-optimization model, which has previously been used to assess the effects of different policies on costs and emission intensity of green hydrogen. The model finds the optimal investment and dispatch for the different production units, including renewable generators, hydrogen electrolyzers, and hydrogen storage. The main constraints are on whether hourly simultaneity is enforced and on an assumed baseload demand for hydrogen, which needs to be fulfilled. This contribution further develops the model to account for investment and dispatch decisions at different locations. For each parameter combination (whether or not simultaneity is enforced and which technologies are used to produce the renewable electricity), the optimization model will be run three times. One for each individual unit (located in the North or South of Germany) and another one for both units running together as a portfolio. The investigation starts with two production units and is then envisioned to be expanded to a larger number of units. An additional sensitivity analysis will be carried out for different weather years.

Results

In the first scenarios, where simultaneity is not enforced, the portfolio is expected to reach an LCOH comparable to the one of the individual units. However, the moment that simultaneity is required, the LCOH of the portfolio should become significantly lower than that of the individual units. This is because a portfolio has the property of reducing the volatility of variable renewable energy production through geographic and technological smoothing, as described in the Motivation section. The magnitude of this effect is expected to depend on the number of units making up the portfolio and on the regional and technological diversity of the variable renewable generators. If the model results indeed provide evidence for the existence and relevance of this portfolio effect, it implies that bigger players would have a competitive advantage over small players from the enforcement of a simultaneity requirement. This would be against the goal of energy policy to create a level-playing field between actors of different sizes to spur competition and innovation. Not least, this would mean high entry barriers, a key obstacle to well-functioning markets. This would be an argument against enforcing a simultaneity criterion for green hydrogen on the basis of individual assets.

Reviewing energy transition studies in the light of recent European gas market developments

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Keywords: energy crisis, natural gas shortage, energy transition, meta analysis, hydrogen potential

Motivation

Since mid-2021 and especially after the Russian invasion of Ukraine, prices for natural gas on European markets have increased significantly . This is primarily due to reduced natural gas supplies from Russia to Europe, and correspondingly Europe has turned more towards other natural gas suppliers, including notably cargoes of liquified natural gas (LNG). Even if prices have declined again over the last months, they are still more than two times higher than before the crisis - and are expected to remain so as new supplies come at higher costs. Analogously, but not to the same extent, this also applies to oil and hard coal. To ensure security of energy supply, especially in winter, electricity generation has made increased use of coal, whereas industry has partly substituted oil (products) for gas. At the same time, for the political objective in Europe is to achieve full decarbonization until 2050. With the amendment to the Climate Protection Act, which came into force on August 31, 2021, the then German government even set the target of greenhouse gas neutrality for the year 2045. This is accompanied with increased emission reduction targets for the intermediate years (65 % reduction of greenhouse gases by 2030 and at least 88 % by 2040, both compared to 1990), which also affect the targets for the individual sectors, such as energy, industry, transport, buildings, and agriculture. Several studies have described transformation pathways which allow to achieve these goals. This contribution is intended to and to examine the most relevant studies in the context of the new developments on the international gas markets. Are the paths - especially in the medium term - described in the studies still valid given the new circumstances? The most recent energy transition studies for Germany that were published since 2021 are selected. That is, all studies are aligned on the goal of climate neutrality until 2045.

Methods

30 scenarios from six different studies that were published in 2021 and 2022 are evaluated. The scenarios are compared with respect to their results with a focus on natural gas supply in the short to medium term. Main outputs such as the projected primary energy consumption of natural gas.

Another focus is on hydrogen, which is expected to replace natural gas in several key sectors. Here, we compare the hydrogen demand of the different sectors, the share of imports in overall supply and the installed capacity of electrolyzers and their respective full load hours. The goal is to assess whether there is a risk of natural gas shortage caused by reduced and suspended imports from Russia and whether increasing LNG imports or substitution with (green) hydrogen - which might become competitive earlier than expected due to the higher natural gas prices - can fill the supply gap. The potential supply gap of natural gas until 2030 is calculated based on the natural gas consumption in the 30 scenarios. Historical data on natural gas imports, exports, domestic production, and storage balance up to 2022 are used. In a first, conservative setting the potential gas supply gap is calculated using the following assumptions: gas supplies from Russia are completely suspended, gas imports from other countries by pipeline, gas exports and domestic production are extrapolated from the average value for the years 2021-2022. In addition, the potential capacities from LNG are considered, including stationary LNG terminals from 2026 onwards and LNG terminals via FSRU's, which are partly already available since the end of 2022. After determining the supply situation for all scenarios, these are further analyzed to identify the assumptions which prevent or reduce a supply gap and those that lead to a rather high supply gap. On the other hand, the recent developments in gas markets are scrutinized to identify developments that may ease or exacerbate the supply situation.

Results

The investigated scenarios exhibit a wide range of gas consumption levels both in 2025 and in 2030, cf. Figure 1. Based on the aforementioned assumptions a supply gap occurs in all examined scenarios during at least one of the next years (cf. Figure 2). Three options are discussed to overcome this supply gap in the short to medium term. The first option is to reduce demand by saving gas as already practiced in 2022. In view of an ongoing or even further reduction in gas demand, we want scrutinize the available evidence notably regarding production shifts and substitution of natural gas by other energy carriers. The second option is to further increase the import capacities. Countries like Norway may continue to deliver more pipeline gas or LNG import capacities may be extended beyond the official plans both inside Germany and in neighboring countries. Also, the claims that already the planned LNG import capacities are rather excessive will be examined to identify risks and potentials in that area. As a third option in the medium term, (green) hydrogen could partially replace natural gas. The actual developments are scrutinized here to see whether the ramp up may come earlier than previously scheduled by the German government and what may be delivered by the IPCEI projects in this field and by further activities. As seen of today, the contribution of green or even blue hydrogen is expected yet to be very limited for 2025, where the potential supply gap is largest.

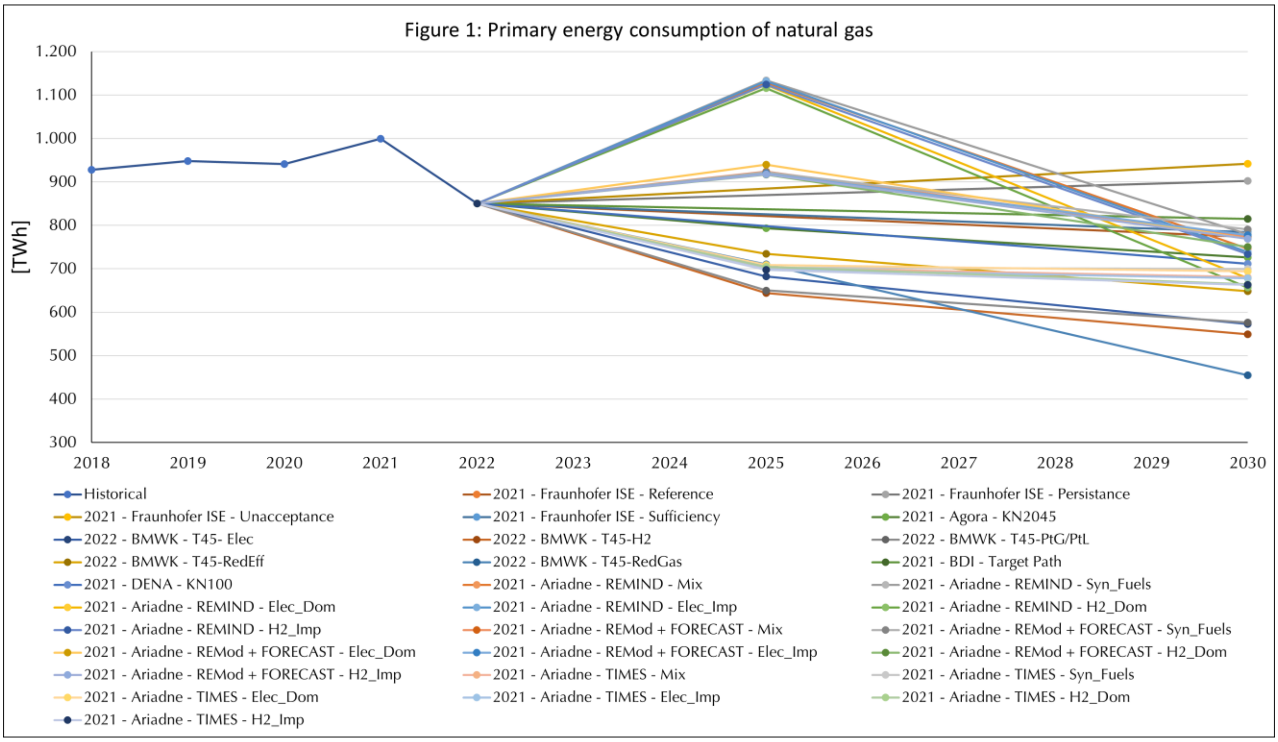

Figure 1

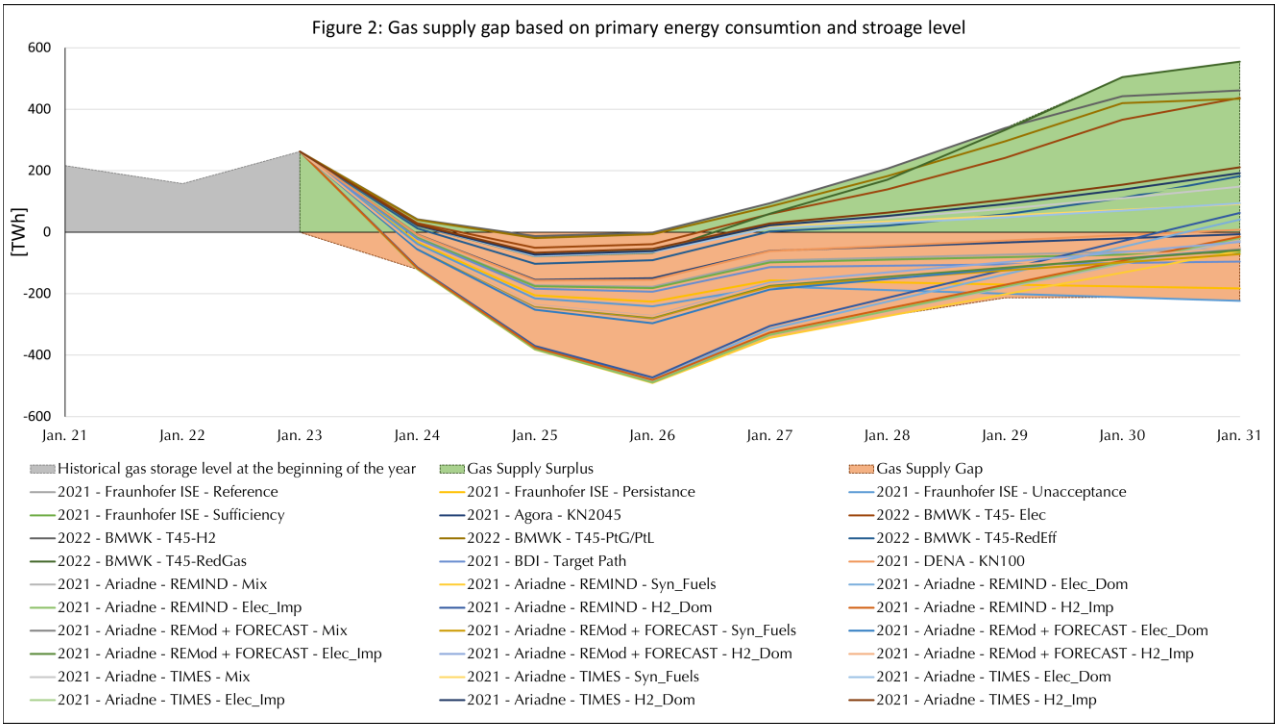

Figure 2

Demand and generation in distribution grids: Future challenges and opportunities

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Keywords: distributed demand and generation, synthetic networks, low-voltage networks, distribution grids, distribution networks

Motivation

To reduce carbon emissions, the electrical sector is increasingly adopting renewable distributed generation technologies. Rooftop solar PV is a major technology that provides renewable decentralized electricity generation. Furthermore, battery electric vehicles are being employed to minimize carbon dioxide emissions in the transportation sector. In addition, the market expansion of heat pumps is supporting efficient and clean heating in buildings. These demand and generation technologies are essential to achieve Greenhouse Gas neutrality targets. However, these technologies have been integrated into the distribution level of electrical power systems that were designed for different demand and generation structures. Consequently, it is necessary to explore the consequences of integrating these technologies into distribution networks. To perform a comprehensive analysis, we need the distribution network topologies. Because of security concerns, distribution system operators are reluctant to publish these topologies. Additionally, analyzing sample networks does not yield a comprehensive understanding. Therefore, this study aims to identify the effects of changing demand and generation in distribution networks by developing geo-referenced synthetic network topologies.

Methods

As previously stated, distributed demand and generation units are integrated into distribution networks, especially in low-voltage networks. In this study, the deployment of future demand and generation in Germany's low-voltage networks is analyzed. Germany is chosen as a case study because of its vast distribution grid designs. Network designs are required to address the impacts on distribution system components such as transformers and cables, and network vulnerabilities for the future. Initially, synthetic network topologies are created using open data for the purpose of analyzing the impact of distributed technologies on low-voltage networks. During the developmental phase, buildings extracted from OpenStreetMap are classified into distinct categories such as residential and non-residential, as the former constitutes the primary nodes of connection within the low-voltage network. The OpenStreetMap data are integrated with multiple other datasets in the pre-processing phase. A machine learning algorithm is utilized to classify building types on the pre-processed dataset, addressing issues such as missing values, class imbalance, and classification. The model identifies 19,747,802 buildings among the 29,497,992 buildings in the dataset. Following validation against the actual number of residential buildings, the results indicate a percent error of 3.4%. Next, a systematic approach is employed to generate geo-referenced synthetic low-voltage networks utilizing various algorithms. This involves collecting relevant data, such as classified buildings, street networks from OpenStreetMap, and the total number of existing networks in Germany, followed by clustering the buildings, mapping them to the street networks, connecting them to the street edges, and placing transformers inside the network. With these methods, 500,000 low-voltage networks are generated. Finally, these networks are statistically, operationally, and geo-graphically validated with real existing data.

Results

In an effort to minimize CO2 emissions, the incorporation of solar rooftop PV, battery electric vehicles, and heat pumps was studied to determine their impact on low-voltage networks. The studied scenario is based on the results of an energy system scenario that reduces CO2 emissions by 95% by 2050. It entails the incorporation of 53% solar PV, 80% BEVs, and 83% heat pumps into the distribution networks by 2050. Subsequently, power flow calculations are carried out to assess the thermal loadings on the grid components and voltage violations on the network nodes resulting from these integrations into the low-voltage networks. By performing power flow simulations over weekdays and weekends for four different seasons, an analysis of the data reveals that 25% of the low-voltage transformers are crucial due to transformer overloading. Furthermore, 75% of the low-voltage network transformers experience reverse power flows, with 25% of them being considered critical. This means that most of the generation is underutilized at low-voltage networks, leading power to flow upward. When all 500,000 networks are considered, an average of 11% of the lines are overloaded and require reinforcement. Lastly, on average, 34% of the nodes in the networks need to be addressed for voltage violations. Based on these findings, it can be inferred that addressing the above-mentioned violations by incorporating voltage-regulated transformers, new lines, and smart demand side management devices would enable the low-voltage networks to accommodate a substantial increase in distributed demand and generation in the future.

Session 15:30 – 17:00
Decentralised energy supply

Room: HSZ/0301
Chair: Lucas de la Fuente

Sustainable municipality modelling: Clustering-based bi-level optimization of a decentralized municipality energy and resource treatment infrastructure portfolio
Matthias Maldet, *Technische Universität Wien*

Comparison of CO2 and cost-optimised energy system for a residential building in Germany
André Eggli, *Hochschule Luzern*

Modelling district heating systems transition towards climate neutrality, case study of Poland
Maciej Raczyński, *AGH University of Science and Technology*

Investigation of seasonal congestion situations in modern rural integrated distribution grids
Tom Steffen, *Technische Universität Hamburg*

Sustainable municipality modelling: Clustering-based bi-level optimization of a decentralized municipality energy and resource treatment infrastructure portfolio

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Keywords: bi-level optimization, clustering methods, municipality portfolio analyses, sector-coupling modelling, community modelling

Motivation

Reaching European climate targets requires interaction between centralized and decentralized generation and conversion technologies. Community operation in the form of renewable energy communities or sustainable communities is often mentioned as a possibility to promote consumer engagement in decentralization. However, these communities often miss a driving force in community formation and technology investments. Municipalities could emerge as an operator for decentralized local energy and resource markets by providing technologies and a local marketplace. The efficient operation of local markets in municipalities should consider resources like waste and sewage. Energy recovery from waste treatment and marketing of such in a municipality could play a fundamental role in decentralized local municipality markets. Furthermore, sewage treatment requires high electricity input energy that should be considered in analyses. Investment decisions in treatment plants and consumer technologies such as PV and heatpumps are investigated. Analyses are performed by developing an optimization model that considers local market operations and investment decisions. However, this leads to high computation time in solving the problem. Therefore, a clustering-based bi-level optimization model is developed to assess the investment and operation of a sustainable municipality.

Methods

A municipality in Lower Austria is set up as a sustainable municipality. Investigations on the local market operation and portfolio optimization are performed in the municipality. Investment decisions are performed for PV, heat pumps and batteries. Additionally, investment decisions in waste and sewage treatment plants are carried out. District heat investment is further analyzed to use recovered heat from waste incineration in the municipality. Residents in the municipality are aggregated into four representative consumers. Additionally, public buildings and office buildings of local government are considered as own aggregated consumers. Electricity trading between consumers is enabled, and consumers can procure heat from the municipality. Investment decisions and operational analyses are decoupled in a bi-level optimization framework to solve the problem. A portfolio optimization in the municipality is performed in the first step of the optimisation. Annual input data in hourly resolution is clustered into two representative weeks by applying a K-means algorithm. The clustering is done for each month with 30 representative hours for monthly variation. Additional data processing is required for the optimization, whereas K-means algorithms consider mean values as cluster centers. However, for determining treatment capacities, maximum values of resource occurrence must be considered, and a weighting of the cluster centers by maximum values is required. Evaluated capacities in the first step are given as input parameters in the second step. The second step considers a detailed operational analysis of the municipality for a whole year in hourly resolution. The bi-level approach aims to evaluate investment decisions and detailed operational analyses while still keeping the computational time at an acceptable level.

Results

Results of the optimization model showed that a sustainable municipality can provide a marketplace for residents. Trading is carried out between consumers to reduce electricity grid procurement. Moreover, recovered energy from waste treatment can be marketed to residents. Consumers carry out district heat investment to purchase the required heat. Investment decisions in waste and sewage treatment plants are based on resource transportation distance and energy availability. A comparison with four-hour mean value optimization is performed to assess the impact. The proposed bi-level optimization framework was efficient. PV investment was carried out to the same capacity in both approaches. District heat systems were installed at the same positions in both methods but at slightly different allocations. The investment of battery storages was undermined in the bi-level practice compared to the four-hour mean-value approach by 36%. Heat pump investment was carried out at 1,6% more but with similar ratios in different positions. Waste and sewage treatment plants were installed at the same capacities at the exact locations in both optimization approaches. A significant advantage was seen in the reduction of the computation time. Computation time decreased from over ten hours in the four-hour mean value approach to 50 minutes in the bi-level method, thus resulting in a computational time reduction of 92%. However, the municipality operation was less cost-efficient in the decoupled modelling, leading to cost increase of 11,5%. Overall, the developed bi-level optimization framework was efficient by means of technology allocation and computational time reduction. A slight increase in costs should be accepted due to all the other advantages of the approach. Since only one option for waste treatment in the portfolio is analysed, the bi-level approach can have an even higher impact in more complicated portfolio optimization scenarios.

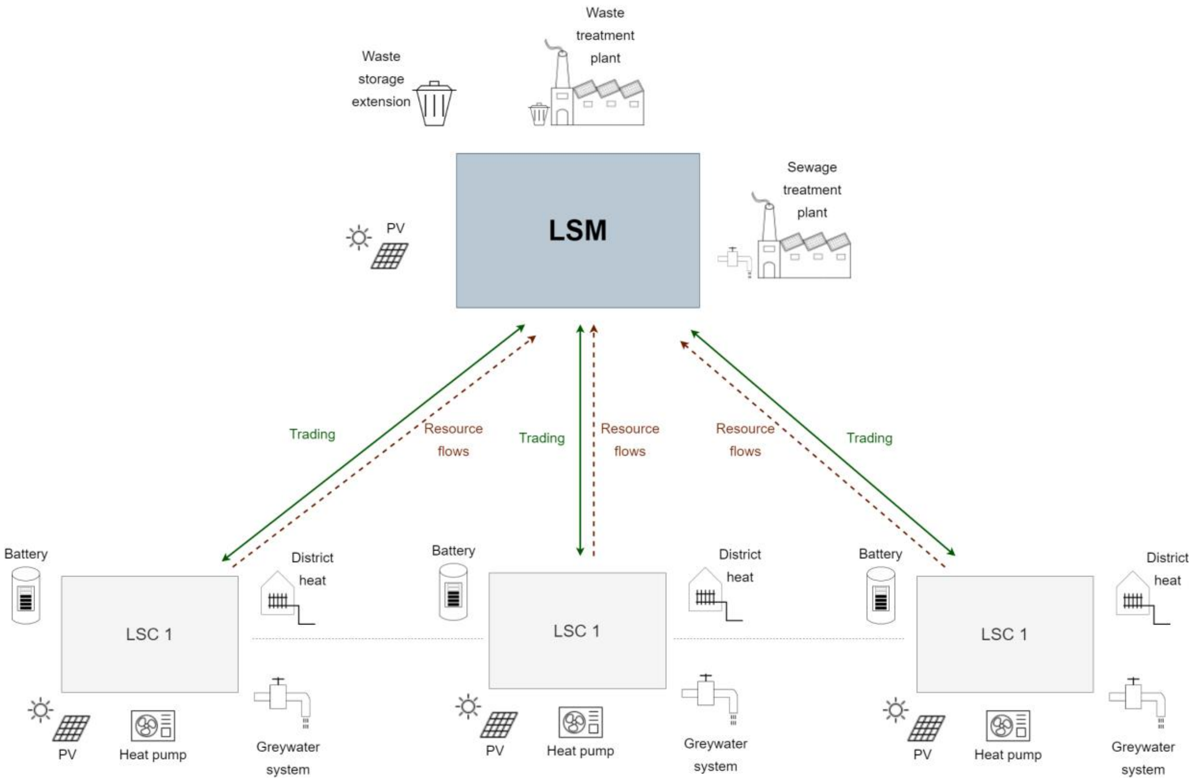

Figure 1

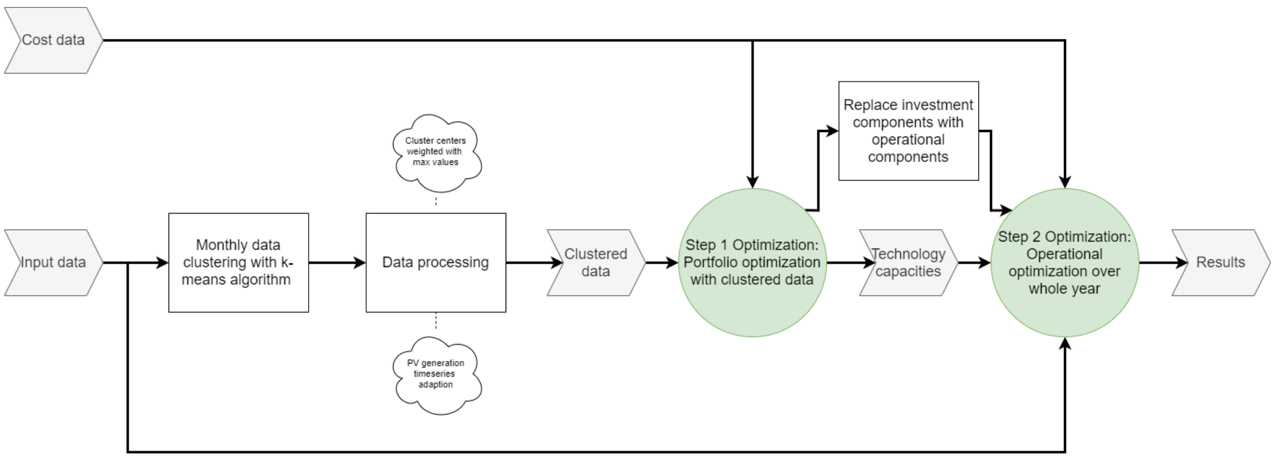

Figure 2

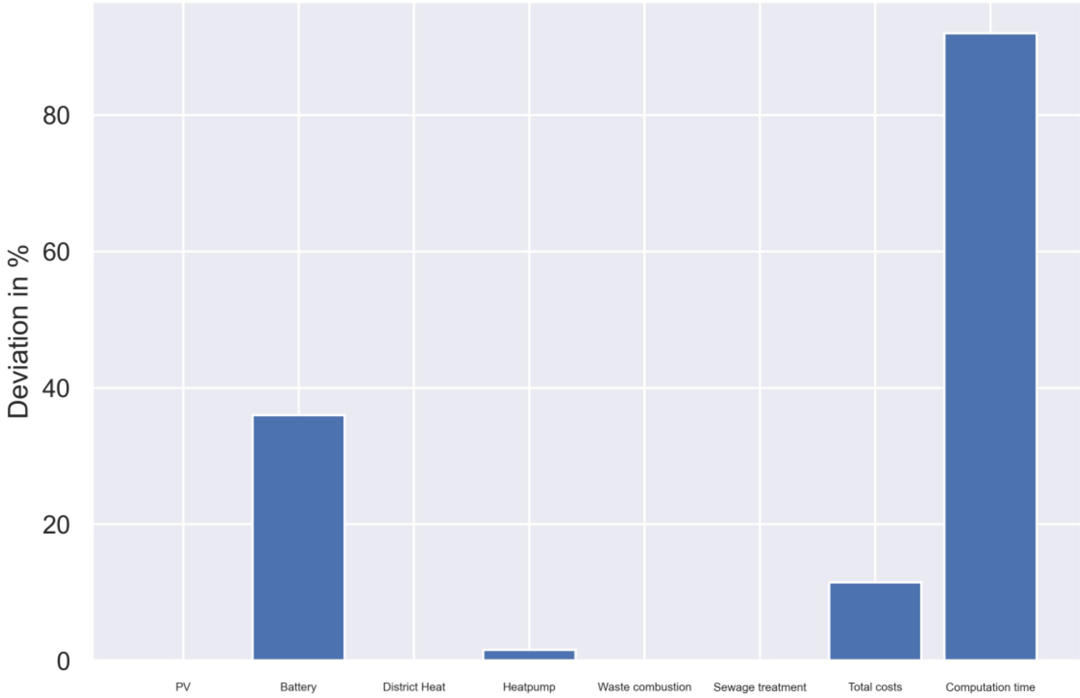
80
60
40
20
0
Deviation in %
PV
Battery
District Heat
Heatpump
Waste combustion
Sewage treatment
Total costs
Computation time

Figure 3

Comparison of CO2 and cost-optimised energy system for a residential building in Germany

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Keywords: CO2 minimisation, sector coupling, heating systems, fuel cell, residential building

Motivation

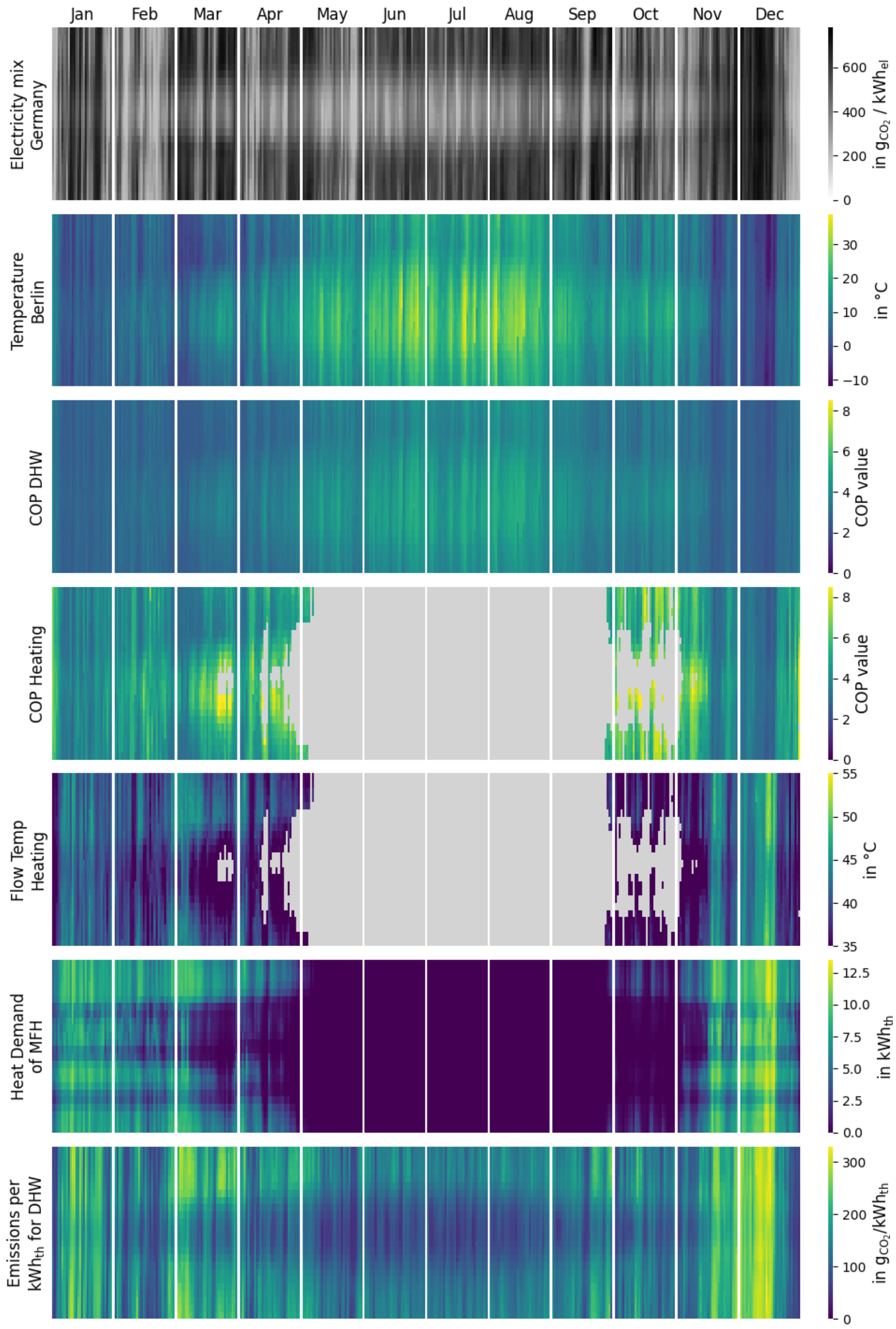
The issue of CO_2 emissions in residential buildings is a critical problem that requires urgent attention. This paper sheds light on the potential of fuel cell micro-combined heat and power (FC-mCHP) systems to substantially reduce CO_2 emissions in heating systems in Germany. In addition, the paper conducts simulations for various heating configurations to determine the best control strategies for reducing overall CO_2 emissions. Therefore, this paper aims at quantifying and minimising annual CO_2 emissions for heating one representative type of residential building in Germany, considering different types of heating. Six configurations of heating systems, including two types of fuel cells, a heat pump, an auxiliary gas boiler, and hybrid systems (heat pump + fuel cell and gas boiler + fuel cell), are dimensioned and simulated for a single-family house. Their control strategies are optimised towards using or generating energy when CO_2 reduction potential is highest. This shift to hours with a lower CO_2-intensive electricity mix is mainly enabled by using the thermal inertia of the buildings or the hot water storage for heat load shifting. In addition, the operation cost of the different systems is calculated. The study provides a comprehensive understanding of the subject and can offer actionable recommendations for reducing CO_2 emissions in residential heating systems. Furthermore, it underscores the importance of taking proactive measures to reduce CO_2 emissions in all sectors, including residential heating systems, to combat climate change and achieve a sustainable future.

Methods

The methodology employed in this paper consists of three main steps. Step 1 involves the collection and pre-processing of relevant data. The reference buildings' hourly heat and electricity consumption profiles, weather and hourly electricity emissions data are obtained, as well as the energy price projections and feed-in tariffs data. All data is pre-processed to ensure its accuracy and suitability for analysis. In Step 2, four predefined system configurations are optimised towards minimal CO_2 emissions. The configurations are an auxiliary gas boiler, a heat pump, a combination fuel cell + heat pump, and a combination fuel cell + auxiliary gas boiler. Six scenarios are analysed by considering two fuel cell technologies. The optimisation is performed using an energy system model that accounts for the energy consumption and production of the system and the electricity emissions associated with the production of the consumed electricity. The linear optimisation model aims to minimise the CO_2 emissions of each system configuration while ensuring that the building's energy demands are met. In Step 3, the results obtained from the optimisation are evaluated based on metrics such as annual CO_2 emissions and annual gas + electricity costs. Finally, the best system configuration with minimal CO_2 emissions and the lowest costs is determined, taking into account the earnings from the sold electricity of the fuel cell.

Results

The findings suggest that using FC-mCHP systems can help to reduce CO_2 emissions in residential heating systems, making it an attractive option for homeowners and policymakers alike. Furthermore, the study quantifies the operational cost of various heating systems, providing valuable insights into the economic viability of different solutions. In Figure 1, various parameters are plotted in a heatmap over the reference year 2022 to identify their influence on each other. Results for the multi-family house scenarios can be found in Figure 2 and Figure 3. Based on the study findings, it is recommended that hybrid scenarios incorporating fuel cell and heat pump technologies should be considered for reducing CO_2 emissions in residential heating systems in Germany. The study also suggests hybrid systems demonstrated better resilience to price fluctuations than other system configurations. Furthermore, to encourage sustainable energy practices, incentives should be provided to promote CO_2-optimized production patterns. These incentives can help to promote sector coupling of the heat and electricity sectors, thereby reducing CO_2 emissions in the heat sector and encouraging homeowners to adopt more sustainable energy practices. Finally, regarding the most effective solution for minimising CO_2 emissions, it is suggested that the hybrid system combining fuel cell and heat pump technologies would be the most suitable option. The study recommends further research to evaluate the cost-effectiveness of the various system configurations, including CAPEX and maintenance costs. In addition, policymakers should consider implementing policies that encourage homeowners to adopt sustainable heating systems, such as those evaluated in this study, to help mitigate climate change's impact.


Jan
Feb
Mar
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May
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Oct
Nov
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Electricity mix Germany
in g_{CO_2} / kWh_{el}
Temperature Berlin
in °C
COP DHW
COP value
COP Heating
COP value
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Heat Demand of MFH
in kWh_{th}
Emissions per kWh_{th} for DHW
in g_{CO_2}/kWh_{th}

Figure 1

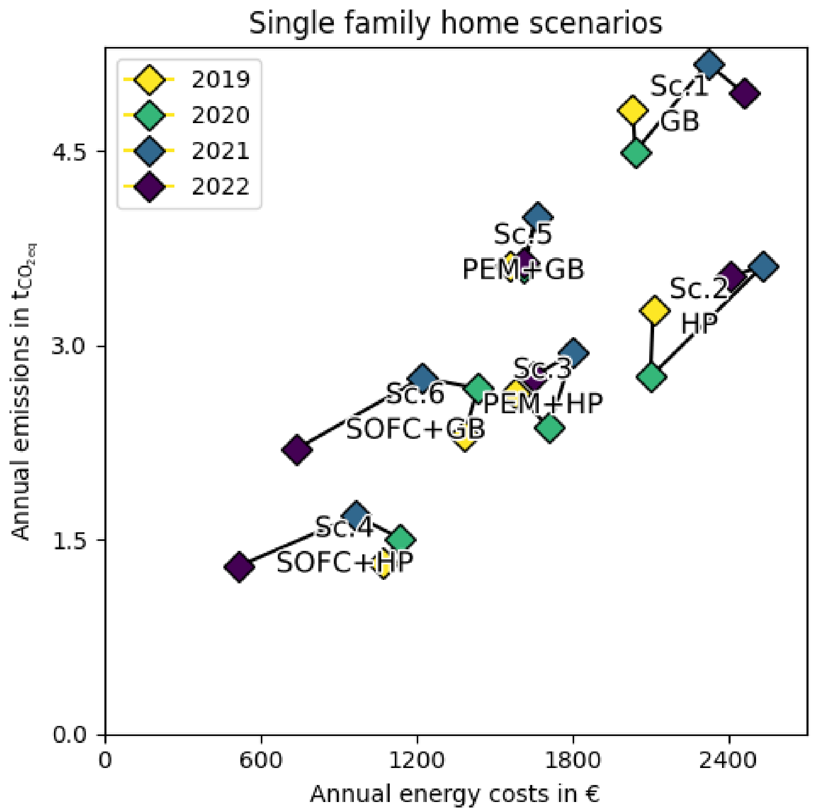

Figure 2

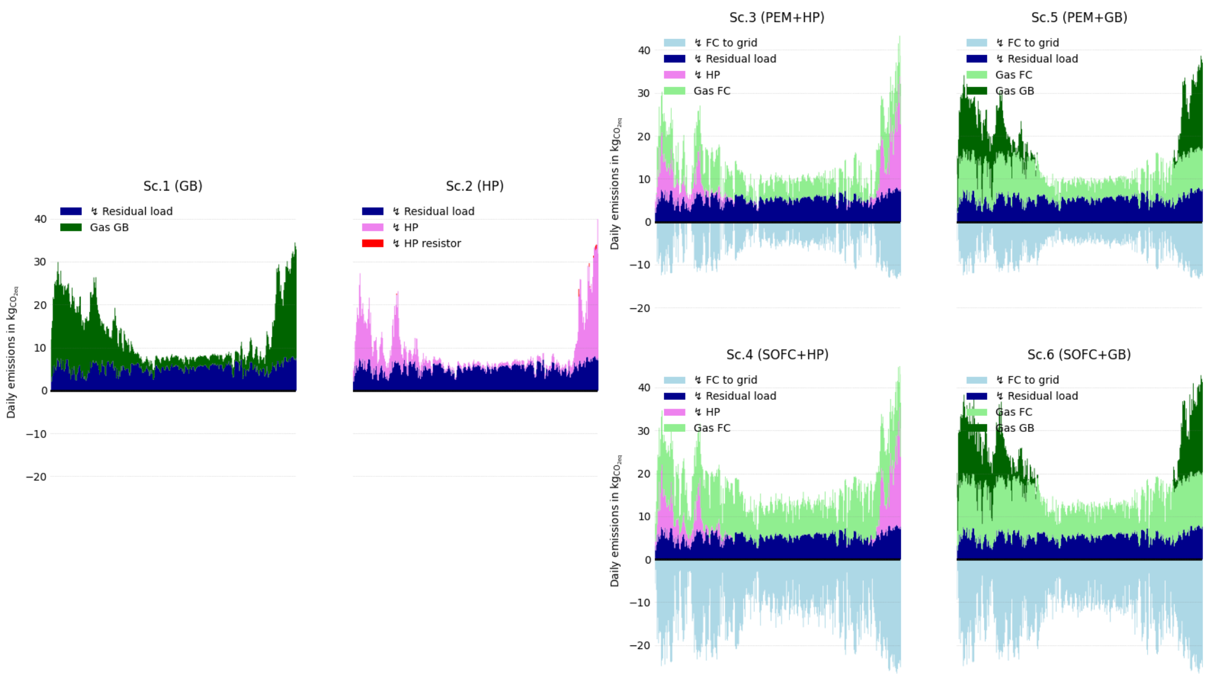

Figure 3

Modelling district heating systems transition towards climate neutrality, case study of Poland

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Keywords: energy modelling, district heating, capacity expansion, decarbonization, geospatial data

Motivation

Currently, most of the district heat is still produced using fossil fuels. District heating systems are, therefore, an important part of the energy transition in many countries. Moreover, district heat could also play a significant role in the decarbonisation of other sectors, e.g. residential, by replacing individual boilers as a source of heat. District heating systems, unlike the electricity network, are separate entities. They vary significantly in heat demand, power and types of generation units as well as local conditions, e.g. fuel availability. Widely used in policy development, long-term optimisation models often treat district heating systems as a single system and, therefore, cannot represent those individual characteristics properly. On the other hand, detailed models of individual systems, used by their operators to plan future development, make many exogenous assumptions. In particular, assumptions about the price of electricity, which is both the main driver in the development of Power2Heat technologies, and the result of the operation of the district heating system, if it contains a CHP plant. There is therefore a case for creating a modelling framework that reflects the characteristics of individual district heating systems, while treating them as a part of the entire energy system. This will allow for a better representation of the dynamics between district heating systems and the rest of the energy system, as well as a better understanding of the role of district heating systems in the energy transition.

Methods

An optimisation, capacity expansion model, called TIMES-Q, was created using the TIMES model generator. In the model, each district heating system is represented as a separate region. The characteristics of the system include: 1) a set of existing heating and/or CHP plants represented as separate processes; 2) a heat demand curve; 3) fuel prices and availability of energy sources; 4) a set of new technologies in which the model can invest in the future, including heat storage. Because the district heating systems are represented as separate regions, many aforementioned characteristics are based on the geographical location of the system. For example, availability of geothermal technology, fuel delivery costs, solar irradiation profile. The national energy system is modelled as a separate "global" region, with which all the district heating systems can trade commodities, such as electricity. This global region is at the same time a way of linking the TIMES-Q model with an external national energy system model (TIMES-PL). Both models work in a loop, exchanging information on installed generation capacities until the results converge.

Results

The main result of TIMES-Q model is a cost optimal set of new heat generation capacities and generation profile for each individual district heating system. This includes new storage facilities and their operation profile. Based on this, the heat generation price can be calculated for each system. Since the price of heat is the main factor determining the competitiveness of district heating systems with other heat sources, it can be used to assess the level of support that district heating systems will require on their way to decarbonization. The exchange of data with the national energy system model will allow it to better represent the development of district heating systems and more realistically assess their transformation.

Investigation of seasonal congestion situations in modern rural integrated distribution grids

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Keywords: distribution grid modeling, integrated energy system, congestion situation, seasonality, Modelica

Motivation

In the Paris climate agreement, the international community has committed to limit global warming. In order to achieve this, the German government is taking considerable effort in transforming the energy system from a fossil-fuel-based system into a sustainable system relying on renewable energy sources. In todays energy systems the share of intermittent and distributed renewable generation is therefore rising rapidly. At the same time minimizing the transformation cost is necessary, while securing supply safe and economic optimality in operation. To achieve this balancing act, stakeholders follow the NOXVA principle, meaning grid optimization before flexibility before reinforcement before expansion, leading to the integration of the different energy sectors, electricity, gas and heat and also mobility. The accompanying shift in demand for example induced through electric vehicles and heat pumps is bound to stress especially the electrical distribution grids making grid bottlenecks in form of congestions considerably more likely. In this paper the authors contribute their findings regarding the investigation of season-dependent congestion situations in modern and future rural medium and low voltage grids, while taking into consideration the interface technologies of those multi-modal energy systems. The distribution grid, consisting of a medium voltage grid with highly-detailed subdivided bottom-up modeled low voltage grids, is modeled based on the open-source TransiEnt-Library for dynamic modeling of multi-modal energy systems. The congestion situation in favourable and less favourable situations, for example moderate and low outdoor temperatures, is represented and evaluated. First results of the simulation show that severe congestions occur especially under severe ambient conditions with consequently high simultaneous energy demand.

Methods

The investigated rural distribution grid is modeled in Modelica using the open-source Transient-Library, and based on a medium voltage benchmark model taken from the SimBench scenario MV-rural-2-no-switches, with the adequate low voltage sub-grids LV-rural-1, consisting of a topology with 13 households, and LV-rural-2, consisting of a topology with 99 households. The detailed modeled households, in this case called prosumers, are dynamic models considering ramping-rate limitations and interactions between energy sectors and controllers. The prosumers consider distributed generation in form of weather-based photovoltaic generation, modern consumption in form of air-water electric heat pumps, electric vehicles with study-based driving profiles and inflexible loads. Additionally, consumer-side self-sufficiency optimization with battery electric household storages relying on inaccurate measurements from modeled smart meters is included (Paper NEIS 2022). The congestion investigated is based on two weather scenarios. In both scenarios the penetration of technologies, for example the share of prosumers having electric vehicles, is based on the distributed energy scenario from [MDPI Paper]. Both scenarios weather data series are provided by the DWD (Deutsche Wetterdienst) for the location Hamelin in Lower Saxony, Germany. In the first scenario, a 48-hours study of the grid in a favourable situation is based on the weather data from April 2020. The mean outdoor temperature in this scenario is thereby close to 20 °C, leading to inactive electric heat pumps. Additionally, the solar irradiation and wind speed are leading to high renewable generation in this scenario. The second scenario is a 48-hours study in a less favourable situation based on the weather data from december 2020. Hereby, the mean outdoor temperature is close to 0 °C resulting in highly active electric heat pumps with high concurrency. The renewable generation in this scenario is comparably low.

Results

When investigating the two scenarios in terms of the congestion situation, the important characteristics are the line and transformer loading, typically given by the current-carrying capacity, as well as voltage band limitations, e.g. 10% deviation of the nominal voltage. When focusing on the results from the first scenario, Fig. 1 to Fig. 3, one can see that the voltage in the specific grid only within the first hours is close to its limitations, which can be explained by an unrealistic simultaneity of consumers in the grid due to initialization of the storage components. In the remaining time of the simulation the voltages stay in an interval of about 5 % deviation from its nominal value. The situation is different when focusing on the line and transformer loadings, where even after initialization have subsided, a clear pattern is recurring in the evening hours of each day, leading to loading situations near or above its maximum in the low voltage grids. This is explainable due to the arrival time within the electric vehicles stochastic driving profiles is likely to be in this time period. At the same time, however, the line loading in the medium-voltage grids is not close to its limits, due to larger capacities. In the second scenario the situations differ, Fig. 4 to Fig. 6, since in the evening hours the heat demand and therefore the power consumption of electric heat pumps in the grid further aggravates the situation, leading to a highly simultaneous energy demand. This results in higher deviation within the voltage band as well as daily recurring congestion situations in line and transformer loading of the low voltage grids. In this scenario specific medium voltage lines are operated over their current-carrying capacity due to weather induced effects. Overall the comparison of these scenarios for this rural benchmark grid leads to the conclusion that especially the low voltage grids run the risk of being frequently exposed to unfavourable situations in future.

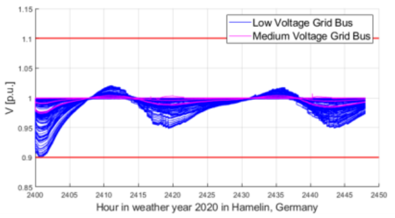

Fig. 1: Voltages in medium and low voltage grids in scenario 1

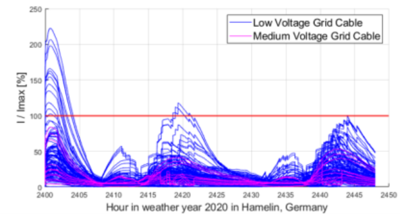

Fig. 2: Line loading of medium and low voltage cables in scenario 1

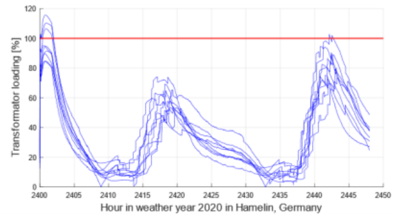

Fig. 3: Transformer loading between medium and low voltage grids in scenario 1

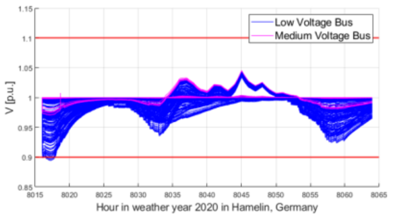

Fig. 4: Voltages in medium and low voltage grids in scenario 2

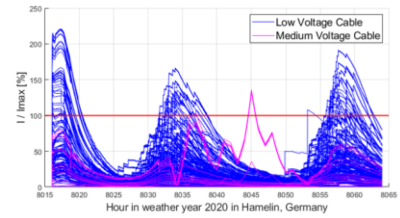

Fig. 5: Line loading of medium and low voltage cables in scenario 2

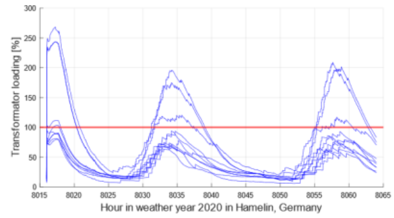

Fig. 6: Transformer loading between medium and low voltage grids in scenario 2

Figure 1

Session 15:30 – 17:00
Technology assessment

Room: HSZ/0304
Chair: Alexander Wimmers

Economics of nuclear power in decarbonized energy systems

Alexander Wimmers, *Technische Universität Berlin*

Efficient electricity distribution and sustainable energy management through Big Data analytics and machine learning

Andrej Somrak, *Troia d.o.o.*

Functional technology foresight: Case study for direct air capture and storage

Freia Harzendorf, *Forschungszentrum Jülich*

Effect of the energy crisis on short-term and long-term market design - An economic assessment

Maxime Amadio, *Compass Lexecon*

Economics of nuclear power in decarbonized energy systems

Alexander Wimmers[1]

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Keywords: nuclear power, decarbonized energy system, cost analysis, energy system model

Motivation

In addition to renewable energy strategies, several governments are increasing previously stated efforts for the construction of new nuclear power plants or re-considering this option to combat climate change and reduce fossil fuel dependencies Nuclear power can be advantageous, by possibly providing flexible operation or helping in decarbonization efforts through low-carbon electricity provision to various sectors. However, from an economic perspective, nuclear power is becoming increasingly expensive as capital costs sore for current new build projects in OECD countries, while renewable energy technologies, such as wind and solar, are becoming cheaper and options to manage flexible electricity production are becoming more sophisticated. We therefore ask whether nuclear power is a cost-efficient technology in a future decarbonized energy system.

Methods

To answer this question, we follow a two-step approach. First, we conduct a detailed analysis of projected and actual costs of nuclear power plant projects to determine the conceivable range of levelized cost of energy (LCOE), discuss nuclear industry projections and actual reported figures as well as provide a comparison to alternative technologies, namely renewable. This analysis includes various papers, studies and reports and provides a detailed insight on nuclear cost components, beginning with the major component, capital cost, over operational cost to indirect influences such as construction time and capacity factors. The analysis of results is limited to gigawatt-sized light-water-reactors in OECD countries. Second, using results obtained in the cost analysis, the efficient share of nuclear power in a decarbonized energy system is computed using a comprehensive techno-economic model. This model is based on the AnyMod Framework developed by Göke (2021). With previous research limiting flexibility options such as cross-border exchange, demand-side flexibility and focusing on short-term storage systems, this model, while focusing on Europe, considers all alternatives to nuclear power for electricity and flexibility.

Results

Results of the cost analysis show that a discrepancy lies, especially for nuclear capital costs, between projected costs or model assumptions and actually observed figures, see Figure 1. Additionally, OECD countries report, on average, higher costs than non-OECD countries, esp. China. Other cost components also vary, but not as prominent. From this analysis, we determine a broad range for nuclear LCOE, and therefore compute multiple scenarios with a capital cost range of 2,000 to 8,000 2018-USD/kW and favorable assumptions for other components and parameters. As shown in Figure 2, share of nuclear in electricity generation depends highly on the assumed capital cost. Most notably, this share does not exceed 50% even at the lowest cost level and quickly drops once higher costs are assumed. Cost ranges in which a measurable share of nuclear power is installed are in the low-range of projections and well below actually reported project costs. To conclude, we find that capital costs for nuclear must fall significantly to become economically viable compared to alternative technologies in a decarbonized energy system. Whether this can be achieved, is disputed in literature. However, non-electrical uses of nuclear power for, e.g., process heat and the application of non-light-water technologies might change this assessment . This techno-economic cost analysis neglects costs for nuclear waste management and decommissioning and does not assess non-economic disadvantages of nuclear power such as the risk of severe nuclear accidents, proliferation and radioactive contamination.

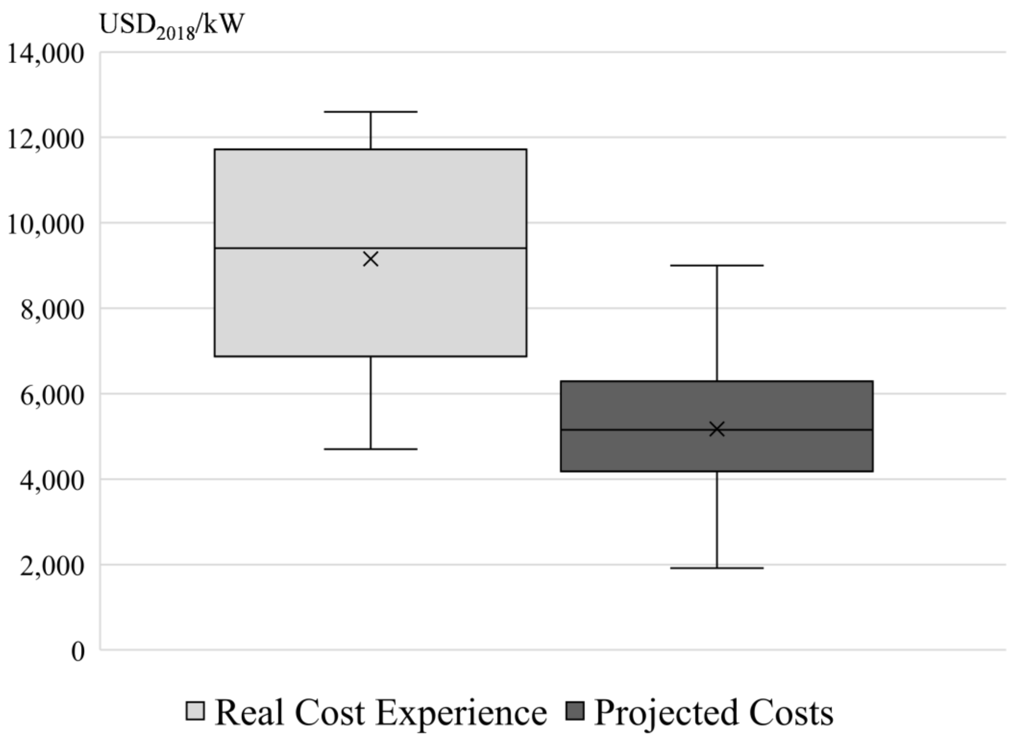

Figure 1

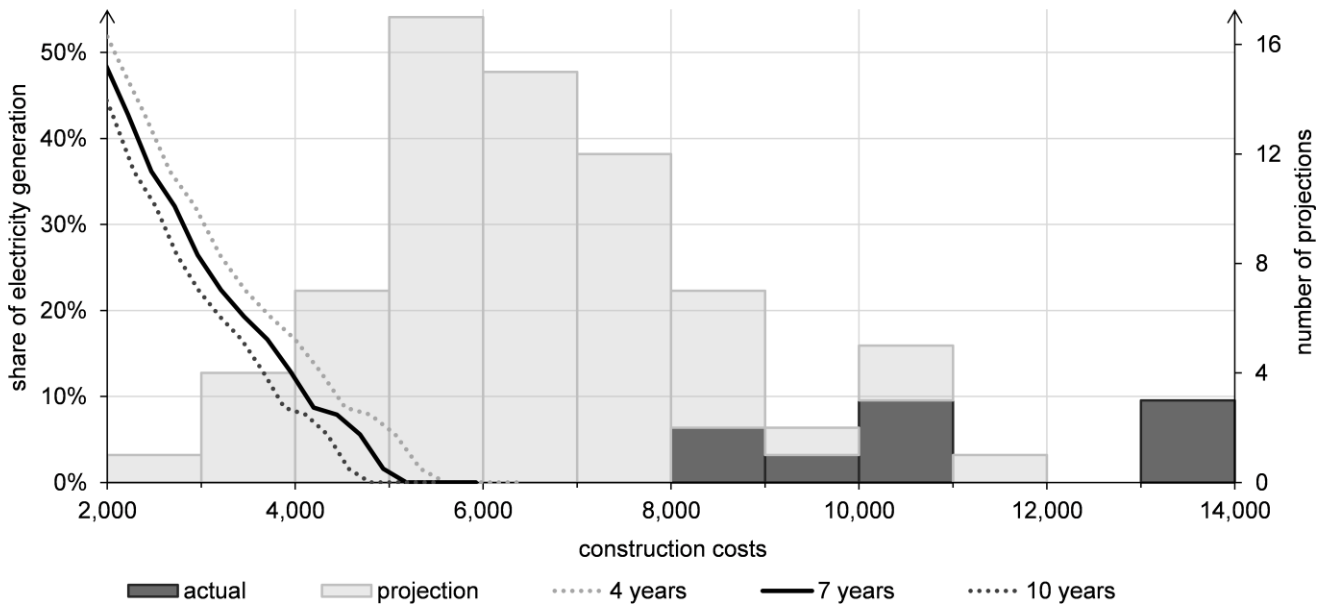
50%
40%
30%
20%
10%
0%
share of electricity generation
16
12
8
4
0
number of projections
2,000
4,000
6,000
8,000
10,000
12,000
14,000
construction costs
actual
projection
4 years
7 years
10 years

Figure 2

Efficient electricity distribution and sustainable energy management through Big Data analytics and machine learning

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Keywords: smart meters, big data, distribution grid, analytics, machine learning

Motivation

In today's world, where the demand for energy is constantly increasing, managing electricity distribution systems has become complex and challenging. Advanced metering systems have emerged as a solution to improve the efficiency and accuracy of managing these systems. These systems provide accurate and real-time information on electricity consumption, which helps utility companies to manage the supply of electricity to end-users better. However, the large amount of data generated by these systems poses a significant challenge in terms of maintenance, management, and data storage. Traditional client-server and relational database techniques are not capable of efficiently analyzing this large amount of data, which creates the need for a more general data management and analytics platform. The use of modern Big Data concepts and industry-proven scalable technologies can help overcome these challenges and provide better insights into electricity distribution systems, which is crucial for several reasons. Firstly, it can provide a holistic view of the electricity distribution system, which can help identify areas of improvement and optimize the overall system. Secondly, it can enable utility companies to make informed and data-driven decisions, which can improve the reliability and quality of electricity supply. Thirdly, it can help in achieving the goals of green transition and energy transformation by providing insights into the usage patterns of electricity and identifying areas where renewable energy sources can be integrated. The importance of a data management and analytics platform becomes even more critical in the context of the global push toward renewable energy and sustainable development. The transition to renewable energy sources requires a deeper understanding of the electricity distribution system, which can only be achieved through the efficient analysis of large amounts of data.

Methods

We present a data management and analytics platform architecture that utilizes modern Big Data concepts and scalable technologies to address the challenges posed by the large amount of data generated by advanced metering systems. Instead of relying on the traditional Meter Data

Management System (MDMS), a more general approach was adopted. The platform employs advanced algorithms and machine learning methods to analyze and correlate data from multiple sources. We also show the operational, organizational, and strategic benefits of converging these data sources, providing valuable insights for effective decision-making.

Results

The general approach to data management and analytics can enable informed, timely, and data-driven decisions that drive modern utility companies. The presented platform provides a solution to the complex and extensive work of managing the large amount of data generated by advanced metering systems, enabling more efficient and effective management of electricity distribution systems. Furthermore, the use of advanced algorithms and machine learning methods allows distribution companies to continue to provide high-quality and reliable electricity to end-users while also achieving the goals of green transition and energy transformation.

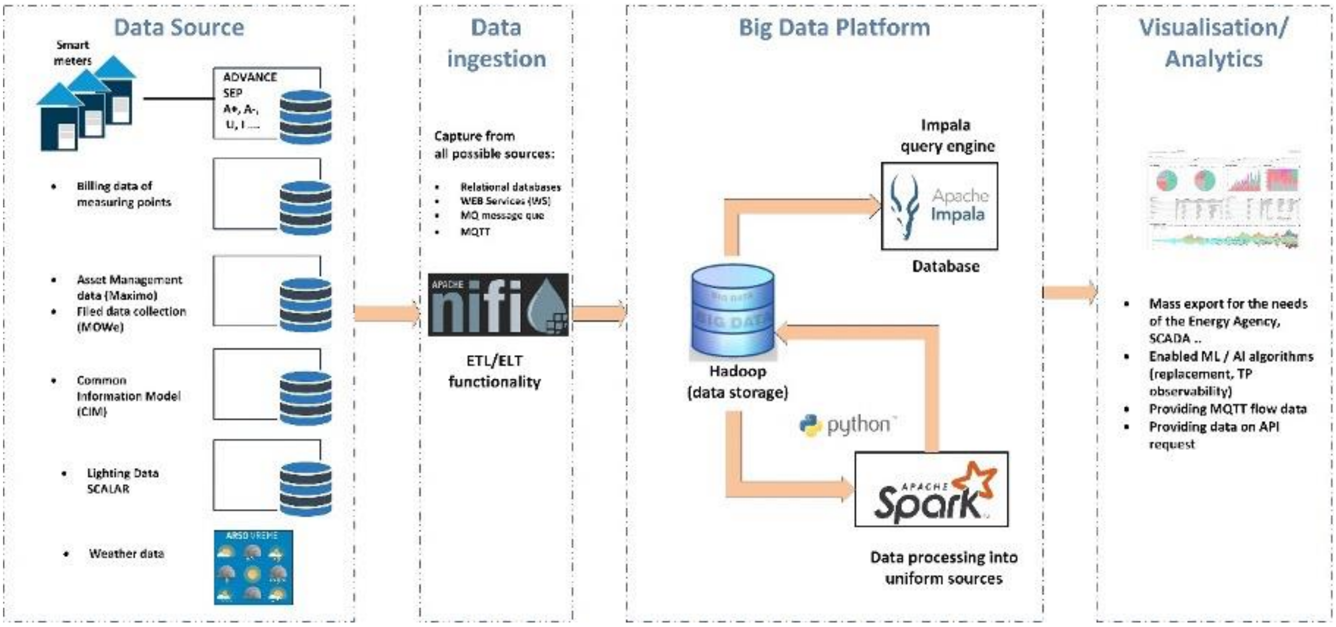

Figure 1

Functional technology foresight: Case study for direct air capture and storage

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Keywords: technology foresight, systems analysis, direct air capture and storage, emerging technology

Motivation

Direct Air Capture and Storage (DACS), the capturing of CO2 from the ambient air and its storage in geological formation, is an important negative emission technology with the potential to help mitigating global warming and climate change. In different scenarios of the latest IPCC report DACS is assumed to provide a significant amount of negative emissions to reach the COP21 goals. However, this is a young emerging technology in a very volatile developing field with several different technical possibilities and frequent publication of new technical approaches and materials. Its current major challenges are huge energy requirements and high cost for the capturing and sequestration. Available data contains a high level of uncertainty especially with regards to the technology's upscaling from current laboratory and pilot plant stage. Still this technology needs to be accurately modeled in systems analysis to derive the impact of its broad roll out on the system, suitable sites for its application etc. With these characteristics DACS can be seen as a representative for other immature technologies with a huge impact on the energy system. To conduct reasonable systems analysis, the following questions need to be answered in an unbiased way: What are characteristics of successful DACS plants? In which direction is future DACS plant development heading? Which aspects are important to include in systems analysis and in which way? This leads to the publication's overall goal: the provision of a systematic approach to allow extensive and continuous technology screening and evaluation as an input for systems analysis for emerging technologies.

Methods

The here applied method is inspired by the 'functional technology foresight' approach introduced by Apreda et al. in 2016. In a first step the object of interest and the boundaries of the investigation are defined. Subsequently, functional analysis is used to identify the functions a DACS plant ideally fulfills. It is tested if instead of a full-scale functional map a morphological box is reasonable to depict the results of the functional analysis. An advantage of a morphological box is, that it is more suitable to identify techno-economic parameters based on analogies and changes in a later stage due to its systematic depiction of functions and their technical implementation. Thirdly, Functional Bibliometric Analysis, fed with functions identified in the previous step, is conducted to identify future trends in patents and scientific publications. Within this step it is tested whether Functional Bibliometric Analysis is a powerful tool even though the technology/sector under assessment is still emerging (first technical report on DAC published in 1999 by Lackner et al.). Based on this assessment potential new technologies fulfilling the functions or a change in the function's importance can be identified. This allows statements about possible future technology development in DACS. The link between'functional technology foresight' and systems analysis is realized using the morphological box, which helps identifying the changes between the state of the art and the future developments which are subsequently translated into techno-economic boundary conditions and assumptions for the modelling.

[1] Apreda, R., et al.: „Functional technology foresight. A novel methodology to identify emerging technologies". European Journal of Futures Research 4, Nr. 1 (22. November 2016): 13. https://doi.org/10.1007/s40309-016-0093-1.

[2] Lackner, K., et al.: "Carbon Dioxide Extraction from Air: Is it an Option?". Technical Report LA-UR-99-583, Los Alamos National Laboratory (1999)

Results

Within this publication a systematic approach to allow extensive and continuous technology screening and evaluation as an input for systems analysis is developed and tested on an immature fast developing technology. An intermediate result is the technical status of DACS plants aggregated in a morphological box depicting functions a DACS plant needs to have and possible technical characteristics of available solutions. Furthermore, the above introduced workflow is tested and improved to bring together'functional technology foresight' and systems analysis for emerging technologies/fields. Hereby, it is tested how important parameters for energy systems modelling like investment cost, energy requirements, efficiencies and operational expenditure can be derived.

Effect of the energy crisis on short-term and long-term market design - An economic assessment

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Keywords: market design, energy crisis, policy intervention, power prices, shock

Motivation

Power prices have seen a drastic increase as a result of the energy crisis. This increase was mainly driven by gas prices and differed across European countries. As a result of soaring prices, policy measures have been taken to dampen the effect of the crisis on the economy. The perception of the issue has evolved, leading to different policy responses: The first phase was characterized by a cyclical recovery of gas and power prices due to the recovery from the Covid-19 pandemic and to supply chain inertia which did not engender policy intervention. In the second phase, the Ukrainian war induced a short-term energy supply shock. The overall perception was that European energy markets were facing a short-term supply shock, whose magnitude would be absorbed mostly by focusing on retail price measures. EU countries differed regarding the types of consumers targeted, and the types of measures implemented. Finally, further gas price increases and inflationary pressures changed the perception regarding the duration of the energy crisis and its macroeconomic impact through inflation. The last phase of the crisis, governments felt that structural intervention was required. European countries set broad intervention across retail and wholesale markets to relief customers from high price pressure. With regards to the wholesale market, different market measures were discussed, and windfall profits were finally put in place. The current energy crisis induced a vast debate on short-term and long-term measures, the need of a new market design for the European electricity market and the legacy effect of the crisis. How can EU electricity markets be less exposed to fossil fuel prices? Which measures can promote price stability? How can we structurally support the share of renewables in power generation? My presentation retraces and examines short-term policy interventions during the energy crisis and discusses recently proposed long-term market design changes by the EC.

Methods

My study provides an economic analysis building on research from on-going project work by Compass Lexecon and discussions with relevant decision makers on the projects. First, I present and analyze short-term market interventions across different European countries during the energy crisis. In fact, market movements led to diverse political reactions (or intervention proposals) across legislations to reduce power market wholesale prices. Examples of proposed and implemented market interventions are the market splitting by technologies ("Greece proposal"), fuel-subsidy (as implemented on Iberian market) and the tax on windfall profits. I provide an examination of these measures in the light of economic criteria, i.e. their impact on market functioning (dispatch, storage, DSR, import-exports), investments, security of supply, and distill the lessons learned. Second, I discuss drawbacks and shortcomings of the current European power market design in light of the energy crisis, and how the new market reform proposed by the EC addresses the issues of protecting consumers, strengthening the stability and predictability of energy costs, and stimulating investment in renewable energy. Furthermore, I provide an outlook on possible future market reform needs.

Results

My analysis provides an overview of recently implemented policy measures during the energy crisis and discusses their economic consequences. Furthermore, I provide a qualitative examination of possible drawbacks in the light of the current energy crisis and how they are addressed by the European Commission's market reform proposals of March 2023.