ENERDAY 2024

18th Conference on Energy Economics and Technology

"Exploring Energy Demand Dynamics"

Book of Abstracts

12th April 2024
Dresden

Conference Partners

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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 integration of renewable energy. In our grid area, we want to integrate 100 percent renewable energies securely into the grid and system by 2032 - calculated over the year. The shareholders of 50Hertz are the Belgian 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).

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.

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 **18th 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 18th edition of the ENERDAY, the International Conference on Energy Economics and Technology, with this year's focus on "*Exploring Energy Demand Dynamics*".

The topic in focus relates to various aspects of the demand side:

- The overall development of energy demand,
- demand in different sectors and various energy sources,
- The need for flexibility on the demand side and its impact on the energy system

Increasing flexibility on the demand side contributes to integrating renewable energies and is a prerequisite for well-functioning future energy markets. Further instruments include the short-term response of demand to price signals as well as the necessary expansion of the digital infrastructure. Energy efficiency and sufficiency further underscore the discourse on the demand side, promoting more efficient resource utilisation and facilitating a transformation toward sustainable practices. Topics concerning the impact of the energy price crisis on demand patterns are also of interest, as is the estimation of demand for goods not yet on the market at scale, e.g. hydrogen.
In the spirit of ENERDAY, several questions concerning the topic "*Exploring energy demand dynamics*" are of interest:

- What key drivers will shape energy demand dynamics in the following decades?
- How do socio-economic factors such as population growth and urbanisation influence energy demand patterns?
- What role do technological progress and new (sector coupling) technologies play in shaping energy demand, particularly in sectors such as transportation and industry?
- What flexibility potential results on the demand side in the different sectors, and what regulatory framework is necessary to achieve this?
- What are the implications of shifting consumer preferences and behaviours on energy demand, and what role does demand response play concerning energy prices?

The 18th ENERDAY - Conference on Energy Economics and Technology is being organised primarily as a face-to-face conference with the possibility of hybrid participation. 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. Research on the economics of energy systems is of crucial interest. Empirical analyses, modelling approaches, best practice examples, and policy and market design evaluations are especially relevant contributions to the conference.

The ENERDAY will again 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, which forced us only to be able to select almost every second submitted contribution. We hope you enjoy the program and the high quality of the research presented. We want to thank all the speakers for their contributions and the conference participants for their attendance.

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

Dominik Möst and Christian von Hirschhausen
& EE2 organising committee

ENERDAY 2024 - Exploring Energy Demand Dynamics

18th International Conference on Energy Economics and Technology

Pre-Conference-Dinner Informal Get Together	**Thursday, 11 April 2024, 6 p.m.**	**Augustiner (↗)** An der Frauenkirche 13, 01067 Dresden
Conference venue	**Friday, 12 April 2024, 8 a.m. – 6 p.m.**	**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) **The Power of Flex** Maria Jarolin, Elia Group			
9:45	**5 minutes for change of room**			
Parallel Session 1 (09:50 – 10:50)				
09:50 - 10:50	**Demand response** Room: HSZ/004/H, **hybrid** Chair: Jannis Eichenberg Assistant: Victoria Lehmann	**Hydrogen & natural gas I** Room: HSZ/405/H, **hybrid** Chair: Lauritz Bühler Assistant: Ole Sauerbrey	**Electric vehicle systems** Room: HSZ/403/U, **hybrid** Chair: Maximilian Happach Assistant: Simon Koch	**Energy policies, systems and market designs** Room: HSZ/301/Z, **hybrid** Chair: Lisa Lorenz Assistant: Niklas Haubold
09:50	**Load increase vs. load reduction: the impact of load shifting on the CO2 reduction potential in the context of industrial demand-side flexibility** Nadine Gabrek, *Hochschule Mannheim*	**Techno-economic analysis of long-distance hydrogen transport via high-voltage cables and pipelines: North Sea case study** Veronika Lenivova, *Fraunhofer IEG*	**Time to charge - Charging strategies for a German battery electric truck fleet** Daniel Speth, *Fraunhofer ISI*	**Implications of a potential bidding zone split for the demand allocation in Germany** Lukas Günner, *Aurora Energy Research*
10:10	**Energy demand dynamics considering high RE penetration: managing uncertainties, challenges, and solutions** Rohit Bhakar, *MNIT Jaipur*	**Large-scale evidence of residential natural gas savings through financial rewards** Silvana Tiedemann, *Hertie School*	**Integrating agent-based electric car simulation in energy system optimization – Potential impact of controlled charging and Vehicle-to-Grid on Germany's future power system** Fabio Frank, *Fraunhofer ISI*	**Long term energy policy vs. dynamic public preferences? A review of German energy policy** Jakob Kulawik, *RWTH Aachen*
10:30	**How much flexibility needs to be provided by hydrogen power plants?** Philipp Hauser, *VNG AG*	**Optimizing the distribution of hydrogen production: Evaluation of centralized vs. decentralized approaches from an energy system perspective based on the case of Germany** Nikita Moskalenko, *University of Technology Berlin*	**Modeling synthetic load profiles of future e-truck charging hubs at service stations** Philipp Daun, *RWTH Aachen*	**Paradigm shift in long-term decarbonization scenarios? A review and results of an in-depth analysis of current IPCC data** Björn Steigerwald, *University of Technology Berlin*
10:50	**Coffee & tea break – 25 minutes**			

Parallel Session 2 (11:15 – 12:15)				
11:15 - 12:15	**Energy system modeling I** Room: HSZ/004/H, **hybrid** Chair: Andreas Büttner Assistant: Victoria Lehmann	**Hydrogen & natural gas II** Room: HSZ/405/H, **hybrid** Chair: Philipp Hauser Assistant: Ole Sauerbrey	**Renewable energy outlook** Room: HSZ/403/U, **hybrid** Chair: Dimitrios Glynos Assistant: Simon Koch	**Electricity markets and pricing schemes** Room: HSZ/301/Z, **hybrid** Chair: Hannes Hobbie Assistant: Niklas Haubold
11:15	**Modelling to generate alternatives for decarbonising the energy supply of a large university campus** Katharina Esser, *Ruhr-University Bochum*	**Import costs of green hydrogen via ships for Germany** David Franzmann, *Forschungszentrum Jülich*	**Does cross-border electricity trade stabilize the market value of wind and solar energy? Insights from a European panel analysis** Clemens Stiewe, *Hertie School*	**Preventing winners' default in procurement energy auctions. Theory, simulations and experiments** Silvester van Koten, *University of Jan Evangelista*
11:35	**Drivers of flexibility in a renewable energy system – correlation analysis with a sector-coupled energy system model** Patrick Jürgens, *Fraunhofer ISE*	**A fundamental outlook on European gas fundamentals and price for 2024 / 2025** Andreas Schröder, *ICIS*	**Mine water geothermal energy - abandoned mines as a green energy source** Fritz Raithel, *TU Bergakademie Freiberg*	**Technical aspects of implementing dynamic electricity prices in the context of a local electricity market** Friederike Reisch, *Reiner Lemoine Institut*
11:55	**Welfare redistribution through flexibility - Who pays?** Nils Namockel, *University of Cologne (EWI)*	**Low-carbon hydrogen imports to Europe: Case studies and transformation pathways for ramping up green and blue hydrogen** Nima Farhang-Damghani, *FAU Erlangen-Nürnberg*	**100% renewable energy system in the EU - Implications for infrastructure policy** Niels Kunz, *University of Technology Berlin*	**Identifying elasticities in autocorrelated time series using causal graphs** Jorge Sánchez Canales, *Hertie School*
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) **Exploring residential energy demand dynamics in the context of the energy transition** Prof. Russell McKenna, ETH Zürich			
14:00	**5 minutes to change rooms**			
Parallel Session 3 (14:05 – 15:35)				
14:05 - 15:35	**Energy system modeling II** Room: HSZ/004/H, **hybrid** Chair: Veronika Lenivova Assistant: Victoria Lehmann	**Residential energy systems I** Room: HSZ/405/H, **hybrid** Chair: Jens Maiwald Assistant: Ole Sauerbrey	**Reviewing nuclear power** Room: HSZ/403/U, **hybrid** Chair: Felix Fliegner Assistant: Simon Koch	**District heating transition** Room: HSZ/301/Z, **hybrid** Chair: Hendrik Scharf Assistant: Niklas Haubold
14:05	**~~Energy demands for negative emissions and CO2 supply in future German energy systems~~** (**cancelled**) Thomas Schöb, *Forschungszentrum Jülich*	**Power sector impacts of a simultaneous European heat pump rollout** Alexander Roth, *DIW Berlin*	**Nuclear fusion: An institutional economic analysis of a complex system good** Fanny Böse, *Federal Office for the Safety of Nuclear Waste Management (BASE)*	**What role do CHP plants and electric heat generators play in decarbonised district heating networks?** Matthias Koch, *Öko-Institut*
14:25	**Bridging the supply-demand gap: Techno-economic analysis of Uganda's electricity expansion plan** Galila Khougali (***online contribution***), *University College London*	**Leveraging smart meters to analyze price sensitivity under telescopic tariffs in India** Madhav Sharma (***online contribution***), *Indian Institute of Technology*	**The economic efficiency of non-light water reactors and their non-electrical applications in decarbonized energy systems** Alexander Wimmers, *University of Technology Berlin*	**Flexibility provision in 5th gen district heating systems** Annette Steingrube, *Fraunhofer ISE*
14:45	**Short Coffee & tea break – 10 minutes**			
14:55	**Regional implications for the German electricity system with the energy transition in a European context** Jonas Egerer, *FAU Erlangen-Nürnberg*	**Trade-offs between system cost and supply security in municipal energy system design: an analysis considering spatio-temporal disparities in the Value of Lost Load** Febin Kachirayil (***online contribution***), *ETH Zurich*	**The nuclear paradox in energy scenarios: Exploring nuclear projections and reality** Christian von Hirschhausen, *University of Technology Berlin*	**A case study on long-term investment planning for the decarbonization of Western Europe's most complex district heating network** Stephanie Riedmüller, *Zuse Institute Berlin*
15:15	**Mitigating future variable renewable energy sources curtailment in Poland through demand-side management strategies** Marcin Pluta, *AGH University of Krakow*	**Residential battery flexibility: Spot optimization and ancillary services case study** Prokop Čech, *University of Jan Evangelista*	**The effects of nuclear power plant closures in Germany 2021-2023 on network flows and RE-dispatch – Update of earlier ELMOD modeling results** Enno Wiebrow, *University of Technology Berlin*	**Towards carbon neutrality: Integrated investment and operational optimization for district heating transformation - A case study of Dresden in Germany** Felix Bumann, *SachsenEnergie AG*
15:35	**Coffee & tea break – 25 minutes**			

Parallel Session 4 (16:00 – 17:30)				
16:00 - 17:30	**Energy and society** Room: HSZ/004/H, **hybrid** Chair: Jakob Baumgarten Assistant: Victoria Lehmann	**Residential energy systems II** Room: HSZ/405/H, **hybrid** Chair: Lucas De La Fuente Assistant: Ole Sauerbrey	**Household PV systems** Room: HSZ/403/U, **hybrid** Chair: Felix Meurer Assistant: Simon Koch	**Advanced modelling and weather analysis** Room: HSZ/301/Z, **hybrid** Chair: Martin Kittel Assistant: Niklas Haubold
16:00	**How to get photovoltaics on the roofs? Empirical evidence on the public support for a residential solar mandate in Germany** Tom Schütte, *University of Kassel*	**Evaluating district energy systems: Central vs. decentral batteries in dynamic electricity pricing** Karl Seeger, *RWTH Aachen*	**Prosumers with PV-battery systems in the electricity markets** Felix Meurer, *University of Duisburg-Essen*	**A binary expansion approach for the water pump scheduling problem in large and high-altitude water distribution networks** Denise Cariaga, *The University of Edinburgh*
16:20	**Implications of energy justice for energy system modelling – Public acceptance's impact on renewable energy implementation.** Jonathan Hanto, *University of Technology Berlin*	**Does knowledge of CO2 prices impact homeowners' choices? An analysis of energy retrofit preferences in Germany** Simon Pröse, *University of Kassel*	**Household responses to the tax treatment of income from solar PV feed-in in Germany** Reinhard Madlener, *RWTH Aachen*	**Variable renewable energy droughts in the power sector – a model-based analysis and implications in the European context** Martin Kittel, *DIW Berlin*
16:40	**Short Coffee & tea break – 10 minutes**			
16:50	**Bioenergy production and local acceptance - Quasi-experimental evidence on the impact on residential property values** Shanmukha Srinivas Byrukuri Gangadhar, *Brandenburg University of Technology*	**Residential electricity consumption patterns in northwestern Switzerland** Valentin Favre-Bulle, *University of Neuchâtel*	**enerWARD: Corporate sustainable bonds: Determinants of the Greenium** Christoph Sperling, *TU Dresden*	**High-resolution modeling of heating-cooling demand under future climate change scenarios** Camila Villarraga Díaz, *German Aerospace Center (DLR)*
17:10	**Exploring pathways for progressing renewable energy communities in Poland: Insights from comprehensive interviews** Anna Kowalska-Pyzalska & Ewa Neska, *Wroclaw University of Science and Technology*	~~**Overcoming the landlord-tenant dilemma: a techno-economic assessment of collective self-consumption for European multi-family buildings**~~ (cancelled) Russell McKenna, *ETH Zürich*	~~**Solar prosumage: Interactions with the transmission grid**~~ (cancelled) Mario Kendziorski, *University of Technology Berlin*	**Electricity markets in a fully decarbonized economy** Frank Heinz, *RWTH Aachen*
17:30	**End of parallel Sessions**			
17:45	**Group picture at the TU-Logo in front of the HSZ (↗)**			
18:00	**Bus transfer to gala dinner (departing from Mommsenstraße)**			

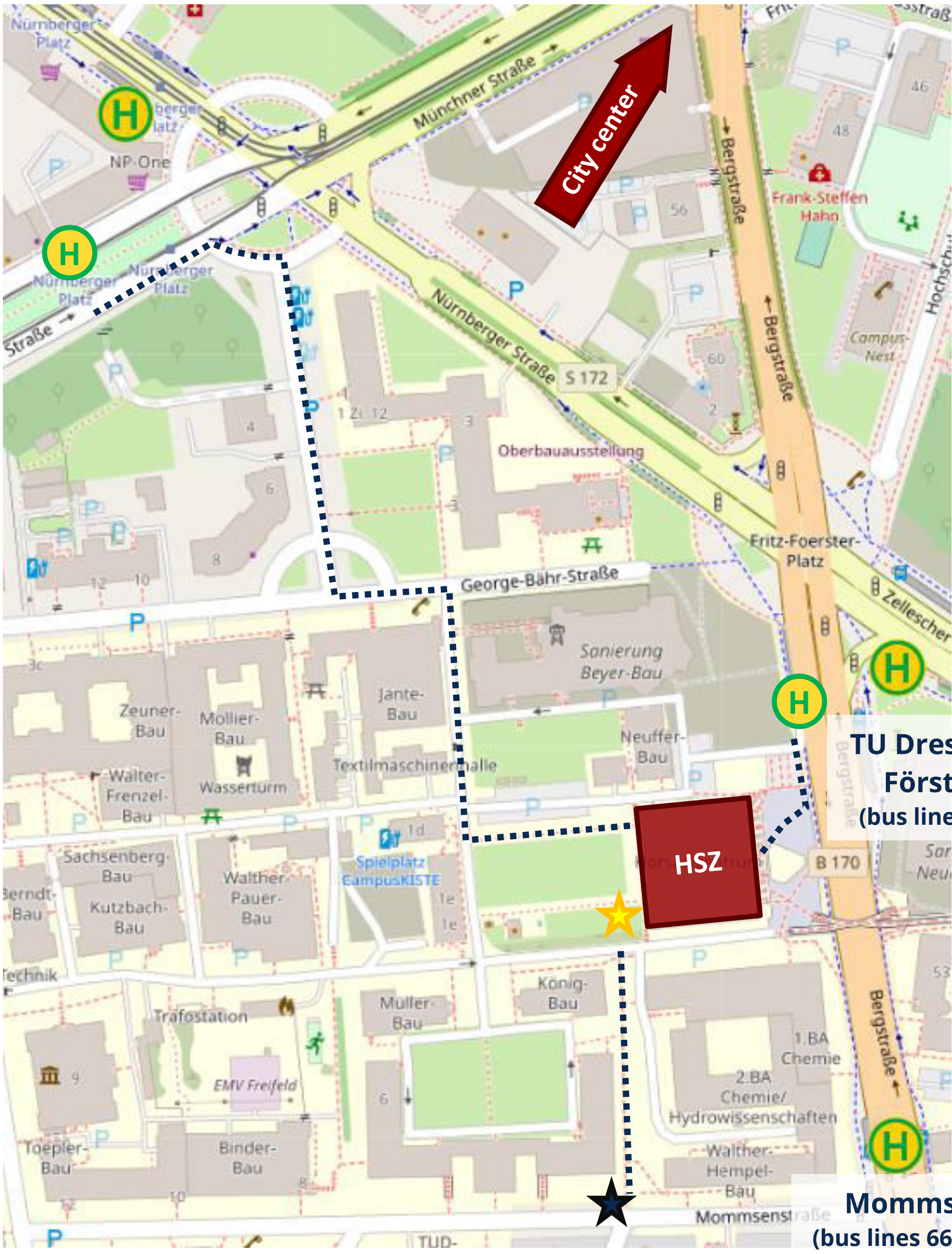
Gala Dinner Official closing event and award ceremony	**Friday, 12 April 2024** **18:45 p.m.**	**Spitzhaus Radebeul (↗)** Spitzhausstraße 36, 01445 Radebeul

23:30	**Bus transfer to Dresden central train station (departure from the gala dinner location)**

ENERDAY 2024 - Venue and floor plan

Campus Navigator (↗)

Directions



TU Dresden/Fritz-Förster Platz
(bus lines 61, 63, 66)

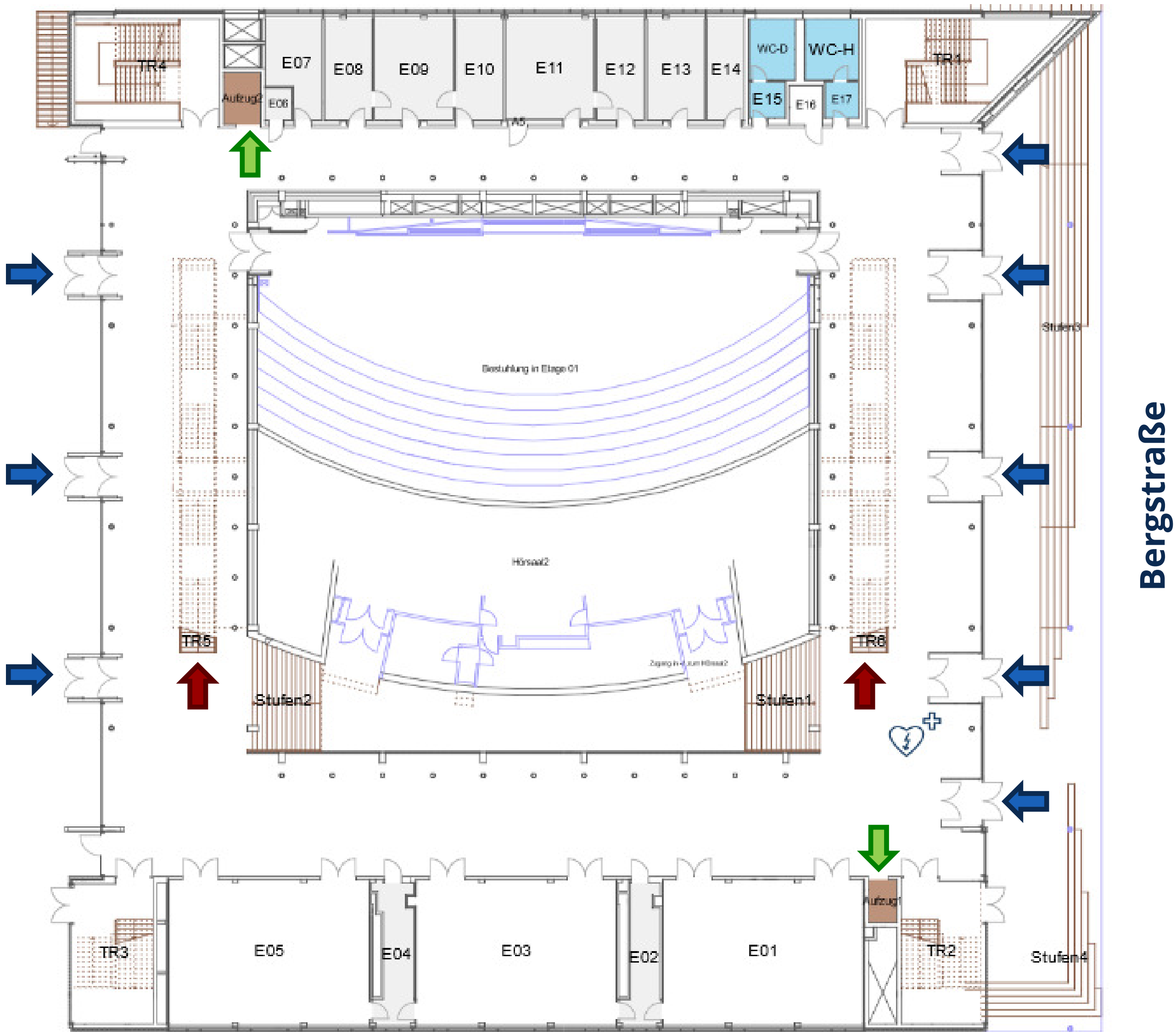
Mommsenstraße
(bus lines 66, 352, 360, 366)

- Tram/Bus stations
- Conference location (HSZ - Hörsaalzentrum)
- Location for the group picture
- Departure for the gala dinner

ENERDAY 2024 - Venue and floor plan

Campus Navigator (↗)

Ground floor (building entry)



Building entrance

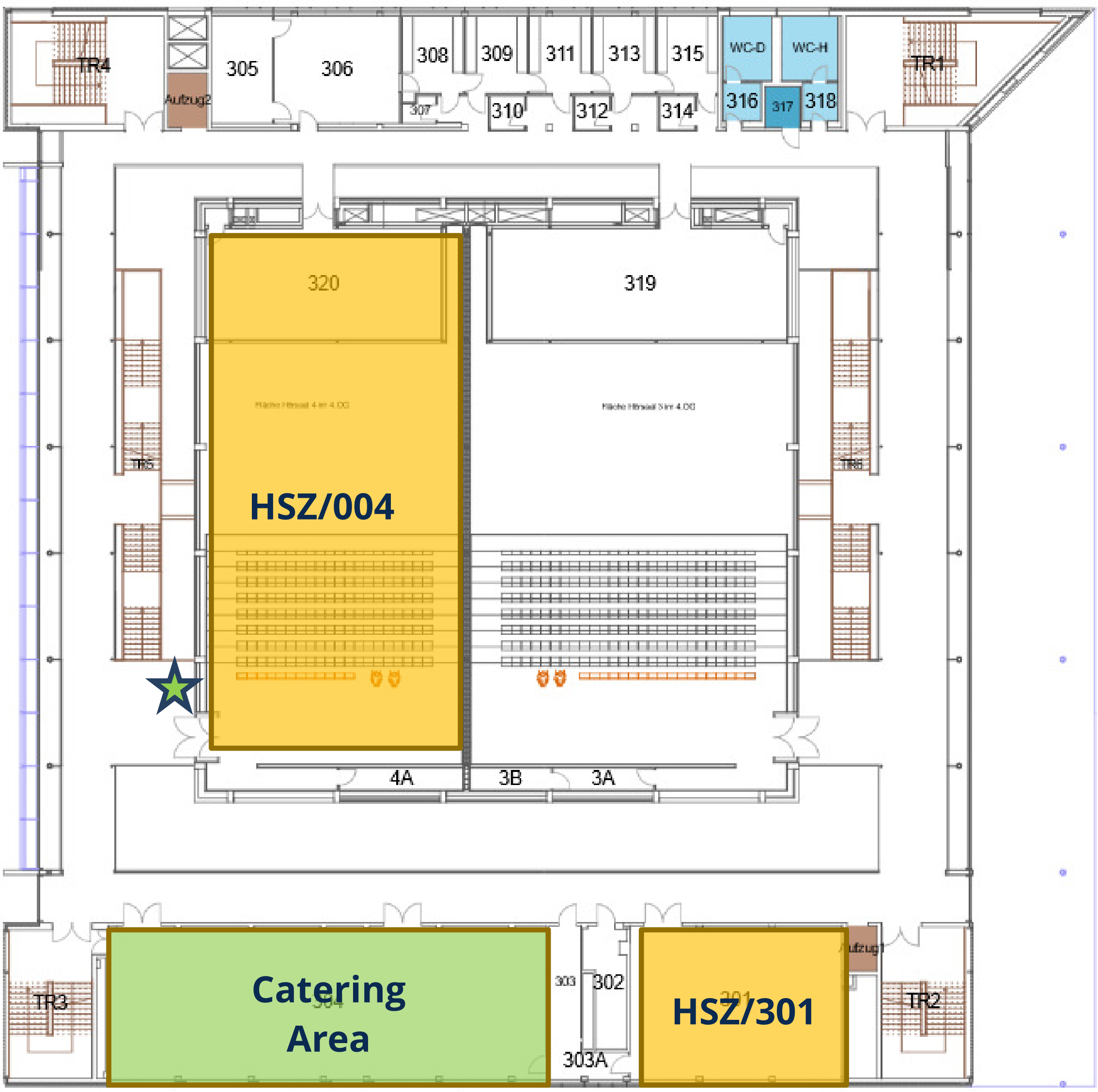
Staircase to reach the conference office at the 3rd floor

Elevator

ENERDAY 2024 - Venue and floor plan

Campus Navigator (↗)

Conference floor – 3rd floor



Conference Rooms

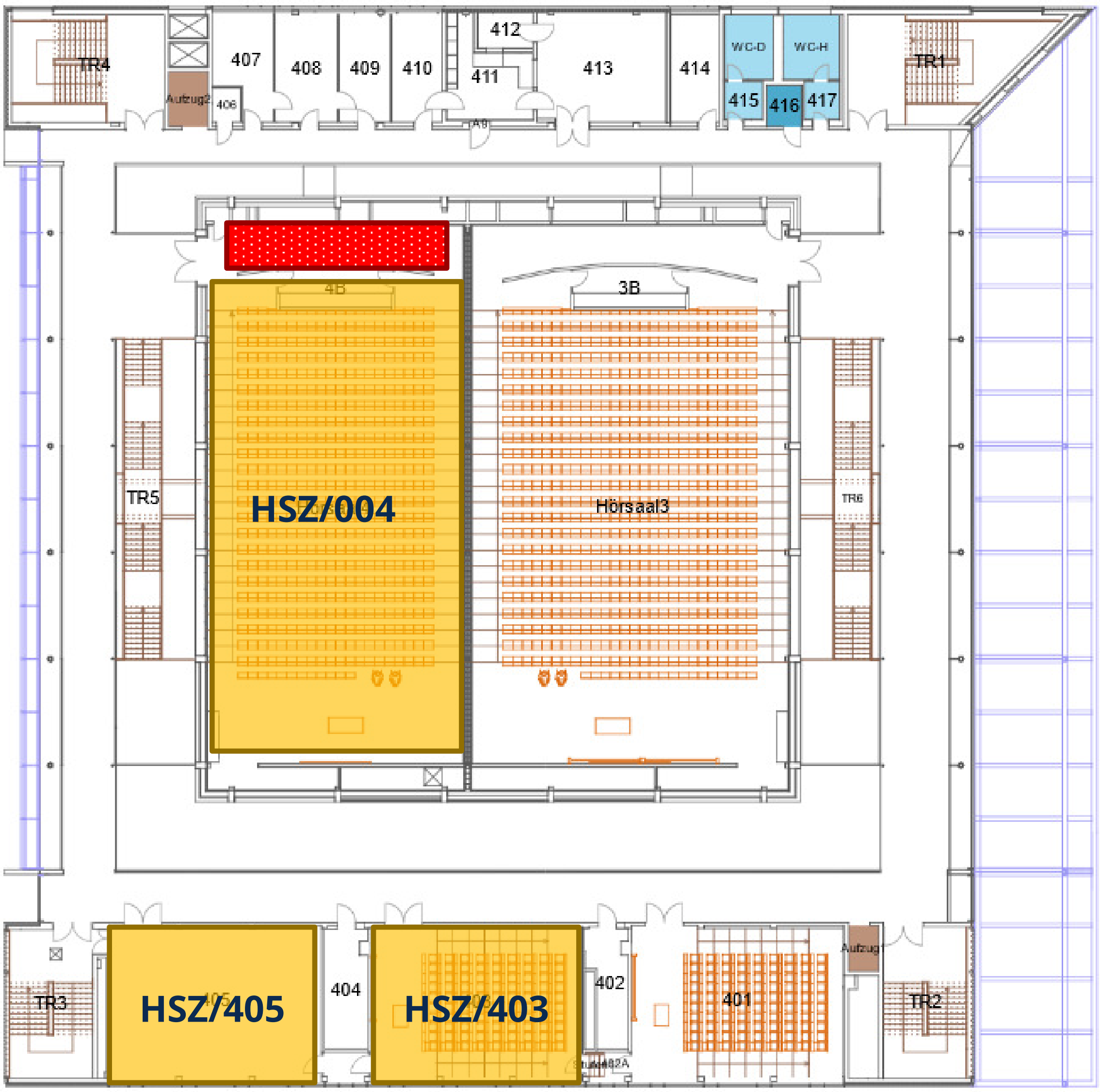
Catering Area

Conference Office

ENERDAY 2024 - Venue and floor plan

Campus Navigator (↗)

Conference floor – 4th floor



Conference Rooms

Wardrobe

Content

Keynote I 9:00 – 9:45

Room: HSZ/004/H, hybrid
Chair: Prof. Dr. Dominik Möst

The Power of Flex

Maria Jarolin[1]

[1]*Elia Group*

Session 9:50 – 10:50
Demand response

Room: HSZ/004, hybrid
Chair: Jannis Eichenberg

Load increase vs. load reduction: the impact of load shifting on the CO2 reduction potential in the context of industrial demand-side flexibility

Nadine Gabrek, *Hochschule Mannheim*

Energy demand dynamics considering high RE penetration: managing uncertainties, challenges, and solutions

Rohit Bhakar, *MNIT Jaipur*

How much flexibility needs to be provided by hydrogen power plants?

Philipp Hauser, *VNG AG*

Load increase vs. load reduction: the impact of load shifting on the CO2 reduction potential in the context of industrial demand-side flexibility

Nadine Gabrek[1] (Speaker), Lena Ackermann[2], Stefan Seifermann[3]

[1]*Hochschule Mannheim, n.gabrek@hs-mannheim.de*
[2]*Hochschule Mannheim, lenanora.ackermann@stud.hs-mannheim.de*
[3]*Hochschule Mannheim, s.seifermann@hs-mannheim.de*

Keywords: industrial demand flexibility, CO2 reduction potential, cost reduction potential, load increase, load reduction

Motivation

The energy transition in Germany includes an increased expansion and integration of electricity generation by renewable energy sources in order to replace CO2-intensive generation technologies. Nonetheless, the volatility of renewable energy requires different flexibility measures, like industrial demand flexibility, to ensure the stability of the energy system.

Industrial demand flexibility measures can further contribute to an indirect reduction of CO2 emissions by shifting electricity consumption from periods with high emissions to periods with lower emissions. Consequently, such measures support the reduction of emission-intensive electricity generation, while simultaneously promoting the efficient use of climate-friendly generation technologies.

A conservative estimation by Zachmann & Seifermann [1] reveals a total reduction potential for CO2 emissions through industrial demand flexibility of approximately 700,000 tons of CO2. In the future, this potential will increase until 2030, while it will decline moderately until 2050. An increasing significance of single emission peaks due to remaining fossil power plants is identified as the main cause of the CO2 avoidance potential of industrial demand flexibility, even in the future. Therefore, the hypothesis can be derived that short-term load reduction will play an increasing role in the future energy system, while short-term load increase will be of subordinate importance. Thus, this work investigates the hypothesis by evaluating industrial demand flexibility potential with the help of a quarter-hourly modeling of future electricity generation and the associated CO2 emissions and costs of electricity procurement.

Methods

Data from a survey of the potential of industrial flexibility measures, which was carried out as part of the Kopernikus project SynErgie, forms the basis of this analysis. To verify the hypothesis, only flexibility measures that allow a combination according to their technical characteristics and design are analyzed.

The aggregation of the CO2 emissions and their reduction potential is conducted according to Zachmann & Seifermann [1] and is further extended by a calculation of the associated potential cost savings. To estimate the future potential, German electricity mix scenarios are defined based on selected studies for 2030 and 2045 and broken down to a quarter-hourly level using a simplified electricity generation model, which was expanded by a modulation of electricity prices.

First, the CO2 emissions of the electricity mix are determined using emission factors of the individual generation technologies. The avoidance of emissions from industrial flexibility measures results from shifting work from periods with high specific emissions to periods with low emissions. This work is caught up in periods with average emissions. The CO2 reduction for each measure are calculated for every quarter of an hour. Taking time restrictions of the individual measures into account, blocks with the length of a retrieval cycle are defined to determine the highest possible CO2 avoidance for each cycle. Finally, the annual CO2 reduction potential is aggregated from the largest values of the individual blocks according to the retrieval frequency. The analog aggregation of the electricity prices from the marginal costs of power plants via the merit-order approach, further enables the derivation of the quarter-hourly cost savings of the CO2-optimized view and consequently the evaluation of the hypothesis from an economic point of view.

Results

A comparison of the considered industrial demand flexibility measures, with regard to the target years 2030 and 2045, clearly indicates that the share of load reduction in the CO2 emissions reduction potential and the possible cost savings is superior in the beginning but decreasing. Load reduction has a share of 78% in 2030, which diminishes to 56% in 2045. This is due to the fact that the severity and frequency of CO2 emission peaks is decreasing as well. Nevertheless, the CO2 avoidance potential of load reduction is overall higher in both future scenarios than that of load increase.

Considering the associated cost savings, load increase signals a higher economic potential in the future as the intra-year analysis shows an increasing share of flexibility measures with load increase in the comparison of the target years. While the total potential savings for measures with load reduction decrease, the total cost savings of load increase measures remain constant. This leads to a rise in the share of load increase measures from 40% in 2030, to 66% in 2045. Among other things, this can be attributed to the price range determined by the price modeling and the applied methodology to shift work to average costs.

With regard to the initial hypothesis, it can be stated that the trimming of CO2 emission peaks through load reduction will continue to present a high potential for reducing CO2 emissions in the future. Any further application of flexibility measures is associated with lower CO2 avoidance, both for measures of load reduction and load increase. From an economic perspective, on the other hand, a higher potential for cost reduction was identified when using load increase.

[1] Zachmann, Bastian; Seifermann, Stefan: CO2-Vermeidungspotential beim Einsatz von Maßnahmen industrieller Nachfrageflexibilität; In: IEWT 2021; online verfügbar unter: https://iewt2021.eeg.tuwien.ac.at/download/contribution/fullpaper/104/104_fullpaper_20210905_220401.pdf.

Energy demand dynamics considering high RE penetration: managing uncertainties, challenges, and solutions

Ajay Kumar Verma[1], Dr. Anjali Jain[2], Rohit Bhakar[3] (Speaker)

[1]*MNIT Jaipur*
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Keywords: Energy Demand Dynamics, Power to Hydrogen, Energy Storage

Motivation

The dynamics of energy demand is gradually increasing due to high penetration of renewable energy (RE) into the grid. Energy dynamics impact the stability and reliability of the electricity grid. The system's stability is affected by several challenges, such as scheduling and reserve margins in system operation and planning, primarily due to the variability and intermittency of RE sources. The study explores the intricate interplay between demand dynamics and high penetration of renewable energy (RE). This study highlights possible solutions implemented globally that effectively address these challenges, including supply-demand balancing considerations in India's highly RE-integrated systems. These solutions include the installation of hybrid solar and wind plants, integration of energy storage, power-to-alternative energy (Power-to-X: alternative storage technologies), and new market design considering the high RE. Managing demand dynamics requires effective coordination between supply-side solutions, energy storage/ hydrogen storage and demand response. Ensuring seamless interaction between demand-side and supply-side resources is crucial for maintaining grid stability and reliability. The study's main aim is to provide a comprehensive overview of demand dynamics in the context of high RE penetration, examining uncertainties, solutions, and challenges inherent in this evolving energy landscape worldwide. The insights will provide an improved portfolio of options for India to manage demand dynamics in the high RE penetration grid.

How much flexibility needs to be provided by hydrogen power plants?

Philipp Hauser[1] (Speaker), Christoph Brunner[2], Steffi Misconel[3]

[1]VNG AG, philipp.hauser@vng.de
[2]EnBW
[3]EURAC Research

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

Motivation

The German government aims to achieve a carbon-neutral power system by 2035 and published a power plant strategy in February 2024. The overall objective is to create 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 – much more than stated in the current power plant strategy, where only 10.5 GW are announced - 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
Hydrogen & natural gas I

Room: HSZ/405/H, hybrid
Chair: Lauritz Bühler

Techno-economic analysis of long-distance hydrogen transport via high-voltage cables and pipelines: North Sea case study
Veronika Lenivova, *Fraunhofer IEG*

Large-scale evidence of residential natural gas savings through financial rewards
Maximilian Amberg, *Mercator Research Institute*

Optimizing the distribution of hydrogen production: Evaluation of centralized vs. decentralized approaches from an energy system perspective based on the case of Germany
Nikita Moskalenko, *University of Technology Berlin*

Techno-economic analysis of long-distance hydrogen transport via high-voltage cables and pipelines: North Sea case study

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Keywords: energy system modeling, hydrogen pipelines, HVDC, HVAC, economies of scale

Motivation

In the transition towards a decarbonized energy landscape, renewable hydrogen-based technologies emerge as a pivotal component for a sustainable energy system. However, the constraints of renewable hydrogen production, both geographical and temporal, may not always align with the demands of end-use sectors and with location and availability of underground hydrogen storage facilities. It is important to consider these limitations when evaluating the feasibility of renewable hydrogen as a long-term energy solution. Consequently, there is a clear need to transport hydrogen over long distances. This raises a fundamental question about the optimal mode of transportation: should hydrogen be transported via long-distance pipelines, or should electrolysers be located close to consumers, with renewable energy transmitted via electricity cables such as HVDC and HVAC? The growing interest in hydrogen pipeline infrastructure, particularly in Europe has generated numerous reports and policy documents (EHB 2023, DNV 2023), creating a strong sense of urgency among infrastructure developers to make investment decisions in the near future. However, this landscape is characterised by uncertainty and high-risk factors, making infrastructure planning difficult. This study is being conducted as part of the MOHN research project funded by the BMBF in cooperation with cruh21.

Methods

This study is based on the research presented by Patonia et al. (2023), which was the foundation for our investigation. Through a comprehensive literature review focusing on the specific costs associated with pipeline and cable transport, we have found that for hydrogen demand in the industry sectors, pipeline transport over longer distances tends to be more economical than high voltage electricity lines. However, the process of making decisions about infrastructure selection is complex and influenced by various factors. To address this complexity, we aim to use energy system models to analyze a range of multi-dimensional factors and their impact on gas infrastructure deployment. Our research employs the PyPSA-Eur model in this regard. Several challenges exist in this approach, including issues related to the linearity of economies of scale in linear programming (LP) models, solvability concerns for non-LP models, and the sensitivity of cost assumptions. To address these challenges, we propose a methodological framework that is focused on enhancing the efficacy of infrastructure planning processes. This case study examines the impact of different cost input parameters, specifically capital expenditure, on the feasibility of pipeline and cable infrastructure in a greenfield scenario in overnight and myopic optimization approach for years 2030, 2040 and 2050. Additionally, we intend to conduct a simplified optimization exercise utilizing the North Sea as a demonstrative example, exploring the cost dynamics associated with hydrogen backbone infrastructure. In the end, we compare the economic viability of North Sea originated hydrogen with other import options from the latest energy atlases and available literature.

Results

Our preliminary findings aim to provide insights into real-world infrastructure planning, using the North Sea region as an example. We are addressing critical questions, such as the economic viability of hydrogen transport over varying distances and the role of the two aforementioned transportation options. By exercising economies of scale for capacity planning of long-distance networks, a clearer vision of the development of offshore hydrogen infrastructure can be presented based on existing project data. This research also highlights the potential for offshore hydrogen production and its role in ensuring security of supply, which can lead to discussions on the competitiveness of domestic renewable hydrogen production versus imports.

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Large-scale evidence of residential natural gas savings through financial rewards

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Keywords: energy savings, financial incentives, information treatments, selection bias, European energy crisis, graphical inference, directed acyclic graph

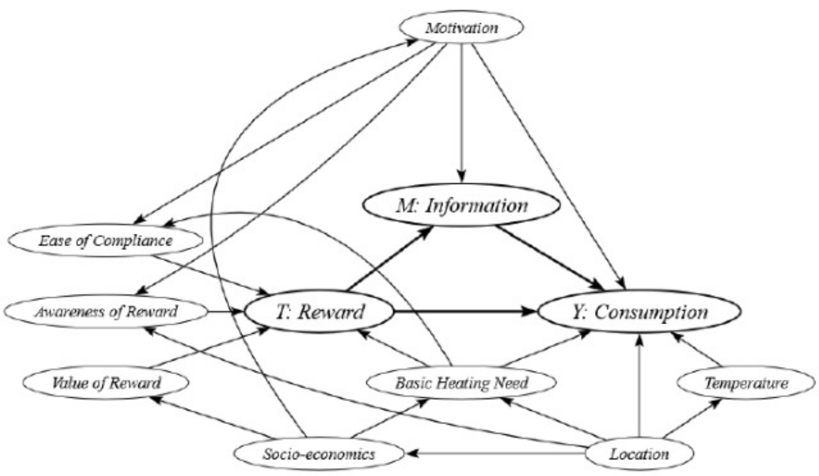
Motivation

Energy crises have a major impact on the economy, although they are often temporary. The oil crises of the 1970s for example had a significant impact on the global GDP, the cold snap in Texas in winter 2021 caused outages of the electricity system, and there were legitimate concerns in Europe that there would be gas shortages and rationing in the winter of 2022/23. As climate change progresses and due to the high degree of international interdependence between countries, situations requiring temporary reductions in energy consumption may become more common. This raises the question of how policy makers and energy suppliers can respond in the short term to persuade customers to (temporarily) reduce their consumption. This paper examines the influence of a gas saving reward program on household energy consumption set up by one of Germany's major energy utilities during the European energy crisis in 2022/23. Unlike typical settings where energy utilities lack incentives to promote energy savings, crises often see prices which are higher than predicted. Hence, utilities can financially benefit from their customers consuming less than predicted. Furthermore, an expert advisory panel to the government recommended introducing gas saving reward programs as a dual strategy to lower energy usage and compensate households (Expert Commission on Gas and Heating, 2022). Currently, we are aware of more than 10 utilities in Germany that henceforth implemented gas saving reward programs. However, which types of customers get attracted by these programs and whether such financial incentives are effective in reducing households' gas consumption remain open questions. Furthermore, the relative importance that different mechanisms behind the total effect have is unclear: apart from the direct response to the financial incentive, an indirect information treatment due to increased engagement of program participants with their own gas consumption might play a crucial role.

Methods

To evaluate the program, which financially rewarded households for reducing their temperature-adjusted gas consumption during the 2022/23 heating period by at least 10 percent compared to the previous year, the energy utility granted access (under the condition that it may not be named) to rich and unique customer- and contract-level data. Using geocoded delivery addresses, we combine these billing records from the universe of residential customers of the utility with various supplementary types of data, including information on weather conditions as well as socio-demographic household characteristics and building attributes. In a first step, we use this unique database to provide descriptive statistics on the characteristics of participating and non-participating households. In a second step, we estimate the causal effect of interest – the average treatment effect on the treated (ATT). To credibly defend the conditional independence assumption, we summarize our identification assumptions in a directed acyclic graph (DAG), which is particularly suited to express causal links in an observational setting (Pearl, 2000) [Figure 1]. The regression analysis paired with (exact) matching accounts for households selecting into treatment for non-random, systematic reasons (which we either directly observe or proxy for using our rich tracking data on the pre-intervention engagement of customers with information on their energy consumption). Specifically, we report estimates based on three different comparison groups. First, we present estimates from regressions using the full, unadjusted sample of non-participating households. Second, we compare them with results estimated using two different matching variants which we set up based on our DAG. To demonstrate that our two matching variants achieve covariate balance, we contrast the pre-matching with the post-matching (im-)balance in so-called LOVE plots [Figure 2].

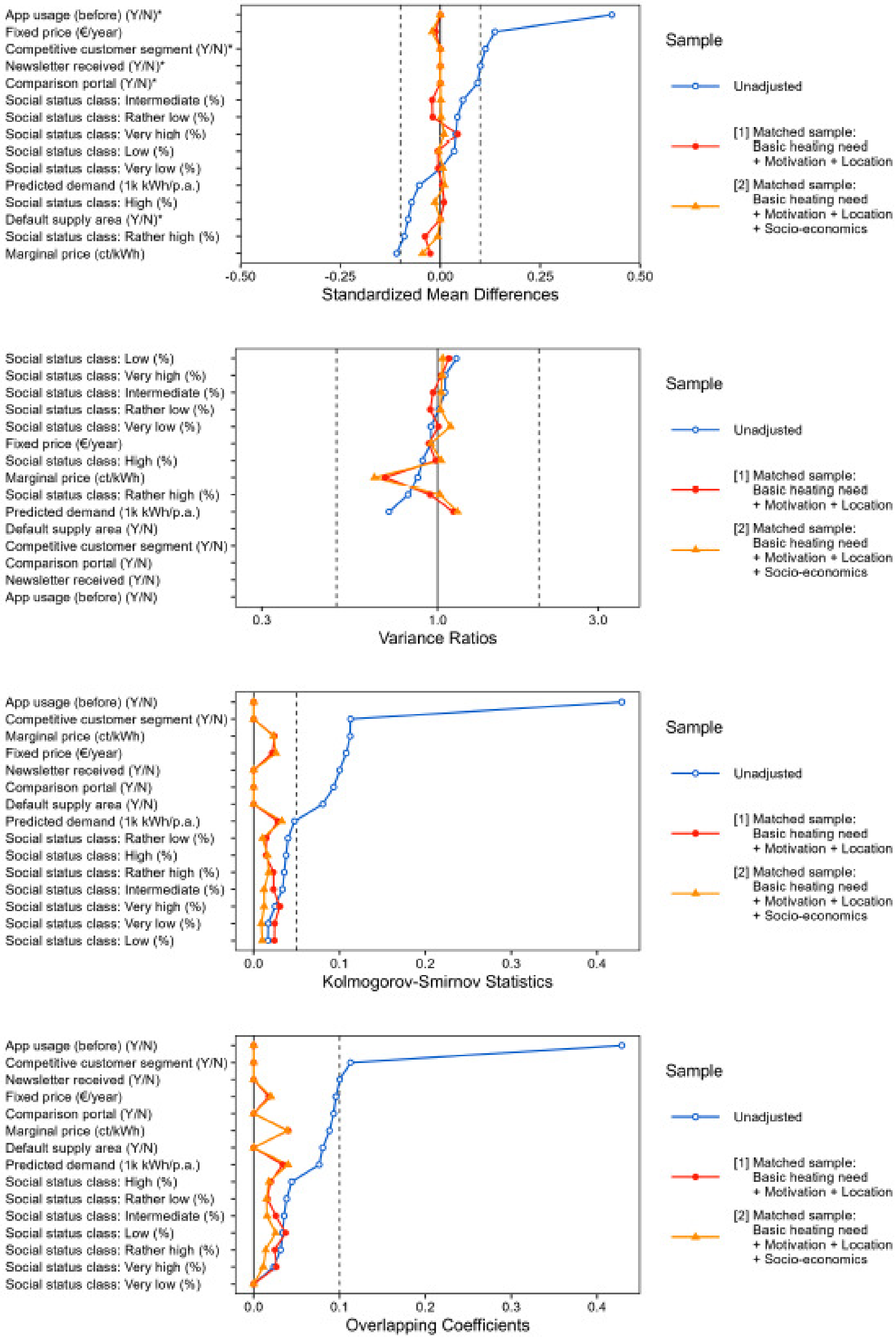
Figure 1: The Causal Effect of the Program on Consumption: Graphical Representation



Source: Own illustration created via causalfusion.net (see Bareinboim and Pearl, 2016).

Figure 1

Figure 2: Covariate Balance:
LOVE Plots on Main Variables



Notes: The asterisk * signifies dummies with raw/non-standardized mean differences. The shares of households by social status class are measured in percent per zipcode (Acxiom, 2020).

Figure 2

Results

Our descriptive analysis reveals that households selecting into treatment are more active and motivated, already prior to the program. We use the DAG to illustrate that selection into treatment is the main identification challenge and how it can be addressed.

Our main (matching) results indicate that participants reduce their gas consumption by a robust and significant 3.2 cubic meter per heating day compared to the matched non-participating households (equivalent to around 5.4 percent) [Figure 3]. Not accounting for the selection bias would lead to an estimated reduction of 5.2 cubic meter per heating day, overestimating the preferred ATT estimate by more than 80 percent. Our results are robust to a series of sensitivity checks, including i) pseudo-treatments, ii) different choices of controls in the outcome model, iii) additional comparisons groups, iv) a different construction of our outcome variable, v) the inclusion of temperature controls, and vi) the use of a more stringent sample.

Until the conference, we are working on several extensions of the analysis. First, we are implementing machine learning (ML) tools for the prediction of program participation (in the fashion of Hut and Oster, 2022) to shed more light on the group of customers being responsive to financial treatments. Second, we are further validating the results by comparing our estimate with the results from the double ML estimator (see Knaus, 2022; Bach 2023), and conducting a pseudo-treatment test with the customer data of the utility's sub-brand. Third, we are analyzing the effect of the program on the heterogeneous customer groups, exploiting the rich socio-economic characteristics of customers further. The heterogeneity will also be used to make suggestions on a better targeting of the policy in case of budgetary limitations. Lastly, we are conducting a mediation analysis to distinguish the effect of the direct financial incentive from the related indirect information treatment.

Table 1: The Effect of the Program on Consumption:
Main Estimates

	Unadjusted sample			Matched samples	
	U-0	U-1	U-2	M-1	M-2
$\mathbb{1}$[Reward]	−0.59*** (0.04)	−0.40*** (0.02)	−0.40*** (0.02)	−0.35*** (0.04)	−0.32*** (0.04)
Matched sample				[1]	[2]
Control sets:					
· Basic heating need (B_i)		✓	✓	✓	✓
· Motivation ($\mathbf{M}_i$)		✓	✓	✓	✓
· Location ($\mathbf{L}_i$)		✓	✓	✓	✓
· Socio-economics ($\mathbf{S}_i$)			✓		✓
Effect estimate (in %)	-9.5	-6.6	-6.6	-5.9	-5.4
N	28 847	28 847	28 847	12 312	12 314
R^2	0.01	0.75	0.75	0.77	0.77
R^2 within		0.73	0.73	0.75	0.75

Notes: (i) ***, **, *, and . represent 0.1%, 1%, 5%, and 10% significance levels, respectively; (ii) robust standard errors in parentheses; (iii) the dependent variable is the gas consumption measured in m^3 per heating day.

Figure 3

Optimizing the distribution of hydrogen production: Evaluation of centralized vs. decentralized approaches from an energy system perspective based on the case of Germany

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Keywords: Energy system modeling, Hydrogen, Infrastructure, Distribution, Germany

Motivation

As a crucial element for the energy transition - especially in hard-to decarbonize sectors, hydrogen will most likely hold a key role in the European energy system. With the REPowerEU plan aiming for a domestic hydrogen production of 10 Mt by 2030, member states are preparing for their own national hydrogen strategies. Regarding the optimal distribution of hydrogen production sites however, discussion around centralized or decentralized production arises. Central production of hydrogen can benefit from i.e. high potentials of offshore wind energy. Furthermore, electrolysers can be used as a flexibility option, when electricity would otherwise be curtailed, especially in close vicinity to offshore wind power, where high wind speeds yield high-capacity factors. Decentral production close to demand sites on the other hand can reduce transportation costs of hydrogen substantially. Moreover, waste heat from electrolysers can be directly used in low-temperature industry processes or district heating for buildings. In this paper, the influence of multiple techno-economic factors on the balance between central and decentral hydrogen production is to be analyzed with Germany as an exemplary case study. The results shall give insight into key indicators to decide whether a centralized or decentralized hydrogen production is more beneficial to the overall energy system and serve as a guideline for policymakers and stakeholders around Europe.

Methods

For this paper, the newest version of the Global Energy System Model (GENeSYS-MOD) is used for the optimization of the German energy system and the distribution of hydrogen production within the country. GENeSYS-MOD is a linear open-source energy system model minimizing costs to analyze low-carbon energy transition pathways. To represent a sector coupled energy system and reach deep decarbonization, the model considers the four sectors electricity, buildings, industry, transport, and their interdependencies. A stylized version of the model's structure can be found in figure 1.

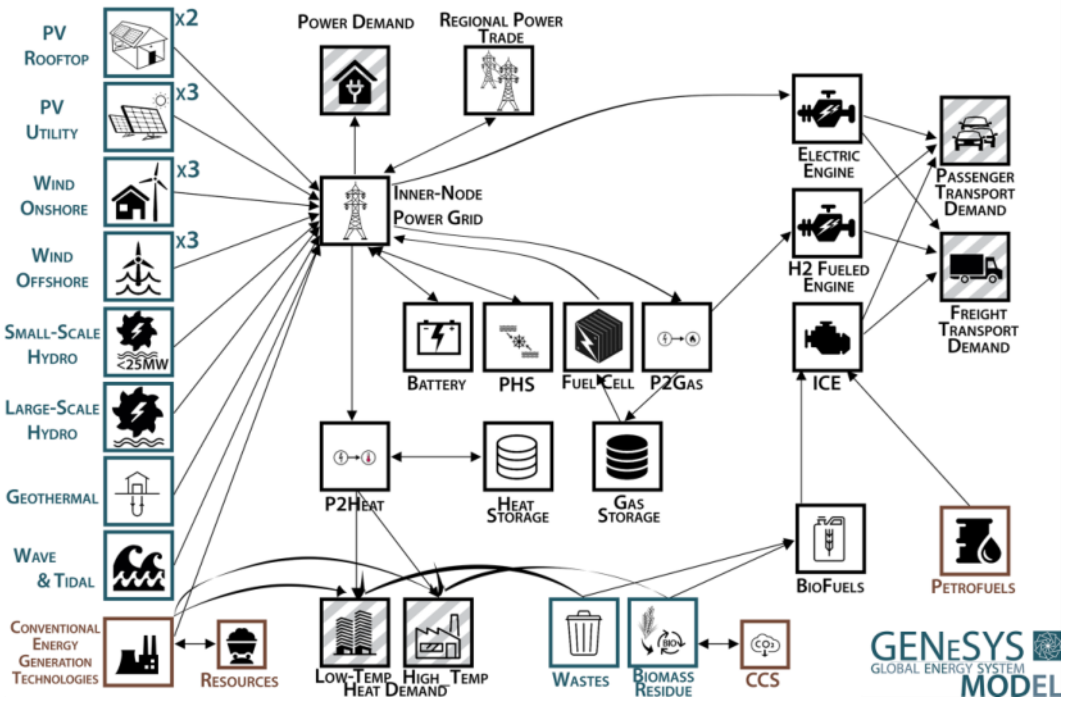

Figure 1

As a setting and to follow the current hydrogen expansion plans of the EU, the most recent German policy developments, such as the Osterpaket and the coal and nuclear exit, are incorporated into the model, aiming to reach net-zero emissions by 2045. Furthermore, expansion plans for offshore wind capacities are included to enable the potential for centralized hydrogen production in the North and Baltic Sea. Germany is divided into its 16 federal states to take into account regional industrial demand sites and thoroughly analyze the distribution of electrolysers. To achieve a distinct representation of possible centralized hydrogen production, two offshore nodes (North Sea and Baltic Sea) are implemented in the model. This enables the assignment of specific time series, especially for offshore wind potential, whereas the potential of coastal federal states could be reduced in order to not overestimate the overall offshore wind potential. Furthermore, the two nodes are only able to build offshore wind and electrolyser capacities to analyze potential influences on the optimal distribution of hydrogen production. Sensitivity analyses in regard to transport costs of hydrogen and electricity as well as capital costs of electrolyers shall give more insights into the decision of the production sites.

Results

Preliminary model results favor a central production of hydrogen from an economic perspective, leveraging wind-power in the North and Baltic Sea as can be seen in figure 2. Hydrogen is then distributed across Germany via the existing gas-pipelines and towards 2050 increasingly via dedicated hydrogen pipelines. This is however to a great degree dependent on the chosen cost assumptions for the technologies and fuels. Production moves closer to the location of use (often regions with high industrial demand) when advancements, such as usage of heat from electrolysers, are added to the model. Sensitivity analyses further show an increasing decentralization with lower capital costs for electrolysers. However, more sensitivities on the transport costs of electricity and hydrogen are necessary to conclude the analysis. We are expecting to see a change in the production distribution based on cost assumptions for transport of electricity and hydrogen, as well as capital costs of electrolysers. With the analysis of the sensitivities, specific break points in the cost assumptions are to be extracted and different price combinations are to be determined to give a first evaluation of when a central or decentral hydrogen production is most beneficial for the energy system. While a first estimate can be made however, more factors such as the distribution of industrial sites and overall renewable potential can be influential for the decision. Thus, further research on different regional cases is necessary. Furthermore, transnational hydrogen trade and production can greatly influence findings and should be carefully evaluated and researched in future efforts.

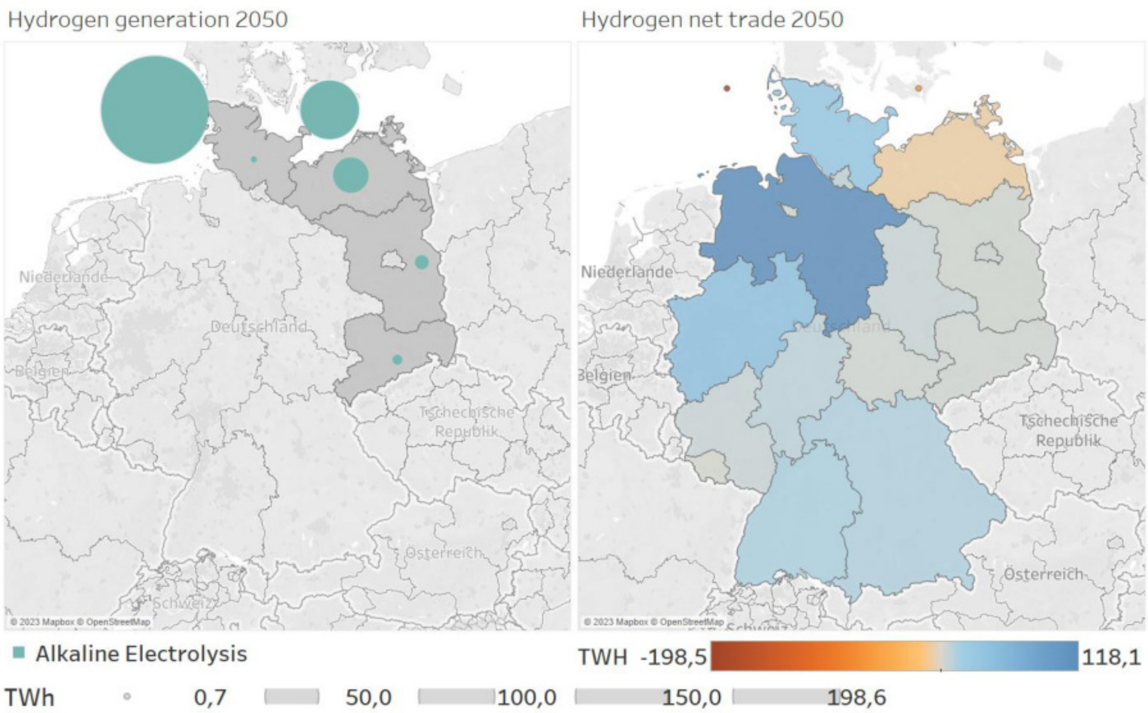

Figure 2

Session 9:50 – 10:50
Electric vehicle systems

Room: HSZ/301/U
Chair: Maximilian Happach

Time to charge - Charging strategies for a German battery electric truck fleet
Daniel Speth, *Fraunhofer ISI*

Integrating agent-based electric car simulation in energy system optimization – Potential impact of controlled charging and Vehicle-to-Grid on Germany's future power system
Fabio Frank, *Fraunhofer ISI*

Modeling synthetic load profiles of future e-truck charging hubs at service stations
Philipp Daun, *RWTH Aachen*

Time to charge - Charging strategies for a German battery electric truck fleet

Daniel Speth[1] (Speaker), Saskia Paasch[2]

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Keywords: electric mobility, trucks, battery electric trucks, load profile, demand simulation

Motivation

Heavy-duty vehicles (> 12 t) represent less than 5 % of the European vehicle fleet, but are responsible for 15 - 22 % of CO2 emissions from road transport in 2019. Climate neutrality also requires ambitious measures in the transport sector. Electrification is increasingly becoming an option for heavy-duty vehicles. The first vehicles are already available and more models have been announced. European manufacturers expect about half of all trucks sold in 2030 to be battery electric vehicles. Charging at megawatt level will allow trucks to be recharged within the mandatory 45-minuten driver break. The announced Megawatt Charging System (MCS) provides the technical basis. In 2045, approximately 45 TWh - a quarter of the expected electricity demand in the transport sector - could be needed for heavy-duty vehicles.

Previous publications have focused on the economic feasibility of battery electric trucks. Regional demand for charging infrastructure has also been examined. However, it is not fully clear how charging can be integrated into logistics processes. Different charging options - or charging strategies - will affect the ability to use battery electric trucks and the corresponding load curve.

This analysis aims to provide representative load profiles for a future German battery electric truck fleet in 2030 and 2045, given three different charging strategies: (1) As slow as possible (ASAP). The entire time available for a charging process is used to charge the vehicle battery. The strategy is designed to minimize the additional load on the electricity grid. (2) As fast as possible (AFAP). The charging process starts immediately after a trip is completed and ends when the battery is fully charged. The strategy is probably the most challenging for the electricity grid. (3) Combination. Charging at the depot is limited to 44 kW and follows the ASAP strategy. Public charging follows the ASAP strategy. This strategy provides a real-world oriented approach.

Methods

The survey “Kraftfahrzeugverkehr in Deutschland” (KID) contains 2,400 one-day driving profiles of diesel tractor trucks (>12 t) and diesel rigid trucks (>12 t) in Germany. We simulate these profiles as battery electric truck profiles. Each profile contains all trips of the specific vehicle (start time, end time, distance). In addition, it is known whether the breaks between trips were at private or at public locations. We assume that the vehicle starts the first trip of the day fully charged. Starting with the first trip, the day is simulated in 5 minute steps. If the vehicle is parked for at least 30 minutes and if the state of charge (SOC) is below 20 %, the vehicle is recharged. A driving profile is considered feasible, if the SOC is never zero and if the vehicle can be recharged after the last trip until the first trip starts again.

Figure 1 shows an exemplary driving profile for 2030. The vehicle starts driving at 7:00. After six trips and 321 km, the vehicle reaches less than 20% SOC (maximum distance: 350 km) and recharges at a public location. In 45 minutes, 280 km are recharged, which equals the maximum average charging power of 430 kW. After another trip, the vehicle arrives at its depot. Depending on the charging strategy, the vehicle is either charged slowly overnight or fast on arrival. As the vehicle cannot fully charge during the first charging stop and therefore charges at the maximum possible charging power, the ASAP and Combination strategies are identical in this case.

For 2045, we assume a maximum distance of 590 km and a maximum average charging power of 810 kW.

The technically feasible driving profiles are scaled to represent one third of the entire truck fleet in 2030. For 2045, we assume that all vehicles that can be electrified are electrified. Finally, load profiles can be derived.

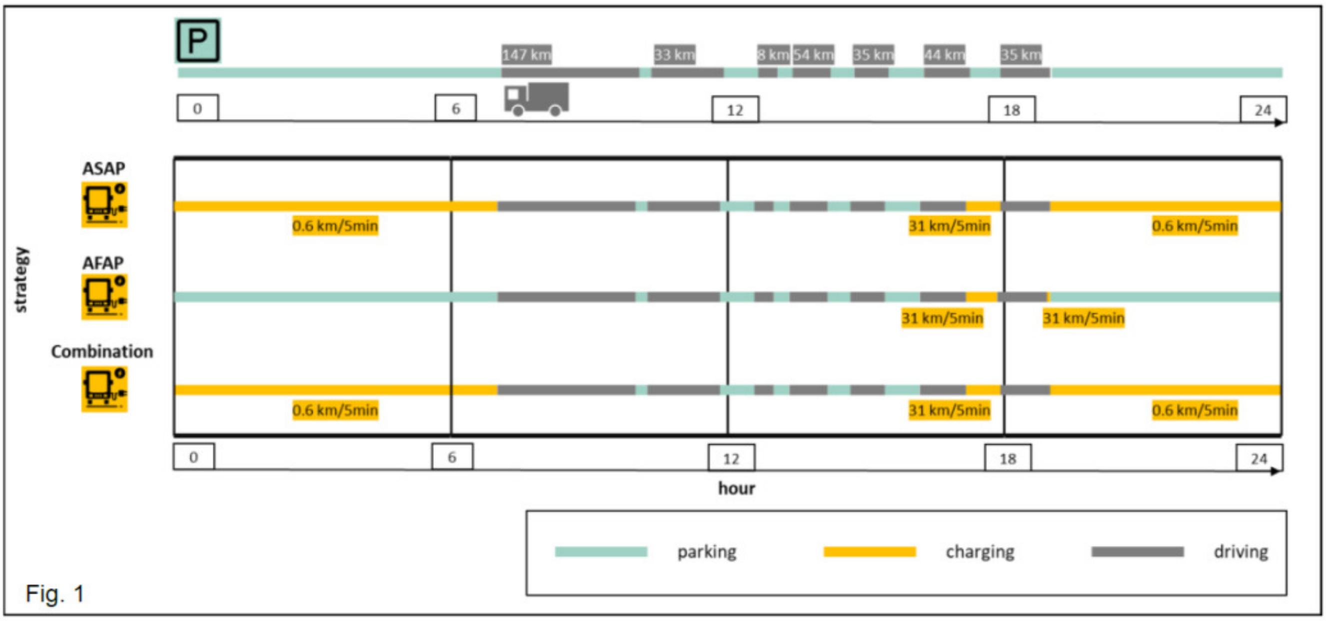

Figure 1

Results

As shown in Figure 2, in 2030 half of the fleet can be electrified with just one (overnight) charging event per day. By 2045, the share increases to almost three quarters of the fleet. However, there are charging profiles that cannot be electrified. While their share is comparatively low in the ASAP and AFAP strategies (14% in 2030, 4% in 2045), almost 40% cannot be electrified in the Combination strategy in 2030 (18% in 2045). This is mainly due to the limited charging power at the depot (max. 44 kW), which prevents the vehicles from being fully charged. Only a minority of vehicles recharge multiple times.

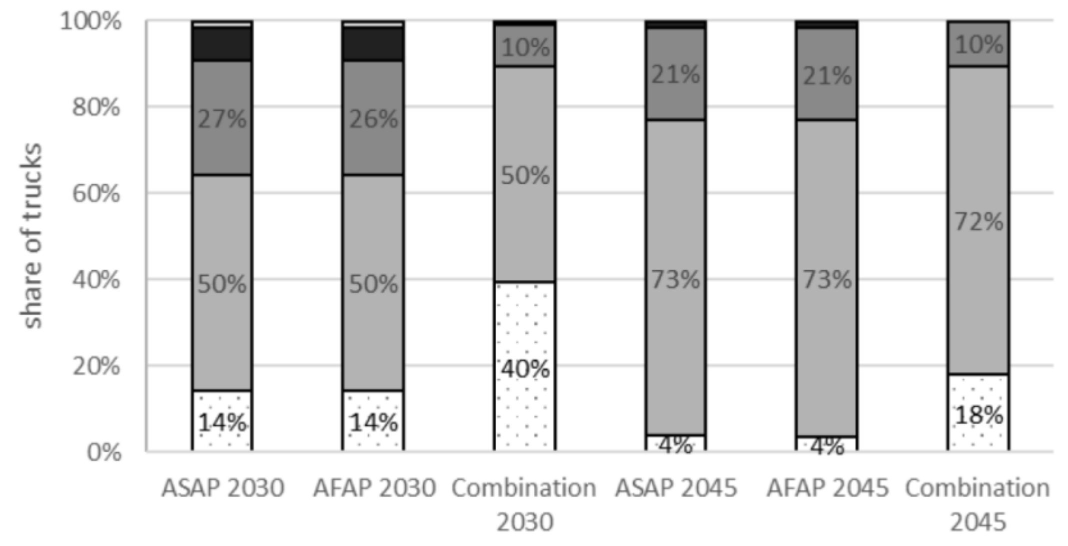

Fig. 2

Figure 2

Figure 3 shows the charging power throughout the day for the defined charging strategies in 2030 and 2045. Obviously, the AFAP strategy leads to substantial peaks in the midday and evening hours. The midday peak is due to vehicles that do intermediate charging, while the evening peak is due to vehicles charging for the next day. At nearly 6 GW in 2030, the peak reaches almost 10 % of today's usual power demand in Germany. In 2045, the peak reaches almost 18 GW, although total demand is expected to grow in all sectors. The ASAP and Combination strategies have a much lower power demand. ASAP is always higher than Combination. In 2030, we assume that one third of the fleet is electrified. In the Combination strategy, it is mainly vehicles with below-average mileage being electrified, resulting in lower energy demand (35 GWh/day vs. 50 GWh/day). In 2045, the share of electrified vehicles and their energy demand in the Combination strategy is lower than in the other strategies (82 % vs. 96 %, 145 GWh/day vs. 100 GWh/day).
Our results show that heavy-duty battery electric trucks will generate a relevant electricity demand and power demand. From an academic view, their energy demand and load profile should be considered in energy system modeling. Policymakers and the industry should create frameworks that enable slow, controlled charging of trucks to avoid peak loads.

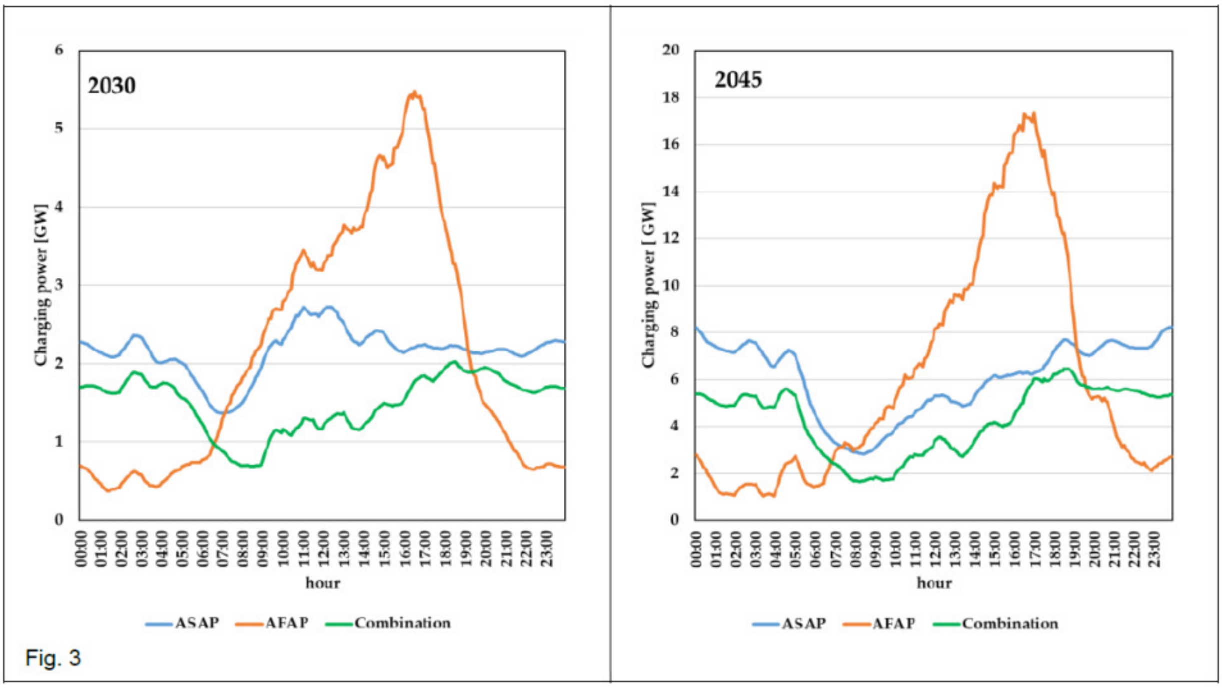
2030
Charging power [GW]
hour
ASAP
AFAP
Combination
2045
Charging power [GW]
Fig. 3

Figure 3

Integrating agent-based electric car simulation in energy system optimization – Potential impact of controlled charging and Vehicle-to-Grid on Germany's future power system

Fabio Frank[1] (Speaker), Till Gnann[2], Daniel Speth[3], Bastian Weißenburger[4], Benjamin Lux[5]

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Keywords: electric vehicles, smart charging, load shifting, vehicle-to-grid, energy system modeling

Motivation

Germany's energy system will have to undergo a fundamental transformation within the next two decades to achieve greenhouse gas neutrality in 2045. The long-term scenarios (www.langfristszenarien.de) created by Fraunhofer ISI, consentec, ifeu, and TU Berlin indicate that Germany's electricity generation will mainly rely on wind turbines and photovoltaic systems. To be able to integrate the intermittent electricity generation, flexibilities in the power system are increasingly important.

The electrification of transport interconnects the previously largely independent sectors of transport and electricity. A growing stock of plug-in electric vehicles (PEVs) can provide an additional flexibility option to the sector-coupled energy system in two ways: One, if charged in a controlled manner, PEVs become flexible power consumers whose charging load can be shifted according to the system needs. Two, if bidirectional charging is realized, PEV batteries can even feed electricity back into the grid (vehicle to grid, V2G) and thus serve as electricity storages.

This study aims at assessing the potential impact of load shifting and V2G on the technologies of Germany's power system in 2030 and 2045. Compared to previous research, PEV fleet projections in line with Germany's current climate policy objectives are considered. The modeling of passenger car charging flexibility within the energy system optimization model Enertile (www.enertile.eu) is updated by integrating the results of the agent-based PEV fleet simulation model ALADIN (www.aladin-model.eu), which is based on several thousand real-world driving profiles.

Methods

The combined models (outlined in Figure 1) are used to analyze the potentials of PEV charging flexibility by comparing controlled charging and V2G scenarios to an uncontrolled charging scenario. The scenarios are based on the T45-Strom scenario from the long-term scenarios. In a ceteris paribus analysis, the shares of PEVs that participate in controlled charging and V2G are varied.

Enertile solves the linear cost minimization problem for supplying electricity, heat, and hydrogen in each hour and region in all simulation years. It simultaneously minimizes fixed and variable costs for expanding and dispatching generation, transmission, and storage infrastructures. The model distinguishes between unmanaged PEV charging, where the load profile is given, and managed charging, where the batteries of all participating PEVs are aggregated as a single battery storage, constrained by given hourly-resolved profiles for energy consumption (driving), maximum (dis)charge power, and minimum and maximum storage content.

The required profiles and the projected PEV market diffusion are generated using the agent-based simulation model framework ALADIN. The market diffusion model simulates the choice of the utility-maximizing drive option for individual car users, Given a fixed driving profile for each simulated car, the fleet's charging behavior is simulated minute by minute, employing two charging strategies. The SOC-minimizing strategy provides that all PEVs charge as late as possible and only the amount of energy that is required at a time, resulting in a profile describing the minimum cumulative energy stored in the batteries. The SOC-maximizing strategy corresponds to uncontrolled charging, i.e., charging as soon and as much as possible. This results in a profile describing the maximum cumulative energy stored in the batteries for each time step as well as an aggregated load profile for uncontrolled charging.

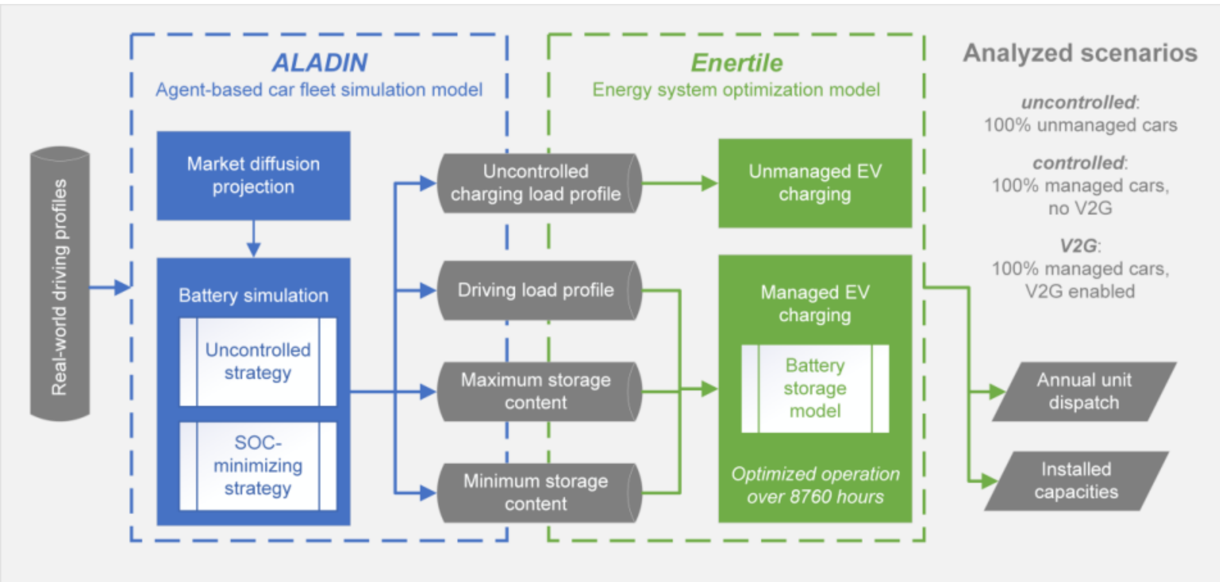

Figure 1: Overview of the model coupling. Only the passenger car-related parts of the models are shown.

Figure 1

Results

The model results show that the implementation of controlled PEV charging impact the electricity generation technologies as well as the flexibility options of the power system. With their demand-side flexibility, electric cars can contribute to the integration of renewable energy and reduce the need to expand capacities during the energy transition in the coming years. Figure 2 shows the difference in installed generation, transmission and storage capacities and Figure 3 shows the difference in annual electricity generation, trading, and system losses for both the controlled and the V2G scenarios compared to the uncontrolled scenario.

In the optimized system, PEV loads are shifted to times of surplus electricity, which results in an annual curtailment reduction of about 60 %. With the implementation of controlled charging, PEV batteries can replace stationary batteries, such that less than half of the utility-scale battery capacities are built until 2045, compared to the uncontrolled scenario. Moreover, the need for peak power generation from gaseous fuels is reduced – natural gas power plants are phased out earlier and 30 % less hydrogen-fired generation capacity will be built until 2045 in the optimized system. In addition, a slightly increased expansion of solar power capacity (+ 5 GW) in the long term is facilitated. Controlled charging reduces the expansion of the cross-border transmission capacities (-12 GW) in the optimized system and therefore decreases trading with neighboring countries in the long term. Whereas it is associated with more system losses, V2G generally reinforces the effects of controlled charging on generation technologies and alternative flexibility options in the power system.

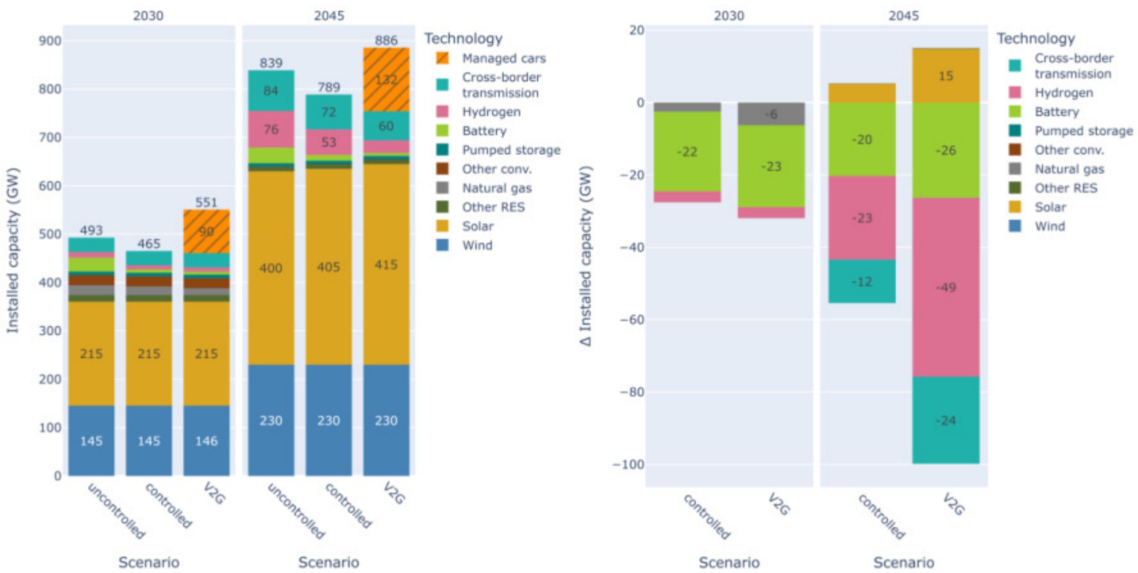

Figure 2: Total installed electricity generation, storage and cross-border transmission capacities in the optimized system (left) and differences in capacity to the uncontrolled scenario (right)

Figure 2

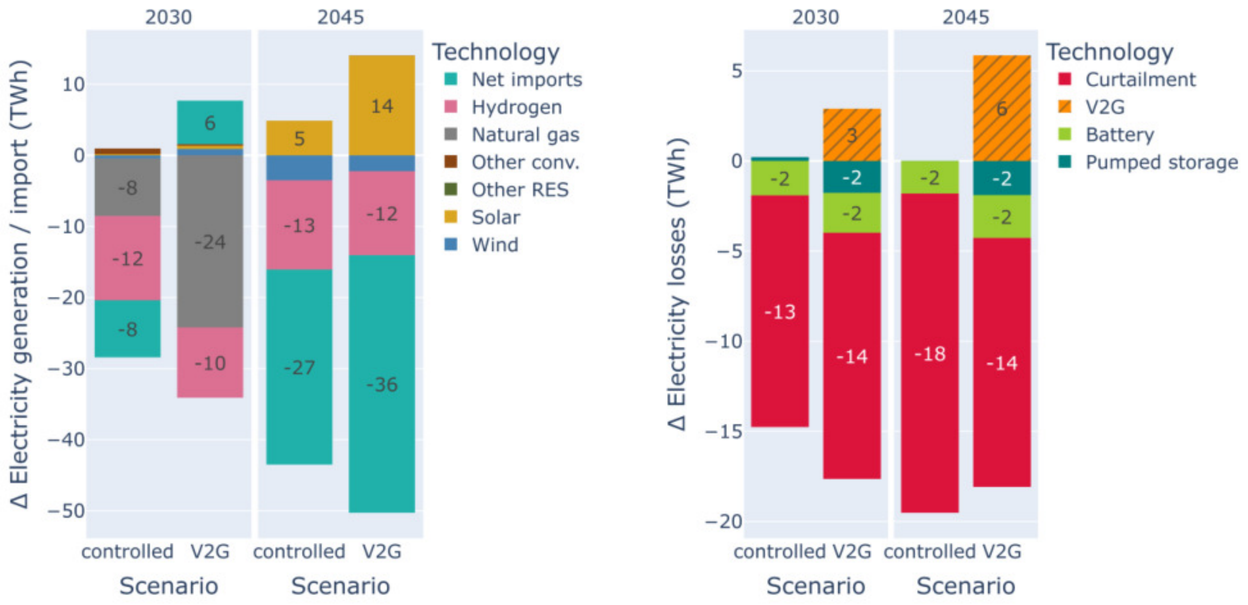

Figure 3: Differences in annual generation (left) and system losses (right) compared to the *uncontrolled* scenario

Figure 3

Modeling synthetic load profiles of future e-truck charging hubs at service stations

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Keywords: charging infrastructure, load profiles, e-trucks, energy system modeling, szenario analysis

Motivation

The European Union has set itself the ambitious target of reducing CO2 emissions in the transport sector by at least 55% by 2030 compared to 1990 levels. In addition to the electrification of private cars, the focus is increasingly on light and heavy commercial vehicles, as these are responsible for around 28% of greenhouse gas emissions in the transport sector [1]. In order for logistics companies to remain profitable, large battery packs within the vehicles with long ranges as well as nationwide charging infrastructure in the megawatt range for short charging times are required. This will have a significant impact on the security of supply, making grid connection capacities, load peaks and simultaneity factors urgent issues for the electrical distribution network on the European highway network [2].

This research work focuses on the modeling of charging infrastructure systems for heavy commercial vehicles (> 12 t gross vehicle weight) for rest areas on the German freeway network. Manufacturers of such vehicles are already forecasting that battery-electric e-trucks will account for around 60 % of total sales by 2030 [3]. In order to minimize the impact of the technology change on transport flows and delivery times, sufficiently large charging hubs at rest stops will be essential. The modeling of synthetic load profiles at the charging points as well as aggregated at nodes and grid connection points plays a central role for a large number of application areas. We therefore address the following research questions in this paper:

- How should a methodology for modeling synthetic load profiles for e-truck charging hubs be designed?
- What charging capacities must charging hubs at service stations be equipped with in order to meet the demand from future traffic volumes depending on the location?
- How much greenhouse gas can electric truck charging hubs save in the future compared to diesel filling stations in the use phase alone?

Methods

The first step is to define market ramp-up scenarios for the reference years 2025, 2035 and 2045 in order to be able to consider the general development of overall traffic, the share of e-trucks and the development of installed battery capacities. In addition, three expansion stages are defined for the charging hubs at service areas, which differ in the number of different types of charging points. Furthermore, the input data for modeling the load profiles at the charging points is formed from the attributes of the arriving trucks. In addition to the arrival time and the preferred charging station type, these also include the battery capacity, the battery status, the charging curve, the charging time and the cumulative amount of energy charged for each truck. The attributes are formed on the basis of currently available, real e-truck models and generated randomly [5]. The calculations are based on hourly traffic data from the Federal Highway Research Institute for specific counting points on the German highway network, which are translated into a 5-minute trigger using an approximated polynomial function [6]. Dynamic data on the battery-electric trucks arriving are derived from the traffic data throughout the day [7].

Therefore, the Monte Carlo simulation methodology is used in this work. The model works in two steps: First, the arriving trucks are assigned to the free charging points in each time step. In the second step, the charging time and the charging status of the truck are queried and a decision is made as to whether the truck is charging, blocking the charging station or leaving the service area. In addition, static charging management is implemented, which ensures that a definable maximum grid connection power is not exceeded, taking power losses into account. The transferred charging power is aggregated across all charging points of the charging hub in each time step to form a synthetic overall load profile and then evaluated for the specific issue.

Results

The choice of the analysis location has a significant influence on the synthetic load profile of the charging hub due to the different traffic volumes. To validate the implemented methodology, various characteristic locations on the German freeway network are therefore analyzed and compared. One of the investigated locations is the "Aachener Land" service area on the A4 highway near the Aachener Kreuz junction with an average traffic volume of 65,312 vehicles per day (2021 count). Figure 1 shows examples of evaluations of the location.

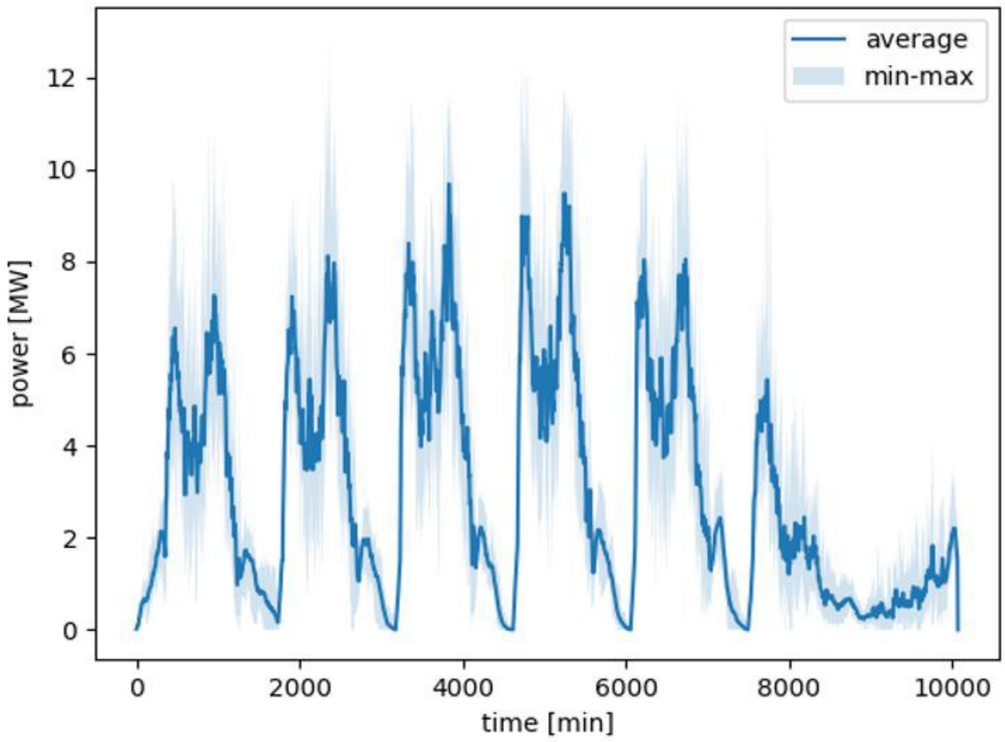
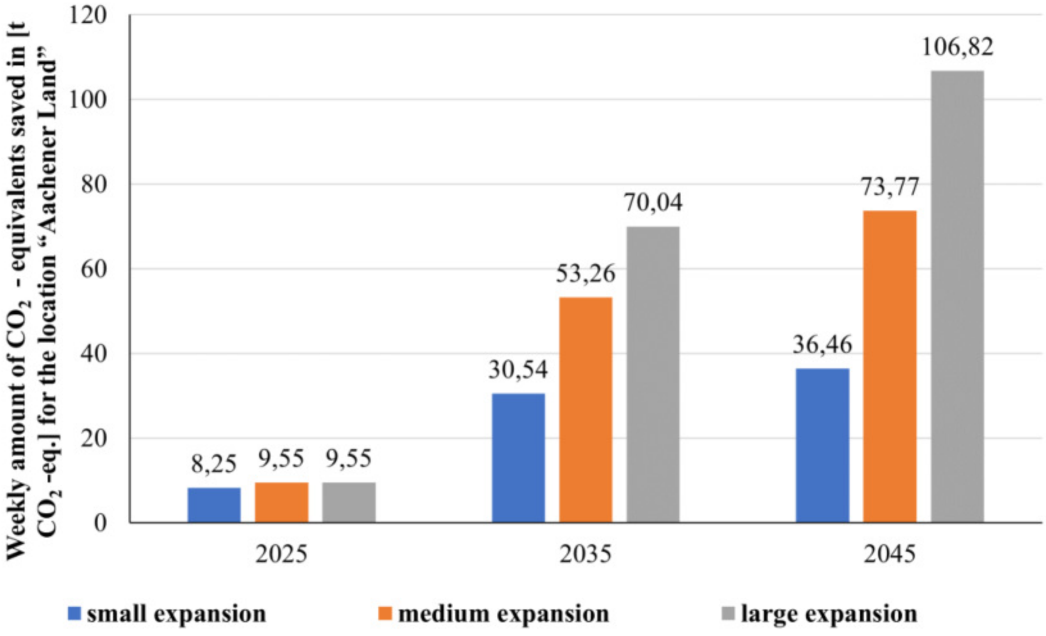


Figure 1

Our preliminary results show that the required aggregated charging capacities differ considerably in the three reference years and react very sensitively to the assumptions from the market ramp-up scenarios. For the reference year 2025, the lowest capacity of 2,727 kW can be found in the small expansion. The maximum capacity does not differ for medium and large-scale expansion and is approx. 21 % higher. The traffic volume is already almost completely covered here with the medium expansion. In the reference year 2045, the maximum charging capacity in the large expansion scenario reaches 12,891 kW, four times the demand from the year 2025.

This methodology offers an efficient procedure for the rapid and reliable estimation of load profiles for charging hubs. Assumptions regarding traffic volume, the probability of charging and the market penetration of e-trucks have the greatest influence on the charging profiles and must be constantly scrutinized in a sensitivity analysis. Furthermore, the largest charging hub expansion defined in this study can only cover 60% of the energy demand at the "Aachener Land" location in 2045. This underlines the need to expand the charging infrastructure for e-trucks in conjunction with a national online charging management system for the highway network.


Weekly amount of CO_2 - equivalents saved in [t CO_2-eq.] for the location "Aachener Land"
120
100
80
60
40
20
0
8,25
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70,04
36,46
73,77
106,82
2025
2035
2045
small expansion
medium expansion
large expansion

Figure 2

Session 9:50 – 10:50
Energy policies, systems and market designs

Room: HSZ/304/Z, hybrid
Chair: Lisa Lorenz

Implications of a potential bidding zone split for the demand allocation in Germany

Lukas Günner, *Aurora Energy Research*

Long term energy policy vs. dynamic public preferences? A review of German energy policy

Jakob Kulawik, *RWTH Aachen*

Paradigm shift in long-term decarbonization scenarios? A review and results of an in-depth analysis of current IPCC data

Björn Steigerwald, *University of Technology Berlin*

Implications of a potential bidding zone split for the demand allocation in Germany

Max Fydrich[1], Claudia Günther[2], Lukas Günner[3] (Speaker)

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Keywords: bidding zone, flexible demand, electrolysers, localised signals

Motivation

With an increasing share of volatile wind and solar generation in Germany's electricity mix, supply-side volatility will inevitably increase, posing a challenge for electricity grids and consumers. In the first quarter of 2023 alone, a quarter of offshore wind generation had to be curtailed due to grid constraints, creating costs for TSOs (and ultimately households) and wasting renewable energy potential.

To realise this potential and in light of increasing renewables capacity, consuming electricity at the right time and in the right place will become more essential to adapt to the ongoing supply-side transformation. In this analysis, we examine whether a bidding zone split in Germany can create incentives to shift demand geographically closer to generation, thereby reducing system costs for both generators and off-takers through means of a numerical modelling analysis. In our study, we focus on two consumer groups, flexible demand technologies, such as electrolysers, and large industrial consumers.

Methods

For our study, we use the European-wide dispatch and capacity optimization model AERES, developed by Aurora Energy Research. Written in Python and GAMS, the model optimizes the long-term capacity expansion for each European electricity market, alongside the hourly dispatch of wholesale and ancillary markets. The model is uniquely granular, exhibiting technical and economical parameters at a plant level. The demand side is modelled based on hourly demand patterns with flexible demand technologies, such as electric vehicles, heat pumps, and electrolysers, being able to endogenously adjust consumption in response to the power price. For the German market, the model is thus well calibrated with the actual current power generation fleet, allowing insightful numerical scenario analysis.

Using this model, we carry out a scenario analysis to analyse how a bidding zone split would automatically create better incentives for system-oriented electricity consumption. For this, we compare our baseline Central scenario to a Bidding Zone split scenario. For this, we assume a division of the German bidding zone into two zones (North and South) according to the configurations proposed by ACER (Agency for the Cooperation of Energy Regulators) and currently under review by the four German TSOs (Transmission System Operators) as part of a bidding zone review. We then mapped German generation capacity and electricity demand to the respective zones and define the existing inner-German transmission lines as the interconnection capacity between the zones. By modelling the dispatch for each zone, we are able to assess the price effects of splitting the German bidding zone. Finally, we test our results for sensitivity to key assumptions to validate their robustness.

Results

Overall, we find mixed results on the impacts of the bidding zone split on electricity consumption behaviour. First, we find that the bidding zone split could indeed help to more efficiently allocate new flexible consumers, namely electrolysers closer to wind generation in the north. A bidding zone split leads to an average price delta between the zones of up to 9 €/MWh in 2030 between North and South. Additionally, the price duration curves (PDC) from the two zones show a stronger divergence during low-price hours than high price hours. The frequency of low-price hours (<60 €/MWh) is 25% higher in the north than in the south allowing flexible demand, such as electrolysers, to benefit significantly from allocating in a northern bidding zone. They also benefit from a higher share of renewables in the power mix, allowing them to draw power from the grid without a PPA, which could reduce their production costs by up to a third.

Second, for the energy-intensive industries, electricity prices would increase by 3% in 2030 if they were located in a southern zone. This would have a limited impact on the operating costs of most sectors. Furthermore, the benefits of lower prices in a northern zone are unlikely to outweigh the costs of relocation, so a bidding zone split would not provide a significant incentive for energy-intensive industries to relocate to a northern zone to take advantage of cheaper electricity.

Long term energy policy vs. dynamic public preferences? A review of German energy policy

Christina Kockel[1], Jakob Kulawik[2] (Speaker), Saskia Spiegelburg[3], Aaron Praktiknjo[4]

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Keywords: -

Motivation

In response to the energy crisis peaking in 2022, many countries enacted policy measures aiming to re-improve security of energy supply and to lower energy prices. Often this came at the expense of environmental compatibility improvements which had been pushed for in recent years. These actions can be considered as a sudden shift in the relative prioritization among the three energy policy goals – security of sup-ply, environmental compatibility and affordability. However, the abrupt political reshuffling during the 2022 energy crisis is only one illustration of such a rapid shift. Historically, abrupt changes in public opinion have already prompted short-term adjustments in energy policy. This work delves into the dynamic interplay between public opinion and energy policy, using Germany as a case study. Specifically, we examine the relationship between changing public preferences on the energy policy reaction regarding three significant events: the phase-out of nuclear energy, the phase-out of coal-fired power and heat generation, and the recent energy crisis in 2022. The objective of our research is to evaluate in which way transient shifts in public preferences can be harmonized in line with an efficient long-term planning of the energy system, and to high-light potential challenges that may emerge in this process.
We ask: To what extent do unforeseen disruptive events and with them changing public opinion impact long-term energy policies?

Methods

To analyze this question, we look at past long-term scenarios from 2006 onward and compare them with the preferences towards the energy policy targets at that time. For the goals of long-term energy policy we review long term studies and laws by the government on coal fired and nuclear power plants. Exemplary for the latter, this includes the lead scenario 2006 of the German government (Nitsch, 2007), the prolongation of nuclear power plants (German Federal Government, 2010), and the nuclear phase-out act (German Federal Government, 2011). To investigate preferences, we review existing surveys regarding the preferences towards the goals of the energy policy target triangle at the time. This includes German public opinion research on the topic within the period of 2006 to 2023. Furthermore, discrete choice experiments which have been conducted for the first time only weeks after the nuclear accident in Fukushima in March 2011 (Praktiknjo, 2013) and have been repeated over the years since then. We have obtained responses from 564, 1,245, and 233 participants in surveys conducted in 2011, 2015, and 2020, respectively. In addition to the mere change in preferences for different power plant technologies which can be observed in public opinion polls, these studies provide a more direct insight into how respondents' preferences for individual dimensions of the energy policy target triangle shift in relation to one another. In a final step, we combine the insights on dynamically changing preferences and actual policy decisions to show how short-term changes in public opinion shape long-term decisions on the design of the energy system.

Results

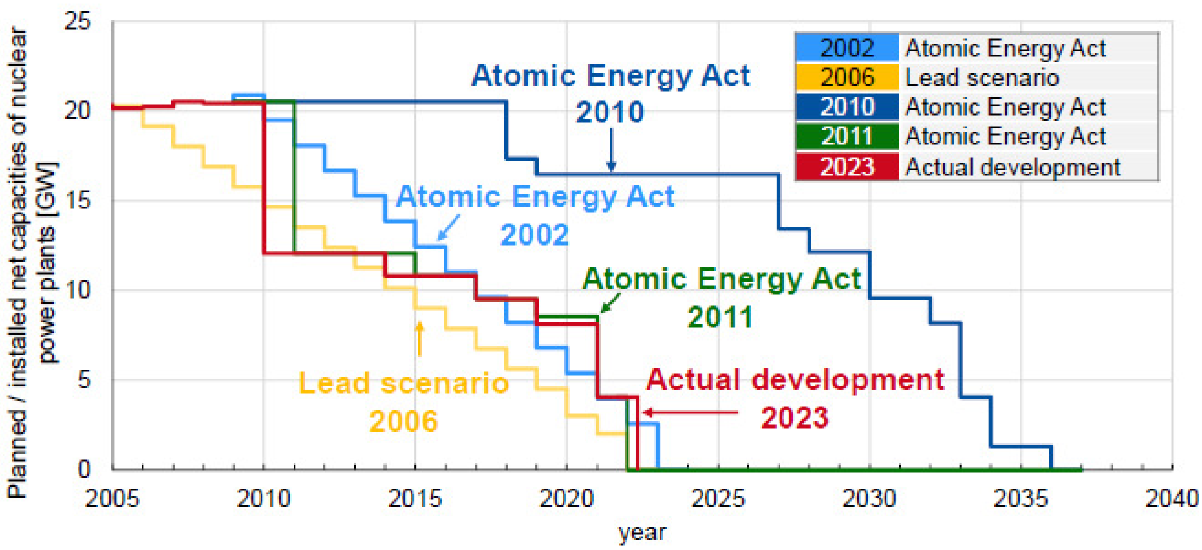

Figure 1: Development of planned and installed capacities of nuclear power plants, (Kockel et. al. 2024)

As an example of the rapid changes in German energy policy, figure 1 shows the planned and installed capacity for nuclear power plants based on the changing policy regulation from 2002 to 2023. Comparing it to the preferences of the German population shortly after the nuclear accident in Fukushima in 2011, displayed in figure 2, this highlights the influence of public preferences on long term energy policy clearly. The strong preference for phasing out nuclear power is accompanied by a sharp reduction in future planned nuclear power plants even though most nuclear power plants were just prolongated in 2010. Besides the nuclear accident in Fukushima, two further events have been identified as pivotal moments which led to sudden changes in the short term on German energy policy measures which were originally planned for the long term.

First, the prominent emergence of environmental movements around 2019, and second, the global energy crisis peaking in 2022.

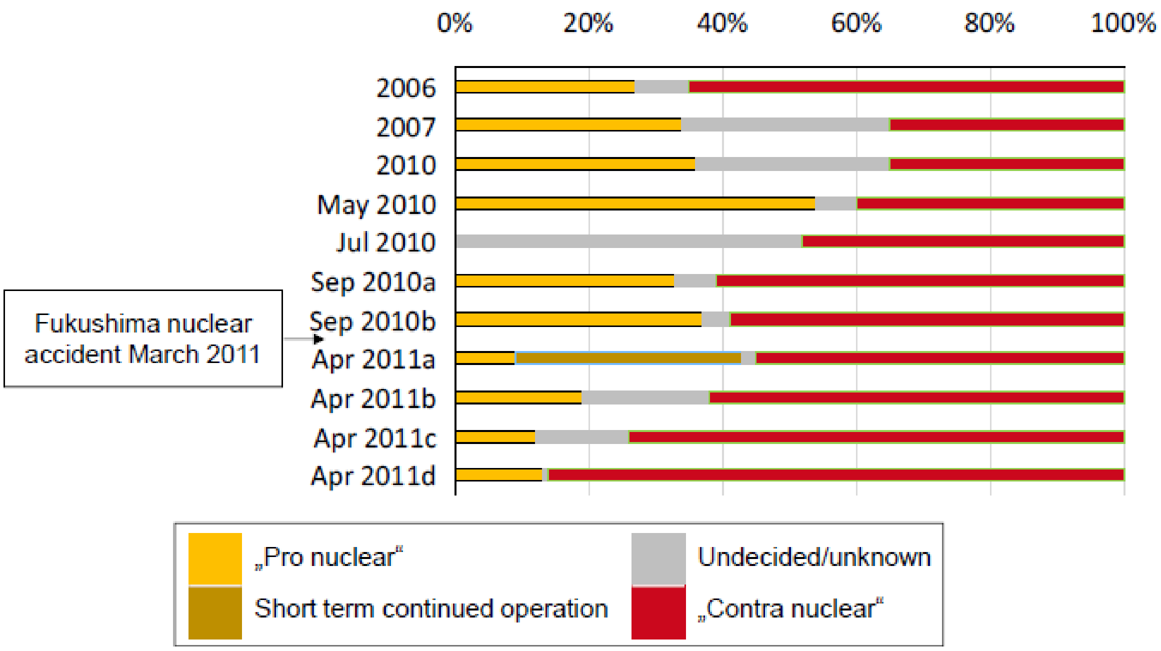

Figure 2: Preferences of the German population shortly after the nuclear accident in Fukushima according to public opinion research (based on Kockel et. al. 2024).

Concluding the results of our research, we take a retrospective look at the preferences of the German population with regard to the energy policy target triangle and the scenarios for energy policy developed from it. The aim of our analysis is to shed light on the weighing of energy policy target preferences and how German energy policy de-pends on the view of the electorate. This is relevant because energy policy requires measures and regulations that are durable, especially due to the long-term nature of the energy system and its components. Knowing how people form preferences can therefore help to make both short- and long-term policies more effective. At the same time, it can serve as a basis for implementing measures based on the preferences of the population that benefit the public but also lead to a sustainable transformation to a fossil-free power system.

Paradigm shift in long-term decarbonization scenarios? A review and results of an in-depth analysis of current IPCC data

Björn Steigerwald[1] (Speaker), Jens Weibezahn[2], Christian Breyer[3], Christian von Hirschhausen[4]

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Keywords: Energy, Dynamics, Nuclear, Scenarios, Future Energy System

Motivation

A steep cost decline for the generation of renewable energy, combined with recent advancements in storage and flexible technologies mainly driven by batteries and renewables-based hydrogen, drive a paradigm shift in energy systems worldwide. Consequently, renewable energy today dominates investments in electricity generation systems (Ram et al. 2022). Next to this paradigm shift towards renewable energies, we however see an increasingly uncertain dynamic in the developments of the future energy system. For example, the recent Covid pandemic and the Ukraine war, underline the importance of long-term energy scenarios in providing guidance to industry and policymakers concerning potential future decarbonization pathways (Bistline et al. 2023; Intergovernmental Panel On Climate Change (IPCC) 2023). Since the beginning of long-term energy planning, nuclear power has played a crucial role due to expected technical progress and the difference in real cost developments (Steigerwald et al. 2023). However, a recent paper from the Integrated Assessment Modelling (IAM) community and scenarios with updated cost assumptions of renewables, in particular for solar PV and energy system integration costs, point in the opposite direction. In fact, there seems to be evidence that due to high costs, nuclear power could be phased out in the coming decades, which we explore in more detail in this Paper (Luderer et al. 2021; Löffler et al. 2017; Teske 2018; Jacobsen 2020).

Methods

We build a sophisticated dataset of recent IPCC reports (Huppmann, Daniel et.al. 2019; Byers, Edward et.al. 2022) to compare the latest developments in electricity generation for the 2020 - 2100 timeframe. After some quality assurance measures in the dataset, we start with a first general consideration of integrated assessment models and their distribution and their change between the two datasets. We then deepen this by introducing a location parameter m, the slope parameter of a mathematical regression analysis, in order to be able to recognize an initial trend in the distribution over time and potentially. Splitting the time period of our regression analysis provides us with a further opportunity to refine and verify the previous results. Further sophisticated mathematical and statistical methods then help to investigate the current developments in the current IPCC datasets and to identify further paradoxical assumptions of some scenarios of the future energy system and their possible influences. We observed a change in the distribution of the integrated assessment models between the Huppmann (2019) and Edwards (2022) datasets, where the main scenario focus shifts from the AIM/CGE 2.0 model to the Messageix framework.

Results

We observed as a preliminary result a change in the distribution of the integrated assessment models between the Huppmann (2019) and Edwards (2022) datasets, where the main scenario focus shifts from the AIM/CGE 2.0 model to the Messageix framework. The total number of scenarios for integrated decarbonization assessment models increased, while the number of scenarios with an increasing share of nuclear decreased (Figure 1). The currently very sparse cost assumptions in both datasets and their partial correction seem to have influenced this. A continuous need for a critical assessment and update of long-term scenarios to understand this paradigm shift, both concerning cost assumptions and other variables including, for example, emission intensity or land use. The modeling efforts for a largely decarbonized energy system have only just begun!

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

Room: HSZ/004, hybrid
Chair: Andreas Büttner

Modelling to generate alternatives for decarbonising the energy supply of a large university campus

Katharina Esser, *Ruhr-University Bochum*

Drivers of flexibility in a renewable energy system – correlation analysis with a sector-coupled energy system model

Patrick Jürgens, *Fraunhofer ISE*

Welfare redistribution through flexibility - Who pays?

Nils Namockel, *University of Cologne (EWI)*

Modelling to generate alternatives for decarbonising the energy supply of a large university campus

Katharina Esser[1] (Speaker), Jonas Finke[2], Valentin Bertsch[3], Andreas Löschel[4]

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Keywords: Decarbonisation, Modelling to Generate Alternatives, Energy System Model, Higher Educational Institutions, Decision-making

Motivation

Universities should play a leading role in the transition from fossil fuels towards renewable energy sources and in promoting the principles of sustainability. Energy system models are a key tool for dealing with the challenges of this transition by optimising or simulating different scenarios for future energy systems to help decision-makers and planners evaluate the impact of system design or operation decisions, policies and macroeconomic developments. However, these models inevitably simplify the complexities of real-world problems, often by reduction to pure cost optimisations. They face great uncertainty with one main driver being the complex real-world dynamics that cannot be captured by a mathematical model yet drive the acceptance of its solution. They are further specified as values, preferences, or social norms of decision-makers or stakeholders that are neither easily quantifiable nor measurable. Modelling to generate alternatives (MGA) is a technique to cover a wide range of uncertainties, which may be unknown at the time of modelling, without the need to define and formulate them in detail. By generating alternative solutions besides the cost-optimum in the near-optimal space, the results show different ways of almost achieving the optimum, e.g. different technology mixes which are almost cost-optimal. They may contain solutions that are preferred by different interest groups among decision-makers or stakeholders. Although MGA has been applied to a wide range of energy planning problems, applications to sector-coupled small-scale energy systems with a central decision-maker are rare. Therefore, we use Ruhr-University Bochum (RUB), one of the largest universities in Germany, as an example. With an annual energy demand of about 210GWh, decarbonising RUB's energy supply plays a key role in the promotion of sustainability on the campus, in the Ruhr area and beyond.

Methods

We use Backbone, a highly adaptive mixed-integer linear optimisation framework for energy systems modelling implemented in general algebraic modelling system (GAMS), to develop a detailed energy system model of Ruhr-University Bochum with comprehensive real data that couples heating, cooling and electricity. To adapt the energy system model to the years 2030 and 2045, it is modified in terms of available technologies such as renewable energy sources, technology-specific developments like investment costs, energy demands, CO2 targets as well as fuel and CO2 prices. We combine the energy model of the RUB with a highly flexible implementation of MGA to explore diverse, near-cost-optimal decarbonisation paths for the energy supply. The problem is solved multiple times for different weighting methods of a selected decision variable, different upper bounds, which allow a relative deviation from the optimal total system costs, and the two different target years. In total, we obtain 400 near-cost-optimal solutions which we analyse in the following ways to support decision-making concerning a decarbonised future energy supply at RUB: Firstly, we identify must-have, must-avoid and real choice technologies for the target year 2045. Must-haves are technologies that are deployed in every alternative without exception, but potentially with varying utilisation, whereas must-avoids are technologies that are not part of any alternative. Secondly, we explore the sensitivity of the solutions regarding their relative deviation from the optimal total system costs as well as path dependencies for 2030 and 2045. Finally, we analyse selected solutions, a set of maximally different alternatives, in more detail. Beyond the scientific objectives, the findings are fed into the university-internal decision-making process to promote sustainability at RUB. Our approach and general insights can be transferred to other university campuses to encourage sustainability action and climate leadership.

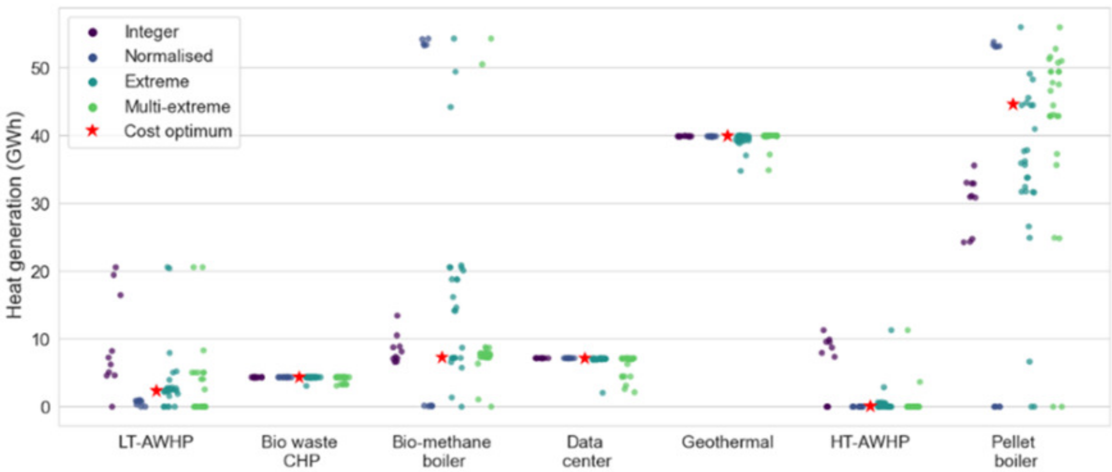

Figure 1: Heat generation per technology for all alternatives in the base scenario, i.e. the year 2045 and 1 % slack, for all four weighting methods. Each dot per technology group represents one alternative and the red star indicates the cost-minimal solution.

Figure 1

Results

We find that the cost-optimum is extremely flat for full decarbonisation at RUB in the target year 2045. At 1% extra costs, the geothermal power plant and at least one of the type of bio-based boilers must, while the low- and high-temperature air-water heat pumps (AWHP) and the second type of bio-based boilers can play a significant role in RUB's heat supply (see Figure 1). The bio waste combined heat and power (CHP) plant and data centre are must-haves but can satisfy only below 10% of the annual demand (see Figure 1). Due to limited land availability for alternatives such as photovoltaics (PV) and wind, about 90% of the electricity has to be procured, regardless of allowed costs. Cooling is 100% electricity-based, but there is a real choice between cooling-AWHPs with higher investment costs and efficiency and existing compression refrigeration machines.

Second, for higher extra costs, the room for decision-making between real choices increases further. At 5% extra costs, there are no must-have technologies and at 10% either of the two boiler types can cover the full heat demand, while low- and high-temperature AWHPs can provide up to 47% and 86%, respectively (see Figure 2). Therefore, each heating technology can be avoided within this cost range if desired by decision-makers or compelled by external circumstances.

Third, considering near-cost-optimal alternatives can harmonise the system designs between the years 2030 and 2045, while the least-cost solutions indicate inconsistent or opposing operation and investment decision, in particular regarding the deep geothermal plant, the existing natural gas CHP and low-temperature AWHPs (see Figure 2).

Fourth, the large scope for decision-making can be used to satisfy unmodelled interests beyond costs, CO2 emissions and meeting demand. For instance, risk diversification, flagship projects, or lower realisation efforts can be pursued.

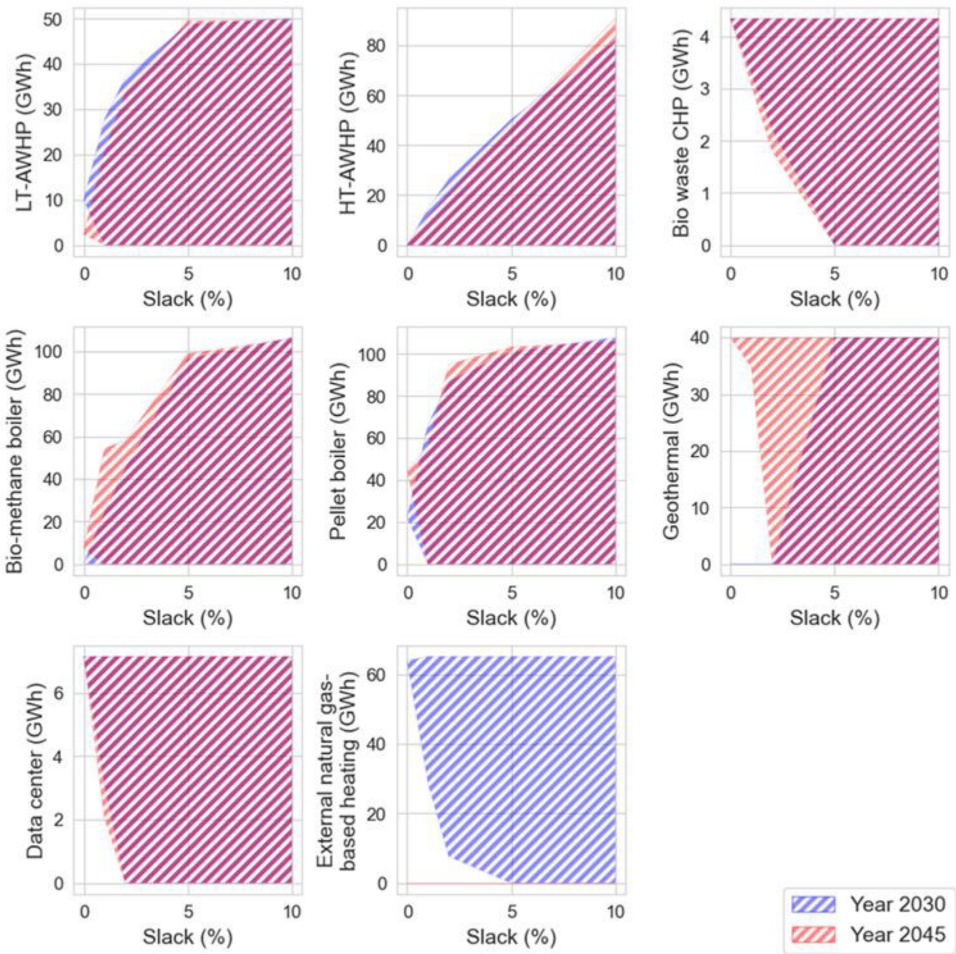

Figure 2: Slack sensitivity of all heating generators in 2030 and 2045 up to 10 % slack

Figure 2

Drivers of flexibility in a renewable energy system – correlation analysis with a sector-coupled energy system model

Patrick Jürgens[1] (Speaker), Nourelden Gaafar[2], Jael Sepúlveda Schweiger[3], Christoph Kost[4]

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Keywords: energy system modelling, sector coupling, energy transition, flexibility

Motivation

Germany is committed to reducing GHG emissions by at least 65 % by 2030 compared to 1990 levels, and to achieving net-zero emissions by 2045. This implies an energy transition towards a sustainable, sector-coupled, renewable energy system.

In this context, a significant share of electricity will have to be provided by variable renewable energy sources, wind and PV, which cannot adapt their output to demand. To meet this challenge, flexible technologies are essential to balance the residual load, defined here as the difference between non-flexible demand and non-dispatchable, non-flexible generation. Flexible technologies can control their electricity consumption or production to balance the residual load.

However, there are many challenges to implementing flexible technologies, including cost variability depending on the energy source and regional market conditions. These technologies provide different forms of energy (electrical, thermal, chemical, etc.) with varying levels of efficiency, affecting system performance and economics. Ranging from short-term to seasonal solutions, flexible technologies differ in the length of time they can provide energy. They also range in maturity from established options such as pumped storage to emerging innovations. Expanding the infrastructure for flexible solutions entails additional costs (IEA 2018, AGORA 2022, Impram 2020, Jankowska 2022).

These challenges underline the importance of thorough planning, comprehensive analysis and in-depth research to ensure a secure and sustainable energy supply, consistent with climate goals, at the lowest possible cost. In this context, the primary research question addressed in this paper is: "How can flexibility be provided along the net-zero transition towards a sector-coupled renewable energy system?" The focus of this conference presentation will be on the secondary question: "What are the drivers of different flexibility options in a renewable energy system?

Methods

The energy system model REMod

The energy system model "REMod" is used to model transformation paths of the German energy system (Henning and Palzer 2014; Palzer and Henning 2014; Palzer 2016; Sterchele 2019). REMod uses a simulation-based optimization. The operation of the energy system is simulated with a full hourly resolution based on an operational sequence, while the accumulated costs (CAPEX and OPEX) of the transformation path are optimized using the optimization algorithm CMA-ES (Hansen 2016). The focus of REMod is on 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. For investigating flexibilities in a net-zero energy system, an updated version of the scenario "Technologiemix" published in Luderer, Kost, and Sörgel (2021) is used. A full description of the model is provided by Palzer (2016) and Sterchele (2019).

Time series analysis

To investigate how flexibility is provided in a net zero energy system, hourly time series of the modelled operation are analysed. The data is analysed both at the raw hourly time resolution and aggregated to a monthly scale. Different technologies are grouped together to investigate the proportion of flexibility these technologies provide to the system.

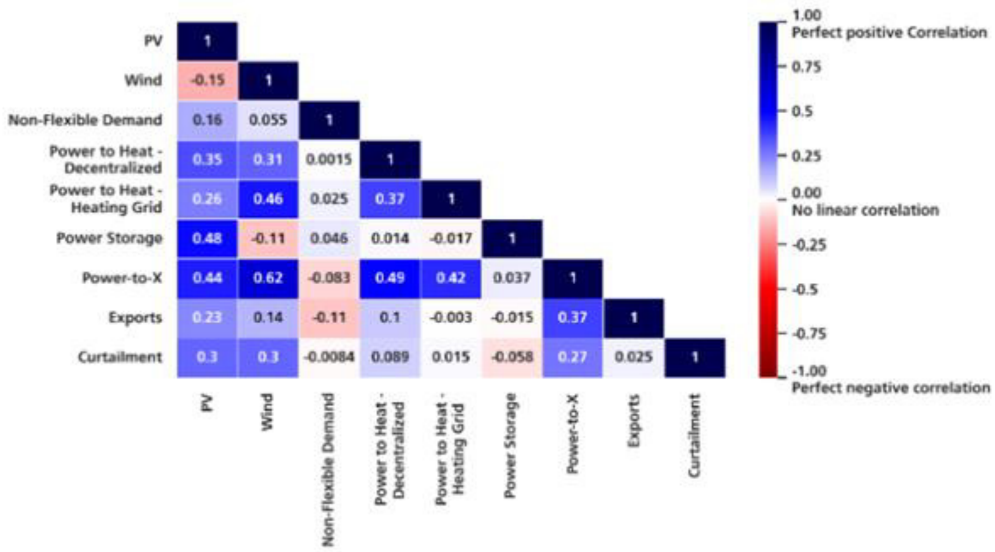
A correlation analysis is used to examine the relationships between the use of flexible technologies and the hypothesised primary drivers of flexible operations. It also examines the inter-correlations between different flexible technologies. The aim is to understand the factors that influence different flexible operations.

To quantify the effect size either Pearson correlation coefficient (r) or Spearman correlation coefficient (ρ) is applied according to the following the common convention:

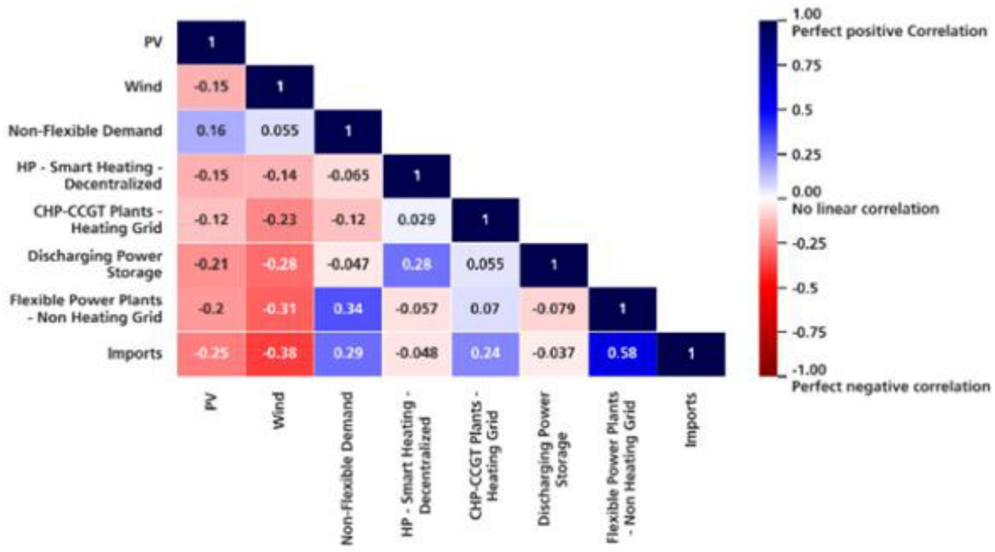
- No correlations: $0 \leq |r| < 0.1$
- Weak correlations: $0.1 \leq |r| < 0.3$
- Moderate correlations: $0.3 \leq |r| < 0.5$
- Strong correlations: $0.5 \leq |r| \leq 1$

Results

The challenge in a renewable energy system lies both in flexibly utilizing "surplus" electricity and meeting end-use sectors' demand. Flexible sector-coupling technologies play a major role, particularly in negative residual load cases, where power-to-X and power-to-heat technologies exhibit the highest contributions. In positive residual load cases, flexible CCGT and CH_4-GT plants, alongside electricity imports, predominate during winter. In summer, discharging power storage represents the highest flexibility. The backup CH_4-GT takes priority during short power deficiency periods. The correlation analysis shows that during negative residual load, production from wind and PV is the main driver for flexible operations, showing positive correlation with all flexible technologies. In contrast, non-flexible demand exhibits no correlations. Power storage technologies exhibit a significant positive correlation with PV due to their short-term storage capability with high efficiency in short-term operations. In contrast, power-to-X technologies exhibit a strong positive correlation with wind, attributed to their long-term storage capability and the ability to consume excess electricity over long periods. During positive residual load, all flexible technologies display negative correlations with wind and PV, as higher production from wind and PV reduces the likelihood of electricity shortage. Flexible CCGT and CH4-GT plants, as well as imports, exhibit a notable positive correlation with non-flexible demand. This indicates that their operation is also driven by non-flexible demand. Inter-correlations between flexible technologies are observed in the strong positive correlation between power-to-X and power-to-heat technologies, driven by their ability to run on long-term, and between imports and CCGT and CH4-GT flexible power plants, driven by their shared operational motivation of covering non-flexible demand, particularly, during low PV and wind generation.



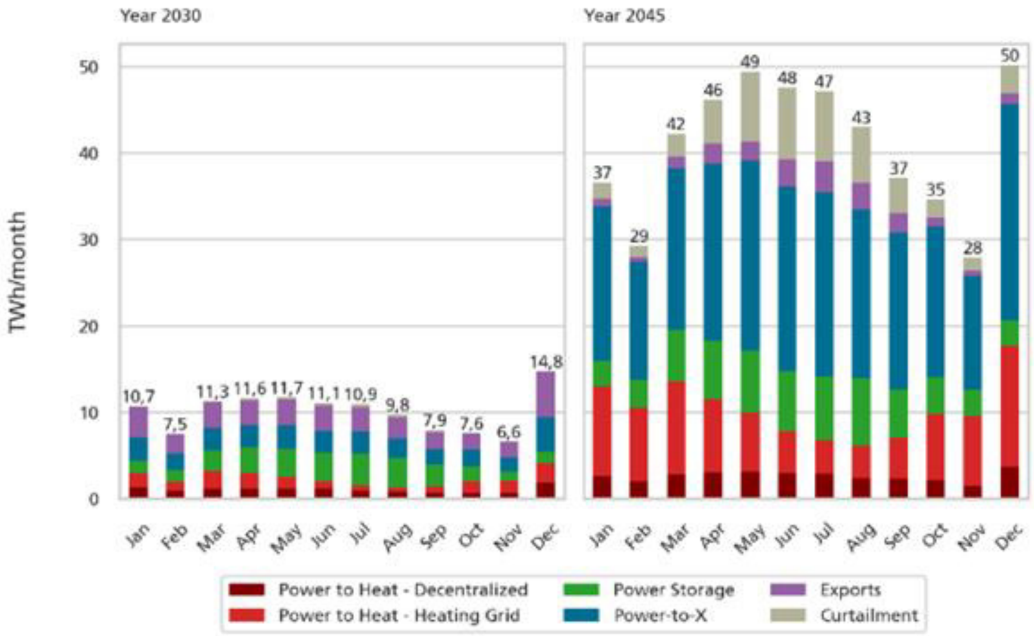
(a) Excess electricity cases.



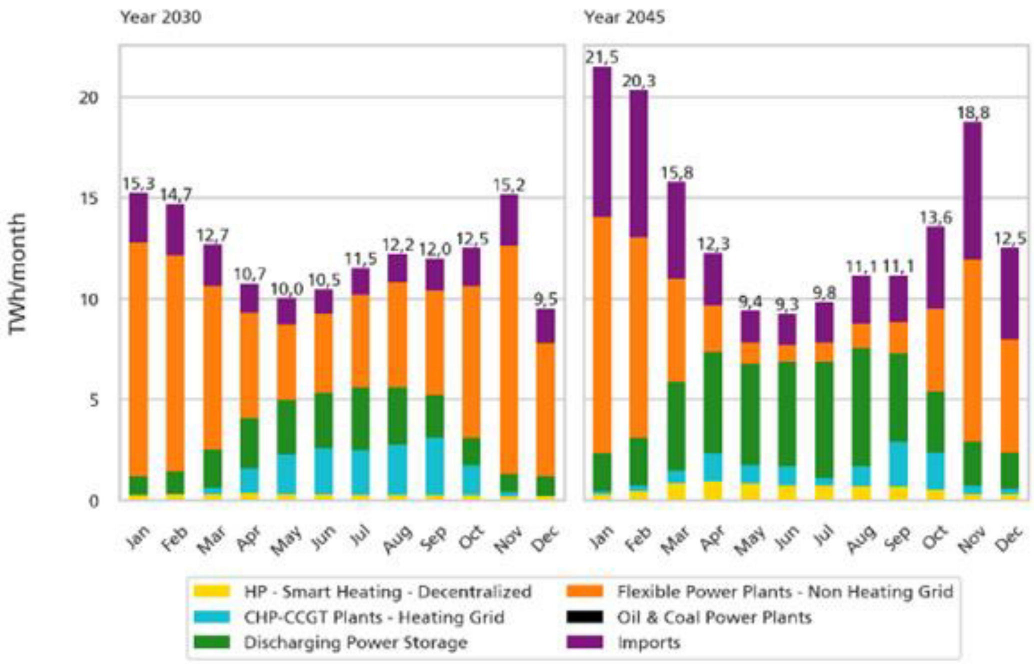
(b) Shortage of electricity cases.

Fig. 13: Hourly Pearson linear correlation matrices for excess electricity (a) and shortage of electricity (b) cases in 2045.

Figure 1



(a) Flexible usage groups in negative RL cases.



(b) Flexible usage groups in positive RL cases.

Fig. 7: Mean-based Monthly contributions of flexible usage groups in negative RL (a), and positive RL (b) cases in 2030 and 2045.

Figure 1

Welfare redistribution through flexibility - Who pays?

Polina Emelianova[1], Nils Namockel[2] (Speaker)

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Keywords: Flexibility, Welfare effects, Energy System Modeling, Energy Transition, End-use Sectors

Motivation

To facilitate the shift to a low-carbon economy, Germany has established technology-specific capacity targets within its national medium-term strategies. These strategies encompass not only renewable energy objectives, but also specific targets related to investments in electrically driven end-use applications such as electric vehicles and heat pumps. Electrification of end-use sectors leads to growing integration of new decentralized suppliers and consumers into the existing power system. The ongoing digitalization opens promising prospects for increasing demand flexibility by temporal shifting of electricity consumption.

If end consumers face dynamic electricity prices, price fluctuations will strongly impact a wide range of new actors in the building and transport sectors, next to the ones in the energy sector. In contrast to renewables, the technologies in the end-use sectors are not homogeneous but comprise non-homogeneous groups with distinctive characteristics. The diverse structure of demand means that the effect of electricity price fluctuations may differ across different consumers. From the actors' perspective, the specific consumer and producer rents are likely to change as flexibility is applied.

The current literature primarily focuses on examining the system impacts of flexibility deployment. However, it lacks the perspective of differentiated end consumers who are assumed to directly interact with the energy system and provide flexibility. This paper aims to fill this gap by addressing the following research questions:

- What is the impact of different degrees of flexibility deployment by end-consumers on electricity prices and well as on producer and consumer rents?
- What are welfare effects of additional flexibility on different consumer groups in the building and transport sector?

Methods

This paper aims to assess system level impacts including electricity price formation and technology-specific welfare effects driven by different degrees of flexibility deployment by end-user applications such as electric vehicles and heat pumps equipped with thermal storage. To analyze the economic consequences of flexibility, especially for the new market participants in the transport and buildings sectors, we enhance the existing energy system model DIMENSION by enabling a high-resolution dispatch for a range of end-consumer groups and flexible technologies. Introducing a high granularity of end-use sectors enables a thorough analysis of the interaction of decentralized flexible assets such as electric vehicles (including vehicle-to-x) and heat pumps combined with thermal storage within the energy system.

Heterogeneity of the buildings sector is ensured by modeling different building types with differentiated heat pump technologies and buildings inertia. For the transport sector we use data from the German Mobility Panel (MOP) to generate about 300,000 mobility profiles, including information on parking location, electricity demand and settlement type. By applying a k-medoids clustering we define heterogeneous mobility cluster with differentiated flexibility potentials.

We apply a case study for Germany that reflects currently set technology-specific goals for the year 2030. We vary the degree of flexibility in the road transport and buildings sectors and combine them to a set of six use cases (s. Figure 1). For the road transport we differentiate between three cases with no flexibility, demand shifting and vehicle-to-x. For the building sector we define a use case with only buildings inertia as potential flexibility and one with additional thermal storages. Based on the described case study we quantify the changes in average and total electricity costs for different building types and mobility clusters depending on the degree of flexibility provision.

Use Cases for end-use sectors		Heating sector	
		inflexible (only with buildings' inertia)	flexible (with additional heat storage)
Transport sector	inflexible	M0/H0	M0/H1
	flexible (DSM)	M1/H0	M1/H1
	flexible + V2X	M2/H0	M2/H1

Figure 1: Scenario definition

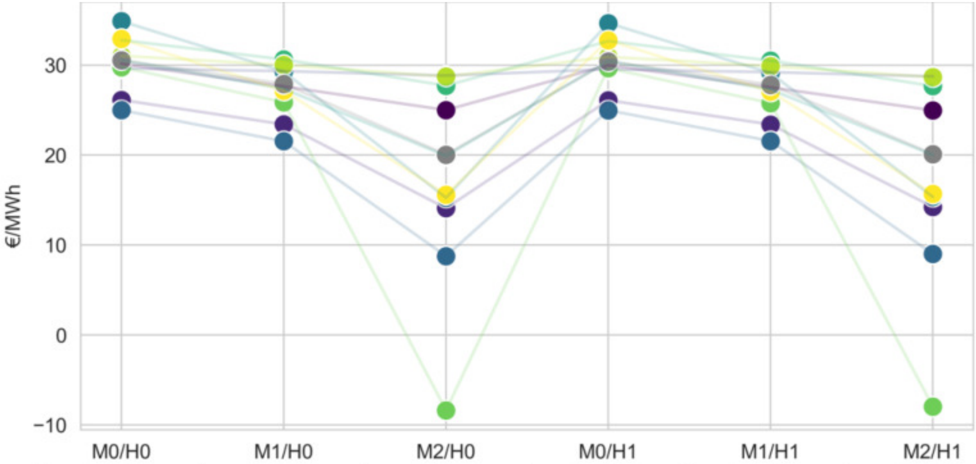
Results

The modelling results show that while additional flexibility by electric vehicles and heat pumps has no significant effect on average electricity prices, it reduces price volatility and drives down peak prices.

For almost all electricity producers (apart from PV systems) revenues decrease with increasing degree of flexibility from the end-use sectors (s. Figure 2 showing the revenues and costs for producer and consumer groups respectively across the use cases, measured in billion euros). On the other hand, for electricity consumers, the adoption of greater end-use flexibility often leads to reduced costs of electricity procurement. However, this trend does not extend to electrolyzers and batteries, which experience decreasing rents due to rising flexibility of the end-use sectors. Overall, the modeling outcomes suggest a noticeable shift in welfare from producers to consumers that can be attributed to the enhanced system flexibility.

Figure 2: Revenues and costs for producer and consumer groups respectively [billion EUR]

Our analysis of various mobility clusters highlights that the owners of electric vehicles can reap benefits from shifting their demand, experiencing average electricity cost reductions ranging between 1 % and 18 % (s. Figure 3 depicting the variation of average electricity costs for different mobility clusters across the use cases). However, the advantages are markedly greater when employing bidirectional charging, with average potential cost savings reaching up to 34 %. Moreover, while the flexibility of electric vehicles considerably lowers the electricity expenses for heat pump operation, the impact of increased heat pump flexibility achieved through enhanced thermal storage on reducing charging costs for electric vehicles is relatively minor. The potential for savings through demand shifting and enhanced flexibility within the building sector is less significant compared to the road transport sector, with maximum total savings of up to 6.4 %.



Mobility Cluster	M0/H0	M1/H0	M2/H0	M0/H1	M1/H1	M2/H1
MC1	30.15	27.63	25.0	29.99	27.52	24.97
MC2	26.13	23.41	14.09	26.09	23.4	14.23
MC3	29.64	29.33	28.83	29.54	29.21	28.75
MC4	24.98	21.54	8.76	24.97	21.56	9.01
MC5	34.88	29.28	15.25	34.67	29.12	15.35
MC6	30.56	27.37	19.91	30.45	27.28	20.01
MC7	32.78	30.63	27.71	32.67	30.49	27.67
MC8	29.77	25.86	-8.37	29.66	25.78	-7.96
MC9	31.03	30.01	28.73	30.92	29.89	28.66
MC10	32.91	27.16	15.58	32.76	27.06	15.7
All	30.53	27.91	20.05	30.41	27.81	20.11

Figure 3: Variation in average electricity costs across mobility clusters

Session 11:15 – 12:15
Hydrogen & natural gas II

Room: HSZ/405/H, hybrid
Chair: Philipp Hauser

Import costs of green hydrogen via ships for Germany

David Franzmann, *Forschungszentrum Jülich*

A fundamental outlook on European gas fundamentals and price for 2024 / 2025

Andreas Schröder, *ICIS*

Low-carbon hydrogen imports to Europe: Case studies and transformation pathways for ramping up green and blue hydrogen

Nima Farhang-Damghani, *FAU Erlangen-Nürnberg*

Import costs of green hydrogen via ships for Germany

David Franzmann[1] (Speaker), Heidi Heinrichs[2], Jochen Linßen[3], Detlef Stolten[4]

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Keywords: green hydrogen, import costs, ammonia, liquid hydrogen, LOHC, maritime transport

Motivation

To transform Germany's energy system to greenhouse gas neutrality, a change in energy supply is needed. While electrification supplied by renewable energy sources will play an important role, it is expected that Germany will also need large amounts of hydrogen. In scenarios, the hydrogen demand ranges from 215 TWh [1] to 458 TWh [2] in 2050 for sectors which cannot be electrified and for supplying the energy system during lulls (e.g. "kalte Dunkelflaute"). Germany is expected to be able to produce between 28 TWh [1] and 201 TWh [3] of green hydrogen, leading to a need of hydrogen imports between 37% [3] and 87% [2] in 2045. Yet, the import costs, quantities, and carriers for importing renewable energy are uncertain.

One promising option is importing renewable energy carriers like ammonia, liquid hydrogen, or liquid organic hydrogen carriers via shipping from countries with low electricity costs from renewable energy technologies [4]. Recent studies analyzed global transportation of hydrogen carriers but are mostly focusing on single countries and carriers [5,6]. For Germany, Brändle et al. [7] calculates the import cost via shipping from several countries but only for liquid hydrogen. Hampp et al. [8] consider several types of commodities, but only for seven selected countries.

Therefore, a more comprehensive analysis of import costs of different greenhouse gas neutral hydrogen-based energy carriers for Germany is needed.

[1] G. Luderer et al.: Deutschland auf dem Weg zur Klimaneutralität 2045 - Szenarien und Pfade im Modellvergleich, Ariadne-Report, 2021

[2] Deutsche Energie-Agentur: Leitstudie Aufbruch Klimaneutralität, 2021.

[3] J. Brandes et al.: Wege zu einem klimaneutralen Energiesystem - Die deutsche Energiewende im Kontext gesellschaftlicher Verhaltensweisen, Fraunhofer-ISE, 2021

[4] doi.org/10.1016/j.ijhydene.2022.05.266

[5] doi.org/10.1016/j.ijhydene.2018.12.156

[6] doi.org/10.1016/j.ijhydene.2020.09.017
[7] j.apenergy.2021.117481
[8] journal.pone.0281380

Methods

To analyze the import costs of green hydrogen via different energy carriers to Germany in 2050, the whole process chain from renewable generation to import is modeled. Therefore, four steps are conducted. First, detailed export costs for gaseous green hydrogen for 28 countries are derived from Franzmann et al. [9]. Based on the energy system properties of each country, the conversion costs to different energy carriers are determined. Haber-Bosch-synthesis for ammonia production, liquefaction for liquid hydrogen (LH2) and hydrogenation of LOHCs is considered. Based on shipping distances from each country to Wilhelmshaven (GER) [10] and shipping costs from Heuser et al. [5], the import costs of ammonia, LOHC and LH2 are calculated. Last, for each carrier type a reconversion step to gaseous hydrogen is taken into account. The techno-economic data for liquid hydrogen and LOHC are used from Heuser et al. [5] and Franzmann et al. [9]. The ammonia conversion steps are used from Nikhil et al. [11]. Due to the direct coupling of the here performed analysis with an energy system analysis from Franzmann et al. [9], relevant mechanisms like scaling effects and optimal utilization rate of conversions plants are included.

[9] doi.org/10.1016/j.ijhydene.2023.05.012
[10] https://sea-distances.org/
[11] doi.org/10.1016/j.ijhydene.2021.05.203

Results

The results show import costs starting at ~ 2.3 EUR/kgH2 for import of liquid hydrogen from Saudi Arabia and Oman (see figure 1). Generally, the costs for green hydrogen import as LH2 are the cheapest for each import country with ammonia only being competitive at large transport distances like import from Australia. The available hydrogen import energy is large compared to the expected import needs of a renewable Germany in 2045 of 400 PWh [12], so cost will be one decisive factor. The import costs for each carrier and import country are higher than German gaseous hydrogen costs of 2.3 EUR/ kgH2. Therefore, local hydrogen production is competitive with hydrogen imports via ship transport. Interesting import regions for Germany are solar rich regions like North Africa and MENA as well as hydrogen from wind resources from northern Europa. Also, low production cost of green hydrogen from Peru and Chile can be expected at costs of about 2.50 EUR/ kgH2.

For direct usage of ammonia and LH2, lower costs can be expected, as no reconversion to hydrogen is needed (figure 2). The lowest import costs can be expected for direct usage of liquid hydrogen at 2.32 EUR/kg LH2 followed by gaseous hydrogen at 2.34 EUR/kgGH2. The direct usage of ammonia at 74.1 EUR/MWhNH3 is 14% more expensive than using liquid hydrogen as an import carrier in 2050. Therefore, liquid hydrogen will still be the cheapest carrier type for vessel transport in the long run. As these results are depending on the techno-economic assumptions, there will be a discussion part of the most relevant impacts on import costs.

[12] https://www.fz-juelich.de/de/iek/iek-3/projekte/ksg2045-studie-fuer-deutschland

A fundamental outlook on European gas fundamentals and price for 2024 / 2025

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Keywords: Gas, LNG, Energy

Motivation

CIS will present a forecast for the European gas markets for years for 2024 and beyond.

Drawing on supply, demand and price development through the year-to-date, the paper will detail the likely outcomes for sectoral consumption, pipe and LNG sources of supply as well as storage inventories. Price predictions on the level of the out-tuning benchmark TTF will also be included.

Initially the paper will outline the current state of play with regards to European wholesale gas prices and how the summer has developed with regards to fundamentals.

It will then dive into a forecast of internal demand and provide colour as to how much gas the power, industry and residential-commercial sectors are likely to consume through to the end of March 2025. A focus on the petrochemical industry and its gas requirements will be outlined.

Moving to supply, the paper will then focus on two main areas: Russian pipe deliveries via Ukraine and LNG availability. Norwegian, Algerian pipe imports and domestic production will also be touched upon.

With the current five-year transit agreement between Russia and Ukraine due to expire at the end of 2024, the paper will outline the market scenarios with regards to flows via this route both stopping and continuing. How flows could continue even if Russian is not an active shipper will also be explained.

The paper will then focus on the role of the global LNG market and its winter fundamental balance which will impact both price and supply to Europe. Possible risks in the role of supply disruptions and demand spikes around the globe will be outlined. This could include commissioning delays to new liquefaction projects as well as unexpected rise in gas consumption in Asian markets.

Having considered both demand and supply, the paper will provide a forecast as to how storage fullness will develop through the year. The paper will the conclude with a prediction of where TTF could out-turn and how that compares with the current traded forward curve.

Methods

ICIS takes a cross-commodity approach to assessing European energy markets, shedding light on the interplay between gas, power, and carbon markets. Our European models take a common view on the price of commodities with a unified weather assumption that gives a clear and consistent integrated view of the market.

ICIS Gas Foresight provides traders and analysts with a daily forecast on the delivered, fair-value price of the ICIS TTF and other key hubs over the traded horizon. This is accompanied by a corresponding fundamental forecast for key European markets.

ICIS LNG Foresight gives traders and analysts a rolling 24-month global LNG forecast for both supply and demand, covering each liquefaction plant and importing market individually. The forecast builds on ICIS' deep insights into real-time LNG cargo-tracking as well as contracts and infrastructure databases.

Gas & LNG views are made consistent with ICIS modelling on power and carbon markets through model interactions (gas-to-power consumption). ICIS Power Foresight provides hourly-level forecasts for European power markets, from month+1 to year+3. ICIS EU Carbon Foresight combines quantitative and qualitative approaches to offer a holistic view on developments in the EU ETS and UK ETS. Our in-house suite of models captures the interactions of the EU ETS with national electricity markets and technology investments.

Results

Muted gas demand growth

All eyes will be on gas and power demand in 2024 as the market looks for signs of recovery that were conspicuously absent in 2023. The ICIS view is that industrial gas and power demand will start to revive in the second half of the year and into 2025, but the resurgence will be slow-going with very limited upside from the largest industrial consumption subsector of chemicals.

Undersupplied global LNG market to keep pressure on prices

The global LNG market is set to return to an undersupplied market in 2024, according to ICIS LNG Foresight data. LNG demand is forecast to climb 5% year on year to 424m tonnes (6,407 TWh), while LNG supply is expected to increase by 2% to 413m tonnes (6,241 TWh).

Bears remain in charge of gas prices

ICIS anticipates that European gas market will have weaker price upside in 2024 than previous years with the fundamentals rooted in bearish territory. The ICIS TTF Calendar Year 2024 expired at €33.575/MWh, shedding 57% of its value over the course of 2023. The majority of the losses were observed in the first half of the year while the Q1 ’24 and the Q2 ’24 were the component contracts which recorded the greatest losses year on year.

Low-carbon hydrogen imports to Europe: Case studies and transformation pathways for ramping up green and blue hydrogen

Nima Farhang-Damghani[1] (Speaker), Jonas Egerer[2], Philipp Runge[3]

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Keywords: Hydrogen Economy, Energy Import, Energy Transition, Blue Hydrogen, Green Hydrogen

Motivation

For the energy transition hydrogen and hydrogen carriers will become an important building block to defossilize many sectors such as energy, heating, industry and mobility. In light of the urgent global need to reduce greenhouse gas emissions and combat climate change, hydrogen emerges as a potent alternative to fossil fuels. According to the European Union the production target for low-carbon hydrogen in 2030 is 10 million tons and additionally 10 million tons of hydrogen imports, of which Norway is predicted to be a significant part of. This study presents a comprehensive analysis of the transition from natural gas to hydrogen (blue and green) as a pivotal move towards decarbonizing Europe's energy supply, with a specific case study focus on Norway's role as a primary energy exporter and as a suitable representative of further energy exporting countries. This research spans a significant timeframe, from 2024 to 2050, marking critical decades in the energy transition when the majority of Europe pledged to be carbon neutral. We assess the attractiveness of exporting blue and green hydrogen in competition to natural gas from Norway to Europe through various possible transportation modes (by retrofitted natural gas pipelines, new purpose-built pipelines or ammonia as a hydrogen carrier) in this transition period. We analyze this temporal transition from natural gas exports to hydrogen exports under different scenarios in a mixed-integer linear optimization model. Our results show, that this transition from an energy exporter perspective will take place under very different timeframes from natural gas to blue or/and green hydrogen and that the switching times are heavily dependent on factors such as CO2 pricing, capital cost developments and natural gas prices.

Methods

For the analysis in this research, we created a mixed-integer linear optimization model in the General Algebraic Modeling System (GAMS) environment. The objective function in this model is to maximize profits for the modeled country's energy exports which includes the export of natural gas, blue hydrogen and green hydrogen over the whole timeframe from 2024 to 2050. The optimization model incorporates a variety of constraints, for example transport capacities and the inherent limitations in retrofitting existing natural gas pipelines for hydrogen transport. We also integrated a detailed sensitivity analysis to analyze the impact of pivotal parameters, including but not limited to, natural gas prices, CO2 pricing, hydrogen prices (which are influenced by CO2 pricing and natural gas prices), and various capital costs. Generally, we presume a constant annual export of energy that can be composed of natural gas, blue hydrogen and green hydrogen. The composition of energy exports is calculated endogenously as well as all required capacities along the supply chain. For blue hydrogen the required carbon infrastructure is also taken into account. For green hydrogen we have considered the use of PEM electrolysis and possible hybrid renewable electricity supply from PV, onshore wind as well as offshore wind. The model is also applicable to further countries and hydrogen derivatives.

Results

Key results highlight the feasibility and economic viability of transitioning from natural gas to hydrogen, with a specific emphasis on the role of Norway in a case study. The analysis reveals that while the transition is robust under a range of scenarios, it is particularly sensitive to fluctuations in natural gas and hydrogen prices, CO2 pricing, and the associated capital costs of electrolyzers and renewable electricity supply. Moreover, the study delves into the concept of stranded investments and lock-in effects, particularly for blue hydrogen production, providing insights into risks by investing into potentially short-lived blue hydrogen plants. The results also underscore possible pathways to fully transition into green hydrogen exports with blue hydrogen as a transitional means of hydrogen supply and the different onset of ramping up blue or green hydrogen production depending on our scenario analysis. In some cases, we can show, that natural gas exports would continue until a total depletion of Norwegian natural gas reserves before hydrogen exports are considered under a loss of profits. The results thus show, that depending on the scenario, different political measures such as CO2 pricing may have to be more ambitious than usually projected for the transition to initiate earlier and reach a natural gas phase out by 2050.

Session 11:15 – 12:15
Renewable energy outlook

Room: HSZ/301/U
Chair: Dimitrios Glynos

Does cross-border electricity trade stabilize the market value of wind and solar energy? Insights from a European panel analysis

Clemens Stiewe, *Hertie School*

Mine water geothermal energy - abandoned mines as a green energy source

Fritz Raithel, *TU Bergakademie Freiberg*

100% renewable energy system in the EU - Implications for infrastructure policy

Niels Kunz, *University of Technology Berlin*

Does cross-border electricity trade stabilize the market value of wind and solar energy? Insights from a European panel analysis

Clemens Stiewe[1] (Speaker), Alice Lixuan Xu[2], Lion Hirth[3], Anselm Eicke[4]

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Keywords: Renewable energy, market value, cannibalization effect, cross-border trade, electricity

Motivation

The market value of wind and solar energy tends to fall with increasing market shares – and market shares have increased substantially across Europe. At the same time, European electricity markets have become more interconnected. So far empirical studies have focused on the effect of domestic renewable generation on the market value of renewable energy. In this paper, we study cross-border effects that impact the value of renewable energy. In particular, we estimate spillovers of renewable energy cannibalization across bidding zones and assess the moderating effect of connectedness on the value drop of renewable energy. We explore these questions through spatial panel regression, using monthly data from 30 European electricity bidding zones spanning from 2015 to 2023. To isolate the effect of connectedness we control for other moderators of the value drop, such as flexible hydropower, the simultaneity of electricity consumption and renewable generation, the variability of renewable generation, as well as fuel and carbon prices. Moreover, we control for the effect of wind on the value of solar, and vice versa.

Methods

Cross-border flows and hydro electricity generation are endogenous to electricity prices, which determine the market value. To estimate a causal effect of connectedness and hydro flexibility on market value we use normalized total interconnector (hereinafter: trade capacity) and hydro capacities instead. This approach gives a set of variables that are either nearly invariant over time or across price zones. We use a within-between random effects model to exploit this variation at different levels (Mundlak, 1978; Bell & Jones, 2015; Wooldridge, 2019).

In addition to the domestic effects of renewable penetration on value factors, we model spillover effects of renewable generation between neighboring and interconnected European electricity markets by applying the spatial lag of X approach (Anselin et al., 2008; Elhorst, 2014; Beenstock & Felsenstein, 2019). This approach allows to capture spillover effects between panel units by including the values of independent variables in geographically adjacent panel units. To correct for price fluctuations following business cycles we use the value factor (or capture rate), i.e. the ratio of wind and solar market value and base prices, as our dependent variable.

Results

We find a significant and sizable cannibalization of renewable energy across European markets. For a one percentage point (p.p.) increase of wind penetration, the wind value factor drops by 0.5 p.p. A one p.p. increase in spatially lagged wind penetration is associated with a 0.4 p.p. drop in domestic value factors. Confirming earlier studies, we find a stronger effect for solar energy, which reduces its value factor by 1.3 p.p. per one p.p. increase in domestic and neighboring solar penetration (López Prol et al., 2020).

Connectedness mitigates the domestic cannibalization effect and exacerbates the spillovers of neighboring cannibalization. Figure 1 shows the conditional effects of domestic and spatially lagged wind penetration at different levels of normalized trade capacity. This likely reflects the price-lifting effect of exports and the price-depressing effect of imports, respectively. Flexibility within a price zone proves to be another important moderator of the cannibalization effect: Higher pumped storage and reservoir hydro capacity both mitigate the value drop of wind energy, while we only find a significant and smaller effect on solar value factors for pumped storage. A stronger correlation of renewable generation and electricity consumption at the hourly level mitigates the value drop of wind energy, which corroborates previous findings (Liebensteiner & Naumann, 2022; Ruhnau, 2022). A higher variation in hourly generation, on the other hand, is associated with a steeper drop of wind and solar value factors when their market penetration increases.

Our findings suggest that the simultaneous buildout of wind and solar energy across Europe adds to the well-known challenge of domestic cannibalization. Higher connectedness both mitigates domestic cannibalization and exacerbates cannibalization spillovers, thus stabilizing renewable market value for net exporters of renewable electricity and causing a steeper drop in market value for net importers.

Mine water geothermal energy - abandoned mines as a green energy source

Fritz Raithel[1] (Speaker), Lukas Oppelt[2], Timm Wunderlich[3], Tom Ebel[4], Thomas Grab[5], Prof. Dr.-Ing. Tobias Fieback[6]

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Keywords: mine water, geothermal energy, heat pump, district heating cooling

Motivation

Mining has influenced and shaped the development of humankind for thousands of years. Raw materials are still being extracted in mines around the world today. After closure, these mines are often flooded and then offer a very high potential as a renewable energy source for heating and cooling.

Mine water is an ideal source of energy for heating and cooling due to the almost constant water temperatures throughout the year and the large rock surfaces that act as heat transfer surfaces. Large bodies of mine water with temperatures between 10 and 30°C can provide vast amounts of thermal energy that can be used as an efficient and sustainable resource for heating or cooling industries or districts, for example in the German Ruhr area and the Erzgebirge. This offers a positive additional effect of the eternal task for old mining areas. [1]

Methods

A number of pilot plants have already been commissioned, particularly in North America and Europe. These existing and planned mine water geothermal plants worldwide were examined in a literature review. In addition, specific potential studies for individual sites were analysed and key parameters such as temperature level, flow rate and potential output were recorded. The five largest of the 111 sites studied are presented in detail in this conference presentation.

Results

The construction of new plants is often hampered by the fact that mine water is in competition with fossil fuels such as natural gas or fuel oil and is compared on economic and environmental criteria. Scientific comparison reveals that ordinary groundwater heat pumps and pellet heating systems powered by bio-energy have relatively low operating costs. Under the selected general conditions, fossil energy sources such as heating oil, natural gas, or fossil district heating result in higher annual costs. The annual operating costs are significantly influenced by the energy efficiency ratio and the electricity price to be paid. Both factors are equally relevant for the economic efficiency of the system, as demonstrated by an exemplary mine water system. Three constructed scenarios with different operating costs are used to illustrate the relationships. The variables that influence the annual performance factor include the temperature deviation between the mine water temperature and the flow temperature, the length of the heat transport path, and the influence of hot water preparation, among others. Additionally, the electricity price is also a significant factor. Current developments, such as the integration of a CO2 tax, are also included in the analysis.

100% renewable energy system in the EU - Implications for infrastructure policy

Fabian Präger[1], Niels Kunz[2] (Speaker), Christian von Hirschhausen[3]

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Keywords: Energy Infrastructure, 100% Renewable Energy System

Motivation

In response to climate and geopolitical energy crises, energy supply in the European Union (EU) must manage a profound transformation towards decarbonisation (Hainsch et al. 2020; Pedersen et al. 2022; Pickering, Lombardi, and Pfenninger 2022; Auer et al. 2020; Victoria et al. 2020; Achakulwisut et al. 2023). While the expansion of renewable energies continues, the expansion of fossil natural gas infrastructure is also being driven forward in Europe, putting the energy transformation at risk (Kemfert et al. 2022). The transformation of the EU's energy system from its historically fossil- and fissile-centric infrastructure towards a 100% renewable, fossil-free and fissile-free model, aiming for decentralization where feasible (Kendziorski et al. 2021), relies heavily on the establishment of interconnected energy infrastructure capable of accommodating 100% renewable energy systems. Typically, attention is directed towards the deployment of extensive electric and gas grids across Europe to effectively balance the intermittency of weather-dependent solar and wind electricity, also a primary focus of our study. Moreover, we examine the development of infrastructure pertaining to hydrogen, oil, and CO2, domains frequently overlooked within the context of energy infrastructure development amidst the socio-ecological transformation. The predominant paradigm in energy infrastructure development often adheres to the notion of "more infrastructure equates to better outcomes". Contrary to this stance, our study challenges such an approach, particularly emphasizing the benefits of decentralized approaches over centralized ones in the establishment of novel energy infrastructure. Based on our investigations, we are developing the foundations for energy infrastructure planning in the 21st century (Präger et al. 2023).

Methods

We survey national and European policies in the field of infrastructure policy over the last 30 years and subject them to institutional economic analyses. Our methodology allows us to derive institutional economical implications for infrastructure policy in the EU. We take a sectorwise approach, including electricity, gas, hydrogen, oil and CO2 (CCTS) infrastructure.

Results

Examining the existing regulatory framework, we identify shortcomings within the Trans-European Networks for Energy (TEN-E) regulation. There is a notable inadequacy in its alignment with recent climate and energy targets, coupled with a lack of responsiveness to the impact of the COVID-19 pandemic and geopolitical events. Furthermore, the continued support for fossil fuel networks within this framework presents a significant obstacle to achieving sustainability goals.

Integrated planning emerges as a critical solution to address inefficiencies stemming from separate infrastructure planning by electricity, gas, and future hydrogen grid operators. Advocating for stronger European-wide integrated planning, we emphasize the potential synergies that can be harnessed for the electrification of heat, transport, and industry sectors.

We see a clear risk of undermining EU climate targets and exacerbating the cost of the energy transition without momentum towards establishing an EU-wide energy regulator to oversee infrastructure decisions. We shed light on the urgency for collaborative efforts to address challenges and leverage opportunities in energy infrastructure development, ultimately advancing the EU's sustainability agenda while ensuring energy security and resilience.

Session 11:15 – 12:15
Electricity markets and pricing schemes

Room: HSZ/304/Z
Chair: Hannes Hobbie

Preventing winners' default in procurement energy auctions. Theory, simulations and experiments

Silvester van Koten, *University of Jan Evangelista*

Technical aspects of implementing dynamic electricity prices in the context of a local electricity market

Friederike Reisch, *Reiner Lemoine Institut*

Identifying elasticities in autocorrelated time series using causal graphs

Jorge Sánchez Canales, *Hertie School*

Preventing winners' default in procurement energy auctions. Theory, simulations and experiments

Silvester van Koten[1] (Speaker), Bert Willems[2]

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Keywords: -

Motivation

We study and compare the impact of the possibility of default in renewable energy procurement auctions and to gain insight in the effectivity of different measures. This is a highly topical issue, as especially governments commit for billions of euros services to private suppliers and suppliers default on their commitments relatively often.

Methods

We use theory to analyse the analytical structure of payoffs for the auctioneer and the private suppliers. We then use numerical simulations to illustrate the core relationships.

Results

We find that with increasing variance of the suppliers' cost components, the likelyhood of default increases. A crucial factor influencing this likelyhood is the ratio of post-auction variance in the winners' costs to the variance of suppliers' pre-auction costs. A higher ratio correlates with a heightened likelyhood of default. Notably, the likelyhood of default is not influenced by the direction of expected cost changes, whether to increase or decrease. This phenomenon arises from the auction effectively make bidders competing away most of the trade surplus.

Three measures stand out as positively influencing the outcomes, ranked in descending order of welfare improvement for the government: financial bonds, an entry fee, and physical pre-investment. See the figure below for the physical pre-investment (PPQ) and financial bonds (FB). These measures operate through distinct mechanisms, providing an opportunity to test the theory through experimentation.

The measures are predicted to result in different outcomes not only in welfare, price and default likelyhood, but also in bidding behavior. Specifically, in a second-price auction, suppliers are predicted to bid above their costs when financial bonds are involved, whereas they are expected to bid below their costs with an entry fee and physical pre-investment. This is attributed to the fact that the expenses for the entry fee and physical pre-investment are sunk costs, rendering them irrelevant for bidding. In contrast, the expenses for the financial pre-investment are not sunk and thus represent opportunity costs that affect bidding. An experimental study to further validate the results is in the design phase. We will present the basic computer interface we will present to the experimental subjects in our study.

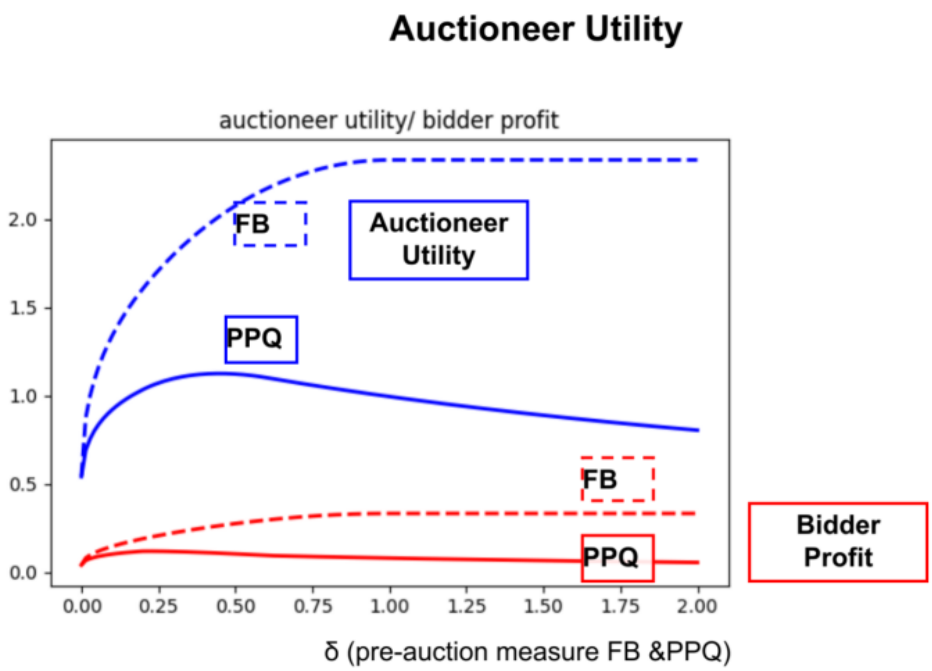

Figure 1

Technical aspects of implementing dynamic electricity prices in the context of a local electricity market

Friederike Reisch[1] (Speaker), Jan-Timo Meyer[2], Godwin Okwuibe[3], Felix Förster[4],

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Keywords: local electricity markets, dynamic prices, dynamic grid fees, flexibility

Motivation

In order to achieve the goal, to almost completely, cover electricity consumption with Renewable Energy Sources (RES) by 2035 and enable a stable, efficient and affordable electricity supply, the demand for electricity must become more flexible. Small and medium sized businesses as well as households can play a major role here, if their flexibility can be activated. The German government is therefore obliging all electricity suppliers to offer a dynamic electricity tariff from 2025 on. In order to have sufficient capacity available to transport electricity from producers to consumers, transmission and distribution grids must be expanded. Combinations of dynamic electricity tariffs and load-based grid charges are particularly efficient, reduce economic costs and result in lower electricity prices for all electricity customers. In addition, local price signals, e.g. local marginal prices (LMPs) can reduce curtailment costs as well as investment costs in RES, storage and grid expansion. Local electricity markets not only address the technical but also the political and social challenges of the energy transition by strengthening citizen participation and acceptance of the energy transition. Additionally, local markets serve as direct marketing of electricity from small and medium-sized enterprises, citizen energy plants or private households. Despite the indications of many studies and pilot projects, local electricity markets and dynamic tariffs have so far only been implemented to a very limited extent and their system-serving potential has not been exploited. This study uses the experiences from the BMWK-funded BEST project (blockchain-based decentralized energy market design and management structures) to examine how far the existing technical solutions for implementing such concepts are and which development gaps need to be closed to enable widespread implementation.

Methods

The results and experiences from the BEST project will be used to determine the extent to which the technical, legally compliant and economic implementation of local electricity markets is currently possible. The project used literature research, stakeholder workshops and surveys to develop a market design for a local electricity market that can contribute to supporting an effective, secure and affordable electricity supply with 100% RES. The most important characteristics and premises identified were dynamic electricity prices, variable grid charges in terms of time and space, and real-time trading. The actors and components of the developed trading system and their interactions are shown in Figure 1. The necessary software components were implemented, hardware requirements specified and a hardware-in-the-loop simulation environment set up. The functionality of the software components and the overall system was evaluated in this environment. The simulation environment is also used to train machine learning models and offers the option of time-lapse operation. This means that electricity trading over several years can be simulated in a matter of days. For example, seasonal market dynamics can be analysed. For the real implementation of electricity trading, centrally operated software components were used on a secure IT infrastructure with secure interfaces and made accessible to market participants. The necessary hardware was installed at the market participants and also connected on the software side. The corresponding processes for registering and managing customers were integrated into the internal processes by the energy supplier in its role as market operator and a concept for post-settlement was created. The experience gained over the last 3 years in implementing these steps is documented and evaluated in expert interviews with the respective responsible persons.

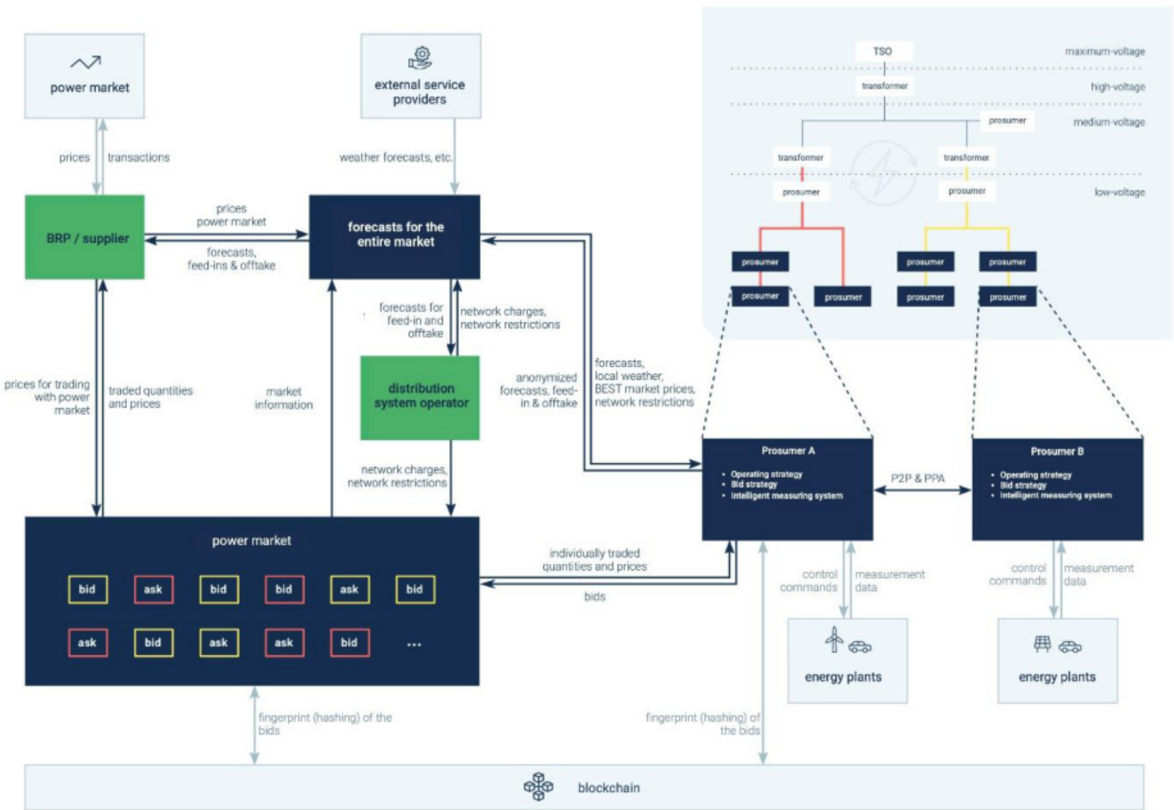

Figure 1

Results

We show which aspects of the implementation of the local electricity market described above work to what extent and where the most relevant hurdles currently lie. The development of the individual components (security architecture using oAuth2, implementation of a market with corresponding logic, local schedule creation) of the outlined trading system and the legally compliant embedding in the energy industry can be assessed as uncritical but possibly elaborate. However, most aspects of the implementation have been technically solved to a limited extent, as individual solutions and partial workarounds resulted in a functioning trading system. Scalability, economic operation or customer benefits are currently only given in individual cases. The most important development gaps identified in the project were: In most cases, the necessary IT infrastructure has to be completely procured and, in some cases, connected at great expense. This poses both an economic and a logistical problem, as individual solutions have to be found on site by trained personnel and there are as yet no processes in place for nationwide installation. The development of manufacturer-independent (home) energy management systems (H)EMS with the corresponding interfaces and standards has not yet progressed far enough to take on the necessary tasks. The use of machine learning methods should be mentioned. In most cases, the data required to train models for consumption time series predictions is not available. Predicting prices on markets that have only recently come into existence and whose mechanisms and interactions have not yet been tested over many years is an even greater challenge. How communication with the distribution grid operator will work is still completely unregulated. Furthermore, it is not yet foreseeable that it will be possible to structure grid fees in a way that incentivises electricity trading that prevents or reduces congestion.

Identifying elasticities in autocorrelated time series using causal graphs

Silvana Tiedemann[1], Jorge Sánchez Canales[2] (Speaker), Felix Schur[3], Jonas Peters[4], Raffaele Sgarlato[5], Lion Hirth[6]

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Keywords: elasticity of demand, electricity markets, direct acyclic graphs, causal inference, instrumental variables

Motivation

The quantification of price elasticity of demand has captivated economists for decades, offering critical insights for sectors such as electricity where it influences peak capacity predictions, customer price exposure impacts, and market modeling inputs. Despite its significance, the estimation techniques using aggregated observational data remain fraught with methodological challenges, leading to potential biases in parameters used by entities like transmission system operators. These biases question the accuracy of current demand elasticity inputs, highlighting a gap in our understanding and methodology.

Methods

This study innovates by applying causal graphs to articulate the challenges in estimating price elasticity of demand from aggregate data. This graphical approach demystifies the shortcomings of conventional instrumental variable estimations, which fail to account for structural dependencies of current demand on past demand. By integrating advancements in causal inference, we propose valid estimators that consider potential structural autocorrelation. The methodology's robustness is demonstrated through simulations and a practical application to German electricity demand data.

Results

Our findings underscore the criticality of accounting for temporal dependencies in high-frequency contexts like the electricity market, where overlooking such factors can significantly bias elasticity estimates. Contrary to previous assertions, our analysis of the German electricity market reveals that elastic demand contributes to a modest peak capacity reduction of merely 0.4%, starkly lower than earlier estimates. This revelation not only challenges existing paradigms but also provides a nuanced understanding crucial for policymakers and system operators.

Keynote II 13:15 – 14:00

Room: HSZ/004/H, hybrid
Chair: Prof. Dr. Christian von Hirschhausen

Exploring residential energy demand dynamics in the context of the energy transition

Prof. Dr. Russell McKenna[1]

[1]*ETH Zürich*

Session 14:05 – 15:35
Energy system modeling II

Room: HSZ/004, hybrid
Chair: Veronika Lenivova

Energy demands for negative emissions and CO2 supply in future German energy systems
Thomas Schöb, *Forschungszentrum Jülich*

Bridging the supply-demand gap: Techno-economic analysis of Uganda's electricity expansion plan
Galila Khougali (***online contribution***), *University College London*

Regional implications for the German electricity system with the energy transition in a European context
Jonas Egerer, *FAU Erlangen-Nürnberg*

Mitigating future variable renewable energy sources curtailment in Poland through demand-side management strategies
Marcin Pluta, *AGH University of Krakow*

Energy demands for negative emissions and CO2 supply in future German energy systems

Thomas Schöb[1] (Speaker), Henrik Wenzel[2], Felix Kullmann[3], Jann Weinand[4], Detlef Stolten[5]

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Keywords: Negative Emissions, Direct Air Capture, Biomass with carbon capture, CO2 Supply, Energy system analysis

Motivation

Since the amendment of the Federal Climate Change Act in 2021, various studies have investigated pathways towards Germany's greenhouse gas-neutrality by 2045. While the depicted transformation pathways for the German energy system [1], [2], [3] differ in various aspects, all studies agree that technical solutions for the provision of negative emissions are needed to offset remaining emissions in the year 2045. However, only the studies by Stolten et al. [2] and Prognos et al. [3] account for the additional energy demand for Direct Air Capture (DAC) of CO2, which is not only used for provision of negative emissions but also for the supply of CO2 as feedstock for the chemical industry. Biomass with carbon capture (BECC) is another option for the provision of negative emissions and is widely used in the studies, but it is not quantified how much biomass will be needed for these process routes. Thus, a complete assessment of the energy demand for the provision of negative emissions and for the CO2 supply of the chemical industry is missing. In this study, we use an integrated energy system model for Germany to develop scenarios for future energy demands to capture CO2 and for biomass usage in BECC processes in the year 2045.

[1] S. Lübbers et al., Vergleich der 'Big 5' Klimaneutralitätsszenarien, Mar. 2022. Accessed: Feb. 04, 2024. Available: https://ariadneprojekt.de/media/2022/03/2022-03-16-Big5-Szenarienvergleich_final.pdf

[2] D. Stolten, P. Markewitz, T. Schöb et al., Neue Ziele auf alten Wegen? - Strategien für eine treibhausgasneutrale Energieversorgung bis zum Jahr 2045. in Schriften des Forschungszentrums Jülich, Reihe Energie & Umwelt, no. 577. Jülich, 2022. Available: https://juser.fz-juelich.de/record/908382

[3] Prognos, Öko-Institut, and Wuppertal-Institut, Klimaneutrales Deutschland 2045. Wie Deutschland seine Klimaziele schon vor 2050 erreichen kann, Study on behalf on Stiftung Klimaneutralität, Agora Energiewende und Agora Verkehrswende, Berlin, 2021

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, storage facilities and energy demands. Furthermore, greenhouse gas emissions from agriculture and waste treatment are included in the emission balance of the optimization model. To offset remaining emissions, the model includes technologies to capture CO2 directly from the atmosphere (DAC) or from biomass-fired point sources (BECC) and store it permanently in geological storage sites in Germany [5]. Additionally, demands in the chemical industry for CO2 as feedstock are included in the model.

The four investigated scenarios in this study focus on a greenhouse gas-neutral Germany in the year 2045 and consist of a cost-optimal scenario, a scenario with limited availability of biomass, a scenario with limited availability of BECC options and a scenario including the provision of negative emissions by natural solutions like rewetting of peatlands or afforestation. As the DAC technology plays a major role in some scenarios, an additional model for a detailed assessment of DAC systems is currently developed. This subsequent optimization model will be used to analyze the energy demand of DAC plants in Germany depending on weather conditions.

[4] F. Kullmann, P. Markewitz, L. Kotzur, and D. Stolten, The value of recycling for low-carbon energy systems - A case study of Germany's energy transition, Energy, vol. 256, p. 124660, Oct. 2022, doi: 10.1016/j.energy.2022.124660.
[5] T. Schöb, F. Kullmann, J. Linßen, and D. Stolten, The role of hydrogen for a greenhouse gas-neutral Germany by 2045, Int. Journal of Hydrogen Energy, vol. 48, no. 99, pp. 39124–39137, Dec. 2023, doi: 10.1016/j.ijhydene.2023.05.007.

Results

The optimization results of the ETHOS.NESTOR model show that in the cost-optimal scenario in the year 2045, about 116 Mt CO2 are captured from point sources or directly from the air. The chemical industry uses 26 Mt of the captured CO2 as a feedstock, while 90 Mt CO2 are permanently stored in geological storages. DAC from the atmosphere supplies about 39 Mt CO2, while capturing industrial process emissions and emissions from waste powerplants accounts for about 19 Mt

CO_2. These capture processes lead to an electricity demand of 17 TWh and a heat demand of 82 TWh (see Table 1), where the heat is needed for the regeneration of the adsorption filters and absorption materials. However, with about 58 Mt CO_2 biomass-fired processes with carbon capture account for half of the captured CO_2 as it will be more cost-effective than capturing CO_2 directly from the air. Thus, about 42 % of the available bioenergy in the year 2045 is used in these BECC processes. Limiting the biomass availability to the currently cultivated area for bioenergy, reduces the available bioenergy to 315 TWh and the biomass usage in BECC processes by 27 %. Therefore, DAC plants must capture 14 Mt CO_2 in addition to the cost-optimal scenario and the electricity and heat demands increase correspondingly (see Table 1). In the scenario with limited availability of BECC options only 20 Mt CO_2 are captured by BECC, while DAC plants capture 81 Mt CO_2 from the air. This leads to a doubling of the electricity demand and an increase of the heat demand by 84 %. If natural emissions sinks can provide 40 Mt CO_2 of negative emissions as demanded in the Federal Climate Change Act, direct air capture of CO_2 is not required for the provision of negative emissions. Preliminary results of the detailed DAC system model indicate that temperature and relative humidity influence the energy demands for capturing CO_2 directly from the air and that could lead to higher DAC energy demands than shown in Table 1.

Table 1: Energy demands and biomass usage in the investigated scenarios for provision of negative emissions and for CO_2 supply for the chemical industry in the year 2045

Scenario	Cost-optimal	Limited biomass availability	Limited availability of BECC	Including natural emissions sinks
CO_2 captured by DAC plants	39 Mt CO_2	53 Mt CO_2	81 Mt CO_2	0 Mt CO_2
CO_2 captured by BECC	58 Mt CO_2	44 Mt CO_2	20 Mt CO_2	57 Mt CO_2
Electricity demand	17.1 TWh	22.5 TWh	34.3 TWh	1.1 TWh
Heat demand (~100 °C)	81.6 TWh	104.2 TWh	151.1 TWh	15.8 TWh
Biomass usage in BECC processes	176.3 TWh	128.2 TWh	63.5 TWh	174.1 TWh

Table 1

Bridging the supply-demand gap: Techno-economic analysis of Uganda's electricity expansion plan

Galila Khougali[1] (Speaker), Catalina Spataru[2]

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[2]*University College London*

Keywords: East Africa, Sustainable Energy Access, Energy Policy, PLEXOS, Capacity Expansion Model

Motivation

Eastern African countries are one of the fastest growing economic regions, yet it is still suffers from a gap in electricity supply and demand, which has significant impact on its economic development. The mounting pressures of growing populations and economic activities, and global efforts to transition towards clean energy also mean countries would need to explore clean electricity generation technologies that are equally economically viable for a growing electricity demand. One recent development has come from Uganda, which proposed its Energy Transition Plan, outlining strategies to close the energy access gap, enhance economic development, and promote clean energy for a just transition. Similar to many countries in the region, hydro power makes over 85% of all generation, exposing Uganda's energy system to risks from increasingly severe droughts and seasonality. On the demand side, pressure from growing electricity demand, projected to increase by almost 10% from 2015 to 2025, and further by another 10% in the following decade. Therefore, expanding clean energy generation is a key policy objective aimed to bridge the electricity supply-demand gap.

The clean energy potential in Uganda presents opportunities in energy capacity expansion and meeting electricity demand, which can place the country in a trajectory towards sustainable development and energy security. To this end, this paper explores Uganda's power system by conducting a techno-economic dispatch modelling assessment under business-as-usual and high renewable energy penetration scenarios. While several studies have contributed to an understanding of Uganda's electricity system, to our knowledge, no research has taken into account the hourly electricity demand, and the high penetration of solar energy as outlined in Uganda's policies. This research makes contributions in capturing hourly electricity demand, while also exploring the policy-driven generation scenarios and the techno-economic impacts.

Method

The study employs PLEXOS Integrated Energy Model to simulate the proposed power plants across different scenarios. Specifically, the Long Term (LT) Plan within PLEXOS is utilized to optimize the expansion of generation capacities spanning from 2020 to 2040. Within this framework, the simulation of power plants was based on anticipated national capacity expansion initiatives. The overarching objective of this simulation is to furnish insights into the proposed plans, while capturing the impact of variables such as electricity demand, generation capacity, and transmission infrastructure. PLEXOS' Long Term (LT) Plan highlights the most economically viable expansion strategy between the scenarios within predefined cost constraints to achieve stipulated electricity access targets and meet the hourly electricity demand.

The input data for the simulation is derived from the inventory of committed and planned power plant projects as outlined in the policy objectives. Two principal scenarios were constructed for comparative analysis: the Business as Usual (BAU) Scenario and the High Renewable Penetration Scenario (HRPS). The former encapsulates the anticipated progression of power plants, primarily emphasizing hydroelectricity projects. In contrast, the latter scenario reflects a more diversified electricity generation portfolio, with increased penetration of solar energy alongside a proportionate presence of hydroelectric power generation with storage capacities.

Results

In this study, the electricity system in Uganda has been modelled in a techno-economic dispatch model to meet the hourly electricity demand. The model, PLEXOS, captures the short and long term power expansion planning, which will likely highlight the variation of electricity cost under the different generation expansion scenarios. The results will likely reflect the growing electricity demand anticipated to occur in Uganda, and also reflect the hourly solar photovoltaic output fluctuating across the day. The results may also show that although several power plant projects are under way and in planning process, much more electricity generation will be required to meet the demand. The clean energy potential in Uganda is significant, particularly hydro power which is technologically possible to reach an output of 20 TWh/year, however, a high reliance on hydropower may come at the cost of a more resilient power system. Hence, the results will likely highlight that increasing solar energy generation provide an economic substitute of generation expansion. Additionally, coupling hydro power that has storage capacities with an intermittent energy generation such as solar energy can provide system flexibility and facilitate meeting fluctuating hourly electricity demand. Furthermore, although Uganda has some geothermal energy potential, the capital costs of this technology may appear less viable than other generation technologies such as solar energy or hydro power. Nevertheless, a diversified generation mix means a more resilient power system that is less susceptible to disruptions such as draughts, which have previously disrupted the power system.

Regional implications for the German electricity system with the energy transition in a European context

Jonas Egerer[1] (Speaker), Ulrike Pfefferer[2], Lukas Lang[3], Veronika Grimm[4]

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Keywords: investments, 2030, coal phase-out, renewables, Germany, Europe

Motivation

The transformation of the European electricity system towards non-fossil energy sources takes place in an electricity market with bidding zones. In most cases, the bidding zones still follow national borders instead of regional and temporal surplus or scarcity in supply and demand. This raises questions on the efficiency of market incentives for investment and operation decisions for flexible supply and demand installations within each bidding zone. One important example is the German electricity market which can be seen as a show case due to the upcoming coal phase-out with the fast transition towards renewables and the consequently required investments in regional flexibility. In the short-term, market results on the spot market neglect internal constraints in the transmission network. Therefore, market outcomes are often infeasible in the physical electricity system and require costly adjustments. An increasing demand for congestion management has already been observed, with rising costs for adjusting market outcomes as well as an increasing need for network expansion, which is expected to continue in the future. In the long-term market equilibrium with investment, the investors in renewable capacity, (fossil or renewable) gas power plants and various other flexibility options (e.g., electrolysis capacity) do not observe regional scarcity signals for their investment decisions from the spot market. This can result in inefficient spatial investment and also an inefficient composition of technologies due to the correlation of spatial and temporal market prices.

Methods

In our work, we analyze the German electricity market in a European context within a two-level electricity market model. At the first level, the model allows private firms to decide on their long-term investment decisions in spatial and temporal flexible generation and demand capacities considering the resulting market equilibrium in the European electricity market. Trading between bidding zones is considered with inter-zonal trade capacities. At the second level, we evaluate market outcomes for a core region with a more detailed spatial resolution. In our case study, we look at Germany with higher spatial granulation (11 zones), take the market outcomes of the spot market, evaluate the spatial location of installations within the German electricity system and determine resulting transmission constraints and least-cost congestion management. For investments without spatial incentives, we assume different tie-breaking rules for their allocation to the 11 zones. In order to compare investment and operation outcomes to the first best, we compare results to a nodal pricing model for Germany on the spot market (11 zones) and optimal allocation within Germany of investment levels determined in a zonal electricity market.

Results

The application uses an aggregated data set of the European electricity system for the target year 2030. The first preliminary results show that from a system-optimal perspective and despite of an early coal-exit in Germany, additional investments in gas power plants are especially needed in the south of Germany whereas new flexible demand (e.g., electrolysis capacity) is more beneficial in the north. It is expected that network congestion and redispatch cost decrease since investments are placed in regions with either a scarcity or surplus in electricity production. The current lack of regional incentives in the uniform bidding zone raises concerns if this spatial allocation which is beneficial for system efficiency can be reached. In case of inefficient placements and technology choice we can show that the system, in addition to the spot market outcomes, requires procurement of investment in additional flexibility with related costs to allow for physically feasible system operation.

Mitigating future variable renewable energy sources curtailment in Poland through demand-side management strategies

Marcin Pluta [1] (Speaker), Artur Wyrwa [2], Janusz Zyśk [3], Maciej Raczyński [4]

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Keywords: Renewables, Curtailment, Demand-Side, Load Shifting, Power System

Motivation

Renewable Energy Sources (RES) account for an increasing share of electricity generation in the Polish power system. In 2023, the electric capacity installed in Variable RES (VRES) was 9.7 GW and 13.8 GW in onshore wind turbines and photovoltaic installations, respectively. These sources generated ca. 35 TWh of electricity. Although no official statistics are kept on the curtailment of RES generation, in 2023 the Transmission System Operator (TSO) published three announcements for respective three days when such generation reduction occurred. In these days, during the hours of reduced generation, VRES production accounted for approximately 60% of electricity demand. It is expected that by 2050 the electric capacity installed in VRES in Poland will significantly increase. In the last two years, capacity increments have reached approximately 1 GW annually for onshore wind turbines and three times more for photovoltaics. The projected future development of these sources, along with available estimates of the potential of offshore wind energy in the Polish Economic Zone of the Baltic Sea, suggest that by 2050, around 80 GW of VRES could be installed, with 20 GW offshore, 20 GW onshore, and 40 GW in photovoltaics. This raises the question of whether, with such significant growth in VRES, there will be more hours of VRES generation curtailment? How effectively the introduction of selected demand-side management (DSM) strategies can mitigate this curtailment?

Methods

At first, simple simulations of the power system operation were carried out based on the characteristics of VRES operation (hourly capacity factors of VRES) and the system load profile from 2023, assuming that VRES capacity will be increased up to 80 GW and the annual electricity demand will reach the value according to the National Trends scenario (ENTSEO-E 2022) for 2050, i.e. 232 TWh. These analyses aimed to demonstrate how the growth in VRES capacity without proper demand-side management would affect the number of hours with generation curtailment and to estimate the amount of ungenerated electricity. In the second part of the study, the operation of the system was optimized using the MEDUSA model, which belongs to the class of UCED models. Two DSM strategies were examined in the model. The first strategy, namely strategic growth, assumed that the need for decarbonizing the economy, especially industry, through the use of green hydrogen produced in electrolyzers, will lead to a general increase in electricity demand by ca. 150 TWh in 2050. The second strategy introduced was load shifting. It was assumed that the demand magnitude could change by a maximum of 10% of the expected peak demand, i.e., by approximately 4 GW, in each hour of the day. Additionally, the MEDUSA model assumed a development path for energy storage, mainly pumped hydroelectric power plants and electrochemical storage facilities, resulting in the installation of approximately 10 GW by 2050 with an average discharge time of 8 hours.

Results

The simulations conducted in the first part of the study for 2050 showed that with the assumed growth in VRES capacity and a demand level of 232 TWh, the number of hours with VRES generation curtailment, without implementing DSM strategies, could range from 2800 to over 4000 hours. The implementation of DSM strategies analyzed in the study significantly reduced the occurrence of VRES generation curtailment.

Session 14:05 – 15:35
Residential energy systems I

Room: HSZ/405/H, hybrid
Chair: Jens Maiwald

Power sector impacts of a simultaneous European heat pump rollout

Alexander Roth, *DIW Berlin*

Leveraging smart meters to analyze price sensitivity under telescopic tariffs in India

Madhav Sharma, *Indian Institute of Technology*

Trade-offs between system cost and supply security in municipal energy system design: an analysis considering spatio-temporal disparities in the Value of Lost Load

Febin Kachirayil, *ETH Zurich*

Residential battery flexibility: Spot optimization and ancillary services case study

Prokop Čech, *University of Jan Evangelista*

Power sector impacts of a simultaneous European heat pump rollout

Alexander Roth[1] (Speaker)

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Keywords: heat pumps, thermal energy storage, renewable energies, energy system modeling

Motivation

The paper addresses the need for decarbonization in the European building sector to meet the 2050 net-zero economy goal, focusing on the transition from fossil fuel heating systems to heat pumps. Despite heat pumps being efficient and crucial for decarbonization, their large-scale deployment presents challenges for the power sector, including increased electricity demand and peak loads. This study aims to understand these challenges by analyzing the effects of a simultaneous heat pump rollout across several central European countries. It assesses the impacts on peak heat demands, electricity generation needs, and the potential of thermal energy storage to mitigate these impacts.

Methods

The study utilizes an hourly-resolved capacity expansion model of the power sector to simulate the impacts of heat pump deployment on electricity demand and generation capacities. It covers heat demand for space and water heating in various building types across multiple countries, using heat pumps with and without thermal energy storage. The scenarios assume that 25% of total heat demand to be met by air-sourced heat pumps, with variations in thermal storage size. The analysis is based on data from several sources, including the When2Heat dataset for heat demand and ENTSO-E for renewable availability and electricity demand. Six weather years are modelled to ensure robustness against year-to-year variability. The analysis covers nine central-European countries.

Results

The findings reveal that a 25% coverage of building heat demand by air-sourced heat pumps significantly increases electricity demand, which requires additional generation capacities, optimally wind power. Even small thermal energy storage attached to heat pumps can dampen the need for additional firm generation capacity. The paper also highlights the misalignment between peak heat demands and residual load peaks, suggesting that heat pump deployment does not always worsen peak load challenges in the power sector. However, during certain weather conditions, especially extreme cold spells, the simultaneous demand for heating and high residual load can stress the power system, underscoring the importance of integrating thermal energy storage and renewable energy sources to manage the increased load. Due to the simultaneity of cold spells between countries, the analysis finds that electricity interconnection between does not help considerably to reduce additional firm capacity needs.

Leveraging smart meters to analyze price sensitivity under telescopic tariffs in India

Madhav Sharma[1] (Speaker), Anoop Singh[2]

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Keywords: Smart meters, demand response, price sensitivity, telescopic tariffs, clustering

Motivation

With India's smart meter deployment surpassing 9 million through the Revamped Distribution Sector Scheme (RDSS) launched in 2021, we have a unique opportunity to understand consumer response to tiered pricing, an essential step towards crafting effective demand response (DR) programs and energy-efficient tariff. Traditional models, often limited by assumptions of time-of-use price-driven behaviour, miss the intricacies of India's telescopic tariff design. These tariffs offer a unique lens to study how consumers react to average price increases by featuring consistent prices within tiers but jump at thresholds. By analysing these reactions, we gain insights into how consumers adapt their electricity use within telescopic tariffs, informing future DR strategies and tariff design.

Methods

This research employs a novel approach leveraging high-resolution smart meter data from 2,500 consumers across diverse locations over a one-year period. The data captures individual consumption patterns at 30-minute intervals. To analyze consumer response to price changes, we focus on consumption patterns around billing month ends (tier switches) to capture potential responses. Data clustering techniques segment consumers based on consumption profiles, revealing potential variations in elasticity between groups. Recognizing the influence of external factors, we integrate high-resolution weather data to isolate the true impact of price changes on consumer behaviour.

Results

Key findings include the identification of distinct consumer clusters exhibiting varying degrees of elasticity in response to the telescopic tariff, quantifying their impact on peak demand. Additionally, we expect to uncover valuable insights into temporal patterns, peak consumption periods, and other behavioural factors. Notably, this research demonstrates the effectiveness of clustering techniques in revealing nuanced relationships between tariff-pricing structures and consumer response. By analysing individual consumption patterns and their link to price sensitivity, we aim to provide valuable insights for energy providers and retailers to tailor their services and optimize demand forecasting.

Trade-offs between system cost and supply security in municipal energy system design: an analysis considering spatio-temporal disparities in the Value of Lost Load

Febin Kachirayil[1] (Speaker), David Huckebrink[2], Valentin Bertsch[3], Russell McKenna[4]

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Keywords: Value of Lost Load, Security of Electricity Supply, Urban energy systems, Demand reduction, Power interruption characteristics, Energy system optimization

Motivation

The Value of Lost Load is a key metric to assess the economic impact of power supply interruptions and establish supply security standards within the European Union. Current EU regulations recommend a single average value per country, overlooking regional and temporal differences in the value of electricity access. This study investigates the implications of this simplification by deriving county-level Value of Lost Load estimates at an hourly resolution for the residential sector in Germany through a production function approach. Load curtailment options at different costs are integrated into an urban energy system optimization model to evaluate their effects on system cost and reliability indicators. The findings demonstrate that load curtailment of 0.12% can yield outsized benefits and reduce system costs by 3%, primarily by decreasing storage requirements, thereby alleviating the pressure that is put on the municipal energy systems. Regions with cheaper load curtailment can obtain larger cost reductions, but only at the expense of a disproportionate decline in supply security. Introducing temporal detail on the other hand results in lower system costs while mitigating customer impacts through fewer curtailed hours and a notable shift towards night-time periods. Empowering customers through smart infrastructure deployment and tariff reforms to take energy conservation measures is crucial to maximize these benefits.

Residential battery flexibility: Spot optimization and ancillary services case study

Prokop Čech [1] (Speaker)

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Keywords: Spot optimization, Ancillary Services, Residential Batteries

Motivation

The accelerating integration of renewable energy sources (RES) coupled with a decline in reliance on fossil fuels has increased the demand for flexibility within the energy markets. Traditional approaches focusing solely on steering production are insufficient; there is a crucial need to adjust the demand side dynamically also. For such implementation effective incentives are necessary. The decentralized nature of flexibility on the low voltage level presents a significant untapped potential (higher than e.g. in the industry sector). However, numerous assets and diverse technologies present a challenge.

In the Czech Republic, batteries have been installed alongside photovoltaic systems in most cases. However, a majority of these installations lacks intelligent steering mechanisms, representing a missed opportunity for optimizing their potential and helping energy markets. Batteries in these settings offer a straightforward and easily implementable solution.

To illustrate the untapped value in steering residential batteries, we present a case study that demonstrates the optimization of these assets for spot market incentives and first test of residential low voltage batteries for provision of Ancillary Services (In cooperation with CEPS, the local TSO).

Methods

In our study, we engaged 20+ customers in a beta testing phase, dynamically steering their residential batteries via a cloud-based platform during 2023 and onwards. Each participant's setup varied, encompassing diverse parameters such as battery size, photovoltaic size, specific consumption patterns, parameter for amortization of the battery, and other unique factors. The aim of the algorithm was to reduce the cost as much as possible against spot prices given the specific constraints.

Utilizing past data, we present optimal solutions that showcase the potential savings achievable through spot market optimization on the pool of customers. Further, we show differences between the optimal solution (evaluated retrospectively) and actual steering (based on the prediction of the algorithm) metered in seconds granularity customer by customer.

Second part is focused on evaluation of tests conducted in collaboration with the Czech Transmission System Operator (CEPS). For the first time, we assessed the viability of low voltage batteries for automatic Frequency Restoration Reserve (aFRR) during three test runs conducted in December 2023. This marks a significant step forward in leveraging residential assets for ancillary services, contributing to the broader understanding of the role such batteries can play in grid stability and reliability.

Results

Our study is split to two parts, the maximum potential savings achievable through spot market optimization and the feasibility of using residential batteries for ancillary services, specifically aFRR. In the first section, we quantify the potential savings derived from our spot optimization. Using both in advance optimization and actually metered data as well as fictional rerun based on metered data. We quantify the economic benefits attainable by dynamically steering residential batteries. We show real-life scenarios, identifying challenges and areas where real time optimization with uncertain predictions of input parameters encounters difficulties. Additionally, we examine the influence of diverse parameters on the maximum achievable optimization.
The second part of our results focuses on the test runs conducted for ancillary services. Our analysis demonstrates the viability of utilizing residential batteries for these services, surpassing the stipulated parameters for aFRR. However, we also discuss the drawbacks encountered during the test runs. This includes challenges related to real-time implementation, system response, and other practical considerations that must be addressed for the successful integration of residential batteries into the ancillary services framework.

Session 14:05 – 15:35
Reviewing nuclear power

Room: HSZ/301/U
Chair: Felix Fliegner

Nuclear fusion: An institutional economic analysis of a complex system good

Fanny Böse, *Federal Office for the Safety of Nuclear Waste Management (BASE)*

The economic efficiency of non-light water reactors and their non-electrical applications in decarbonized energy systems

Alexander Wimmers, *University of Technology Berlin*

The nuclear paradox in energy scenarios: Exploring nuclear projections and reality

Christian von Hirschhausen, *University of Technology Berlin*

The effects of nuclear power plant closures in Germany 2021-2023 on network flows and RE-dispatch – Update of earlier ELMOD modeling results

Enno Wiebrow, *University of Technology Berlin*

Nuclear fusion: An institutional economic analysis of a complex system good

Stefanie Böhnlein[1], Efe Bölme[2], Christian von Hirschhausen[3], Alexander Wimmers[4], Fanny Böse[5] (Speaker)

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Keywords: nuclear fusion, system good, history, decarbonization, organizational models

Motivation

Recent developments in nuclear fusion such as the experiments based on laser-driven nuclear fusion at the National Ignition Facility of the Lawrence-Livermore National Laboratory, have reignited enthusiasm in nuclear fusion as a potential solution for seemingly limitless low-carbon energy production (Chatzis and Barbarino 2021). However, the development of nuclear fusion has a long history, compromises different technical approaches such as magnetic confinement (MCF) or inertial confinement (ICF) (Nuttall 2022), a variation of organizational models for reactor development and its potential commercialization. Thus, in order to assess potential future developments and investments into nuclear fusion a historic as well as systematic perspective of a complex system good is required.

Methods

In this paper, we discuss the long-term innovation dynamics of nuclear fusion, with a special focus on the interaction between industry, research, and (public and private) funding organization. Even the recent enthusiasm vis-à-vis nuclear fusion for seemingly limitless low-carbon energy production, (Weir 2023)) (Chatzis and Barbarino 2021), the objective of this paper is to provide a methodology and first empirical evidence on how the chain of invention, innovation, and diffusion can emerge, or – in our case – does not emerge. Additionally, we combine the system good analysis developed by Beckers et al. (2012), i.e.

- the analysis of the technical system ("supply") and the demand for different goods and services (electricity, research, weaponry, etc.),
- actors and roles in this process, and
- different governance structures at work (we adopt a positive approach).

In this framework, a system good refers to the provision of complex goods or services in different sectors and with a wide array of up- and down-stream processes. In a first step, the technical system, i.e. the central processes and assets are described. These tasks are attributed to various roles from which a "model of roles" is defined that shows necessary areas of coordination. Such a system perspective can reveal which steps are critical to provide energy from fusion power as well as other possible applications. Furthermore, challenges and opportunities of different institutional approaches can be identified.

Results

Results show that similar to nuclear fission the development of military weapons, in particular the fission bomb, preceded other potential applications such as commercial energy generation. Since then, different technical approaches for nuclear fusion were developed, However, the industry has not succeeded even the first step of the ladder, invention, i.e. generate electricity (at reasonable prices), and it is very unlikely that this will change in the next decades. However, there are benefits from fundamental research, e.g. in material science, laser technology, and health, that R&D policies should focus upon. The challenges associated with organizational models include significant bureaucratic hurdles, technological complexities, and financing schemes that face uncertainties. Such hurdles have led to substantial coordination efforts and transaction costs, which in turn result in delay of project realization. The use of by products and a more flexible choice of suppliers indicate potential advantages. However, it still has to be shown which technological approach is most suited for commercial electricity generation (at reasonable prices), if ever realized. In contrast, decarbonization requires urgency, and thus the deployment of available and cost-competitive energy. Thus, the paper concludes that the "dream" of nuclear fusion as an unlimited source of electricity should switch to more research-oriented questions on which kinds of fundamental research should receive public support, and under which governance structures.

The economic efficiency of non-light water reactors and their non-electrical applications in decarbonized energy systems

Alexander Wimmers[1] (Speaker), Leonard Göke[2], Fanny Böse[3], Björn Steigerwald[4], Christian von Hirschhausen[5]

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

Motivation

Previous research has shown that cost projections for high-capacity light-water reactors are overly optimistic and underly a high degree of variance, and that overnight construction costs (OCC) must be substantially reduced to be considered by a cost-optimizing energy system model for a decarbonized European energy system (Göke, Wimmers, and von Hirschhausen 2023). However, so-called "advanced" non-light water reactors, such as sodium-cooled fast reactors (SFR) and so-called small modular reactors (SMR) are envisioned in future energy systems dominated by fluctuating renewable energy sources by providing non-electrical use cases such as heat, either district or for industrial purposes (Brown 2022), hydrogen production (Nuttall and Bakenne 2020), seawater desalination (Ingersoll et al. 2014) or load following (Jenkins et al. 2018). In order to succeed in a decarbonized energy system, such reactor concepts must be 1) affordable, 2) economically competitive, 3) socially acceptable, and 4) commercially available (Committee on Laying the Foundation for New and Advanced Nuclear Reactors in the United States et al. 2023). While none of the proposed reactor concepts are currently commercially available, ongoing development efforts might lead to availability of some non-light water concepts in the coming decades.

Methods

To assess this, we conduct three methodological steps. The first step comprises an in-depth literature analysis into potential non-electrical applications and potentially suited reactor concepts. This includes descriptions of historic applications and a qualitative assessment of future applicability. The second step is an analysis of currently available data on costs for non-light water reactor concepts. Data is divided into "first-of-a-kind" (FOAK) and "n-th-of-a-kind" (NOAK) data. Cost data is normalized following (Abou-Jaoude et al. 2023). The third step is the integration of these cost projections into a comprehensive techno-economic model to assess the applicability of reactor concepts in a future decarbonized energy system (Göke 2021a; 2021b). The model application includes a total of four stylized reactor concepts that are each able to provide a certain form of heat in combination with standard electricity production. "Generation III(+)" reactors produce district heat, SMRs produce low process heat (≤ 150°C), SFRs produce medium process heat (300-500°C), while HTRs produce medium and high process heat (>750°C).

Results

Results of the first part of the analysis indicate that while there have been several use cases for non-electrical applications from nuclear reactors, they are limited to certain geographical regions and individual reactors mainly due to technological constraints regarding the transportation of heat and the non-availability of non-light water reactors. The cost analysis yields a wide range of cost projections for OCC. Cost projections range back to 1978 and differ strongly depending on the type of reactor. However, cost data shows that expectations of currently unavailable reactor concepts are low or sometimes even on the level of already unrealistic projections for high-capacity light-water reactors (Göke, Wimmers, and von Hirschhausen 2023). First results of the model application show that at mean NOAK OCC and seven years construction time for all four available reactor concepts, only HTRs are built in a future decarbonized energy system. These reactors provide a total of 2338.3 TWh of energy, divided equally between high temperature process heat and electricity. Only when OCC are further reduced, are other nuclear reactors included. At FOAK costs, no nuclear reactor is built. Further scenarios and in-depth analyses are currently under development. Our current results indicate that first, many so-called "advanced" reactor technology cost projections are similarly over-optimistic as projections for current light water reactors, and that even if reactor technologies became available at such proposed cost levels in the coming decades, they would compete with cheaper renewable energy and storage technologies that are already available today. Consequently, discussions on the future role of nuclear power should acknowledge the current unavailability and inexperience regarding the operation of non-light water reactor concepts, discrepancies in cost assumptions, and the actual potential cost-efficient role of nuclear in a future decarbonized energy system.

The nuclear paradox in energy scenarios: Exploring nuclear projections and reality

Christian von Hirschhausen[1] (Speaker), Fanny Böse[2], Alexanders Wimmers[3], Björn Steigerwald[4]

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Keywords: nuclear power, energy scenarios, paradox, reactor technologies, economics

Motivation

The paper identifies a paradox in nuclear energy projections such as collected in IPCC database. The average scenarios in the IPCC 6th Assessment Report anticipate a significant increase in nuclear electricity production by 2050 and 2100. Findings that recently were used to pledge the tripling in nuclear capacity at COP 28 supported by various countries.

Methods

The paper is structured as follows: firstly it explores IPCC database scenarios (see Figure 1) regarding nuclear`s role as such. Such growth expectations are then contrasted with historic projections from past studies such as (Häfele 1981) from IIASA in order to show reoccurring patterns of strong-growth expectations, but which have not materialized. The nuclear paradox is explained including techno-economic key parameters. Finally, the implications drawn from this analysis serve to inform future energy scenario modeling endeavors.

Results

Some energy scenarios projections stand in deep contrast historic and actual development, which is characterized by an industry in decline, with lacking economic competitiveness in both light-water and non-light water reactors. Light-water reactors, reaching their peak in the 1970s and 80s, face economic challenges and delays, with lacking competitiveness against other energy sources. So called “small modular” reactors (SMRs) suffer from similar issues and require mass production for economic viability. Additionally, the development and commercialization of non-light water reactors, such as so-called breeder reactors, have been slow. Instead, a reoccurring overestimation of nuclear power for electricity generation can be identified which already began in the 1950s as the "dream of the plutonium economy" had emerged. Such hopes rooted in the expectation of efficient energy supply through breeding in metal-cooled reactors. However, the realization of this dream has not materialized. Current efforts in the light of decarbonization seem to recall the "breeder" vision, but its status quo ultimately challenges the output of IPCC scenarios. Thus, paper calls for the need to re-examine socio-technical assumptions in the scenarios, in order to derive more realistic assessments of nuclear power's role in decarbonization scenarios.

The effects of nuclear power plant closures in Germany 2021-2023 on network flows and RE-dispatch – Update of earlier ELMOD modeling results

Enno Wiebrow [1] (Speaker), Lukas Barner[2], Christian von Hirschhausen[3], Kristin Dietrich[4], Mario Kendziorski[5]

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Keywords: electricity market modeling, optimization, nuclear energy, nuclear phase-out, grid stability

Motivation

The decommissioning of the last six nuclear power plants (NPPs) in Germany between December 2021 and April 15, 2023, marked a historic step. The energy crisis raised significant concerns over the reliability and stability of Germany's electricity network, primarily due to the potential scarcity of natural gas supplies and the implications of shutting down nuclear facilities. These concerns underscore the importance of evaluating the repercussions of such energy policy decisions, particularly in times of geopolitical and economic uncertainty. This paper aims to conduct a model-based ex-post analysis to scrutinize the effects of the NPP shutdowns on Germany's power transmission network, exploring the impacts on electricity imports and CO2 emissions.

Methods

Employing an enhanced version of the electricity market-network model, this study builds upon the foundational aspects of POMATO (with its emphasis on network re-dispatch) and Elmod (centered on energy economics). The methodology involves an ex-post evaluation of the operational impacts on the transmission network, incorporating scenarios of increased electricity imports and changes in CO2 emissions. The analysis is grounded in a robust validation process utilizing publicly available market data and historical generation time series. This approach enables a detailed examination of the immediate and medium-term effects of the NPP shutdowns on Germany's electricity system, offering insights into the operational feasibility and environmental implications.

Results

Model calculations are still ongoing. However, current preliminary results suggest that maintaining a stable electricity network operation without NPPs was feasible, albeit with certain short-term trade-offs. The loss of generation capacity previously provided by the nuclear plants was temporarily compensated for by heightened electricity imports, some newbuilds of renewables, and an uptick in CO2 emissions. This compensation mechanism highlights the resilience of Germany's electricity system, while also pointing to the challenges of ensuring supply security and environmental sustainability. The model results underscore the necessity of strategic planning and investment in renewable energy sources and grid infrastructure to mitigate the environmental impact and ensure the long-term stability of the energy system post-nuclear phase-out.

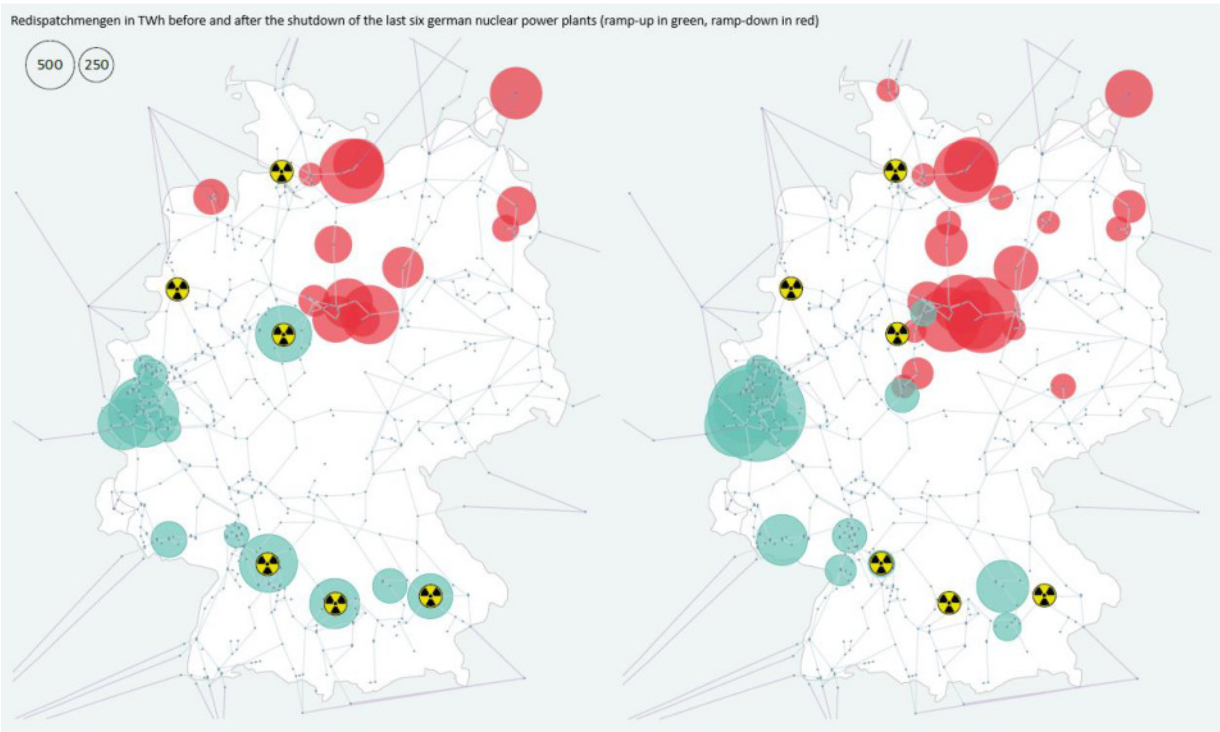

Figure 1

Session 14:05 – 15:35
District heating transition

Room: HSZ/304/Z
Chair: Hendrik Scharf

What role do CHP plants and electric heat generators play in decarbonised district heating networks?
Matthias Koch, *Öko-Institut*

Flexibility provision in 5th gen district heating systems
Annette Steingrube, *Fraunhofer ISE*

A case study on long-term investment planning for the decarbonization of Western Europe's most complex district heating network
Stephanie Riedmüller*, Zuse Institute Berlin*

Towards carbon neutrality: Integrated investment and operational optimization for district heating transformation - A case study of Dresden in Germany
Felix Bumann, *SachsenEnergie AG*

What role do CHP plants and electric heat generators play in decarbonised district heating networks?

Matthias Koch[1] (Speaker), Christof Timpe[2], Susanne Krieger[3], Max Fette[4], Leander Kimmer[5]

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Keywords: district heating networks, CHP plants, electric heat generators, decarbonisation, sector coupling

Motivation

The generation of district heating in Germany is still largely based on fossil fuels and the use of CHP plants. In order to decarbonise district heating generation, fossil fuels must be replaced by renewable energies. Large scale heat pumps and electrode heating boilers powered by renewable electricity are available for this purpose, as are biomass, waste or hydrogen-fuelled heating plants and CHP plants. Depending on regional availability, geothermal energy, waste heat and solar thermal energy can also be used.

What role CHP plants will still play in decarbonised district heating networks and how they, together with the electrical heat generators, will interact with the electricity system is still an open research question. Depending on the situation in the electricity system in combination with the heat demand in the heating networks, electric heat generators and CHP plants can increase or reduce load peaks or capacity deficits in the electricity system. Multivalent generation parks in district heating networks also represent a flexibility option for the electricity system.

These research questions are being investigated in the Kopernikus project ENSURE with the help of a model-based scenario analysis. The ENSURE scenario D (focus on decentralized energy transition) and scenario B (focus on Paris-compatible reduction path) are considered as scenarios for the year 2030 as well as scenario B (focus on direct electrification) from the German grid development plan 2037/2045 and ENSURE scenario B (focus on hydrogen and e-fuels) for the year 2045.

The ENSURE project is funded by the Federal Ministry of Education and Research.

Methods

In a first step, six typified district heating networks are defined, which differ in terms of various criteria. In the area of district heating demand, this is the proportion of building heat and process heat. On the one hand, this composition affects the demand profile in hourly resolution and, on the other hand, indirectly determines the technology options for the plant fleet (especially for the industrial heating network).

As a result, a local district heating network with a demand of 100% building heat, four large big city networks with a demand of 85% building heat and 15% process heat and an industrial network with a demand of 100% process heat are defined.

The respective plant parks in the six types of district heating networks differ first of all in terms of the amount of possible continuous generation from geothermal energy and waste heat. Coal-fired power plants (only for ENSURE scenario D 2030), waste incineration plants and biomass plants are then allocated to selected network types. Two otherwise identically parameterized metropolitan district heating networks also differ in terms of the proportion of electric heat generators and gas-based heat generators (focus on electricity versus focus on natural gas / hydrogen).

In a second step these six district heating networks will then be integrated into the European electricity market model PowerFlex for Germany. The PowerFlex model determines the minimum-cost use of generation plants, storage facilities and demand-side flexibility options in order to cover the demand for electricity, balancing power and district heating on an hourly basis. The marginal costs of the electrical heat generators in the district heating networks arise during the simultaneous dispatch decision and vary as a result per hour and district heating network.

In a third step, a sensitivity analysis is carried out in which all CHP systems are replaced by uncoupled electricity and heat generation systems using the same fuel.

Results

To analyze the interactions between the electricity system and the district heating networks, various key figures are formed, for example load and generation profiles, maximum load of electric heating technologies, full load hours of the individual plant fleet, electricity prices, costs of district heating supply or specific CO2-intensity of electricity and district heating.

The results of step 1 are exemplary shown for the ENSURE scenario B 2045 in figure 1 (plant fleet per energy carrier), figure 2 (plant fleet per technology class) and figure 3 (heat demand profiles including network losses).

Steps 2 and 3 are currently in progress and will be completed in the next few weeks. Initial results show that CHP systems still play an important role in the metropolitan network 3 and in the industrial heating network. In contrast, electric heat generators dominate especially in the small scale loacal heating network and in the metropolitan district heating network 2 and 4. CHP systems only run in these networks during times when electricity prices are high. In addition, it becomes clear that a high proportion of hydrogen makes district heating supply more expensive.

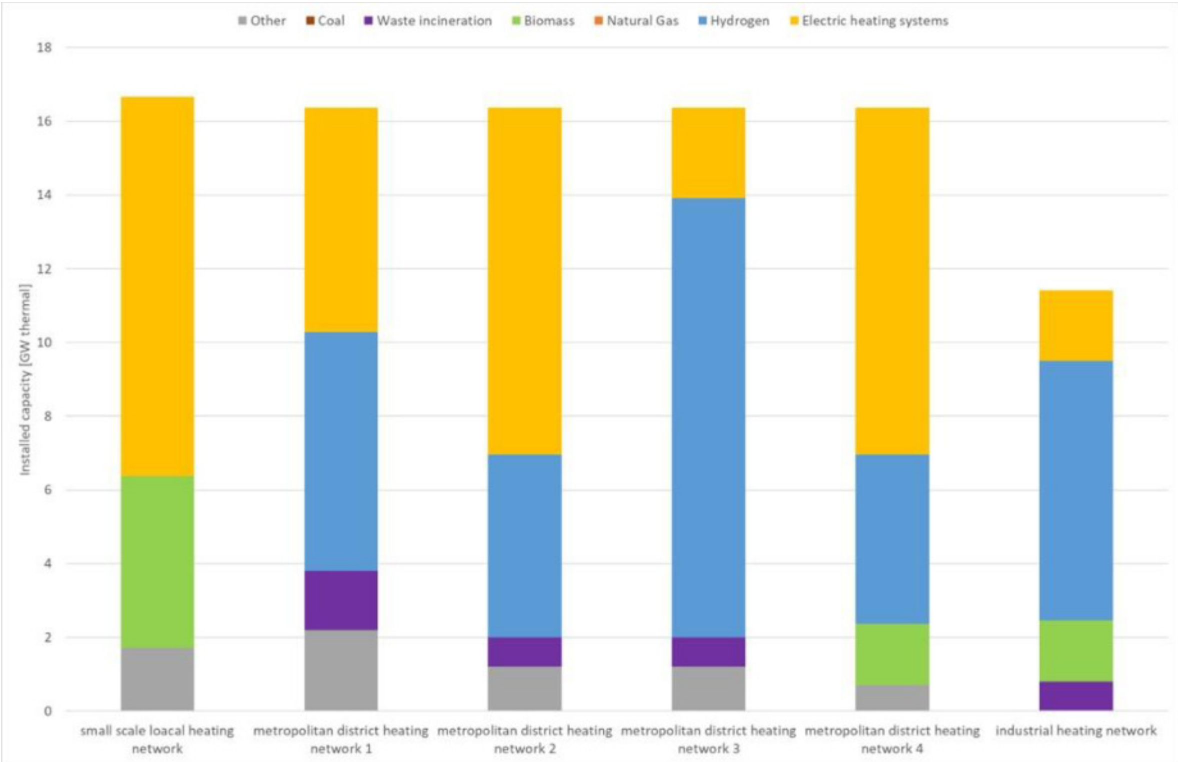


Figure 1

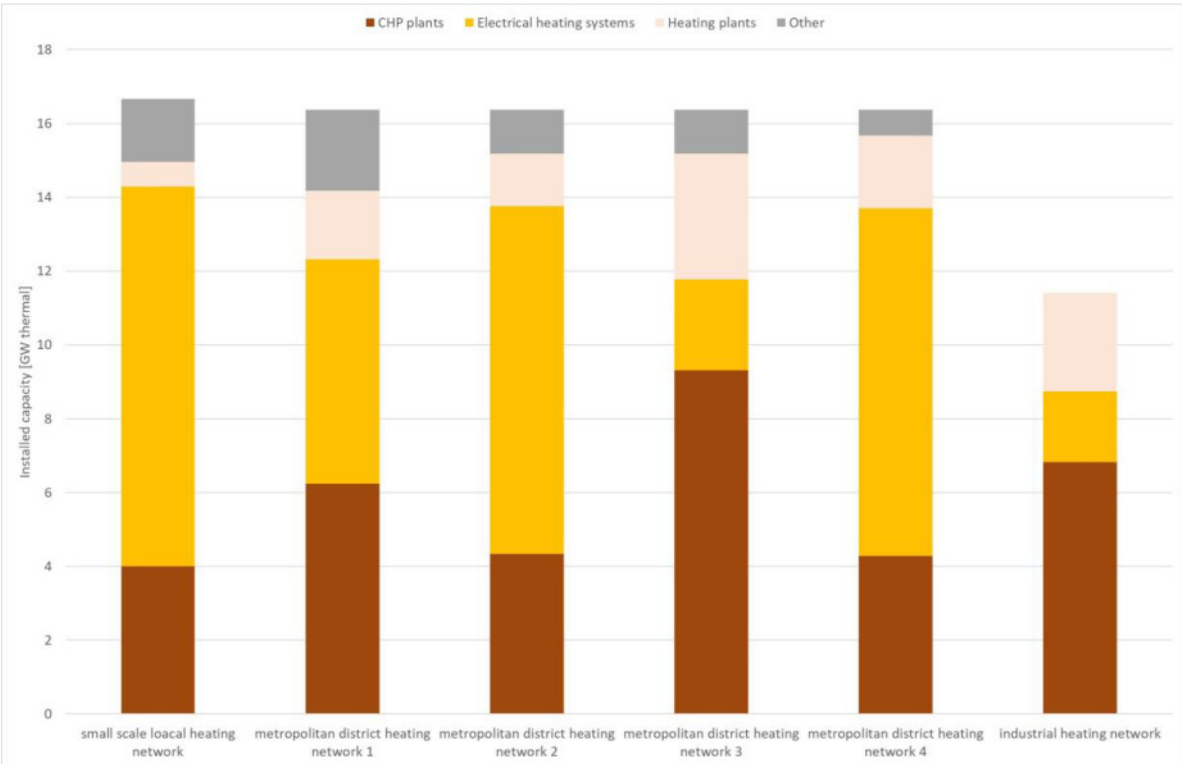
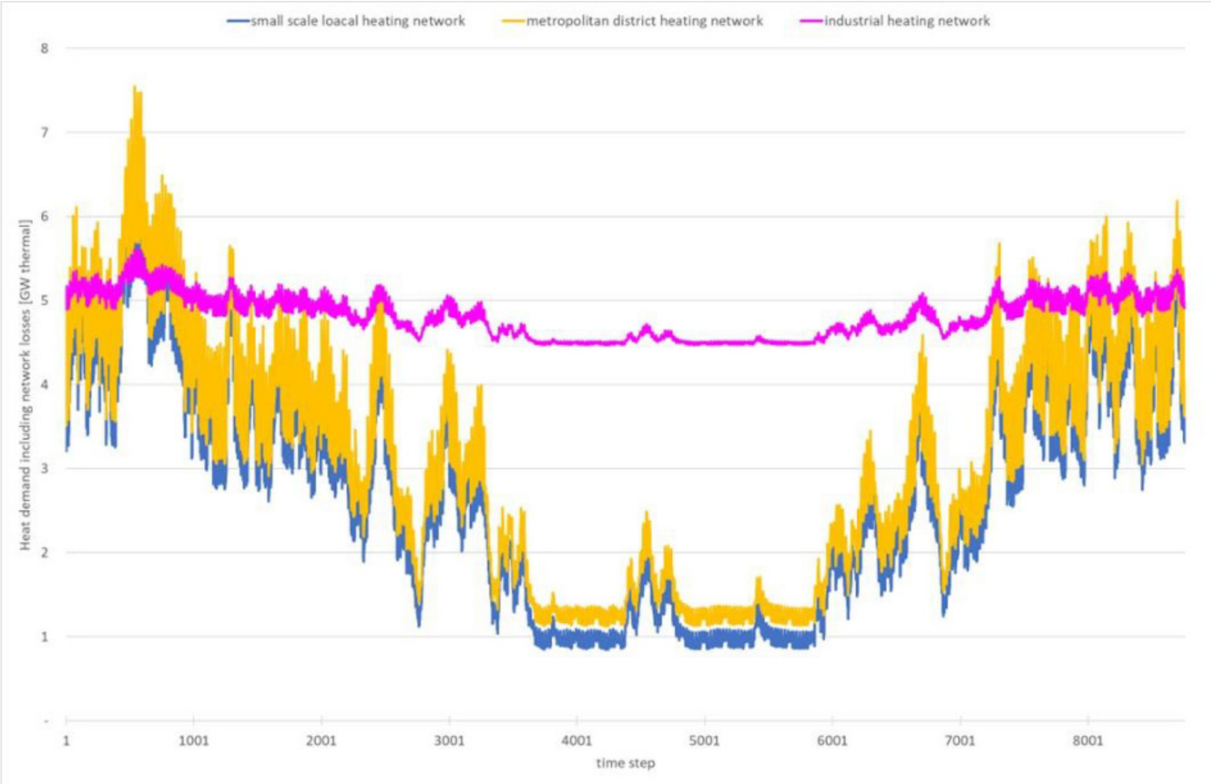


Figure 2


small scale loacal heating network
metropolitan district heating network
industrial heating network
Heat demand including network losses [GW thermal]
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7
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1001
2001
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4001
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7001
8001
time step

Figure 3

Flexibility provision in 5th gen district heating systems

Erik Fröhlich[1], Annette Steingrube[2] (Speaker)

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Keywords: flexibilities, 5th gen district heating, sector coupling, energy communities, energy system modelling, decentral energy systems, power grid services, control reserve

Motivation

To reach climate neutrality in 2045 in Germany, a major transformation is needed to decarbonize heating systems in the building sector. Next to decentral electrical heating systems, district heating networks are meant to play a vital role in that transformation [1]. With district heating systems evolving and buildings' energy efficiency improving, system temperatures go down, with 5th gen heating networks allowing flow temperatures of e.g. 20°C or less, boosting efficiency and enabling the use of e.g. low temperature waste heat. In such systems, heating and cooling demands can be supplied and balanced out at the same time, typically incorporating heat pumps and compression chillers. These technologies provide the possibility of sector coupling, together with storages they allow flexible operation, according to the needs of a power grid dominated by renewable generation. Thus, they are well suited for the integration in future renewable energy systems. However, systems of this type have high investment costs and the cost competitiveness of district heating networks might not always be given, depending on local factors. Establishing business models using that flexibility can play a crucial role in decreasing the overall costs of these systems.

[1] A. Burkhardt and M. Blesl, ""Ariadne-Analyse: Wandel der Fernwärme im Kontext des Kohleausstiegs und der aktuellen Gaskrise,"" 2023.

Methods

The communal energy system modelling tool KomMod [2] is used to represent the energy system of an example district in Herne, Germany, incorporating a 5th gen district heating network supplying a quarter characterized by seasonal heating demand and all-year cooling demand. KomMod is a linear, cost-optimizing, techno-economic energy system model. It yields a cost optimal energy system including the installed capacities and operation in hourly resolution of all technologies. Thermal networks are represented in the form of energy differences, which are solved on different temperature levels. The considered district consists of various multistorybuildings with different demand patterns. The heart of its energy system is the heating network with a hot water pipe with 22°C and a cold water pipe with 12 °C. Heating demands are supplied on different temperature levels by decentral heat pumps, cooling demands are supplied passively by the cold water pipe or compression chillers. In this study different possibilities of providing flexibilities are assessed, namely the reduction of peak power and the provision of balancing services. As power grids have to be designed for peak loads, the reduction of peak power is of great interest to the grid providers. Balancing services are needed to maintain a stable frequency in power grids, control reserves are retained to be activated in case of frequency deviation. For the representation of offering flexibility by participating in the control reserve energy market, a two-stage optimization approach is developed. The prices for control reserve can be quite volatile and their future development remains uncertain, as renewable generation forecasts improve and more flexible generators and consumers emerge [3, 4]. Thus, instead of applying current price levels, a price sensitivity analysis is carried out, yielding the critical points at which system behavior and design is altered by the optimizer to provide flexibilities.

Results

The results show that providing balancing services with the described system is economically attractive, even for low payment levels of 5% to 25% of current prices. Without changing the system design, which is optimized for operation without flexibility provision, the costs of the energy system can be reduced by only adjusting its operation. By increasing thermal storage capacities, the amount of reserve energy delivered can be significantly increased and costs of heating are further reduced. This means, that overdimensioning of thermal storages in the planning process of 5th gen district heating systems can be an option to reduce system costs when flexibilities are offered. However, flexibilities can only be offered when there is a demand for heating or cooling. Due to the all-year cooling demand flexibilities can be offered all year long, in a system without these cooling demands, flexibilities could only be offered during heating season. This would reduce the economic appeal of building larger storages for the provision of balancing services. However, it can still present an attractive business model. Reducing peak load is less attractive in the considered system, as the potential is limited with electricity demands of heat generation making up only a minor part of the electrical load.

[2] J.-B. Eggers, ""Das kommunale Energiesystemmodell KomMod,"" Dissertation, Berlin, Fraunhofer-Institut für Solare Energiesysteme, and Fraunhofer IRB-Verlag, Technische Universität.
[3] Institute of Electrical and Electronics Engineers, 2020 17th International Conference on the European Energy Market (EEM). Piscataway, NJ: IEEE, 2020. [Online]. Available: https://ieeexplore.ieee.org/servlet/opac?punumber=9217568

[4] B. Blat Belmonte, P. Mouratidis, G. Franke, and S. Rinderknecht, ""Developments in the cost of grid balancing services and the design of the European balancing market,"" Energy Reports, vol. 10, pp. 910–931, 2023, doi: 10.1016/j.egyr.2023.07.045.

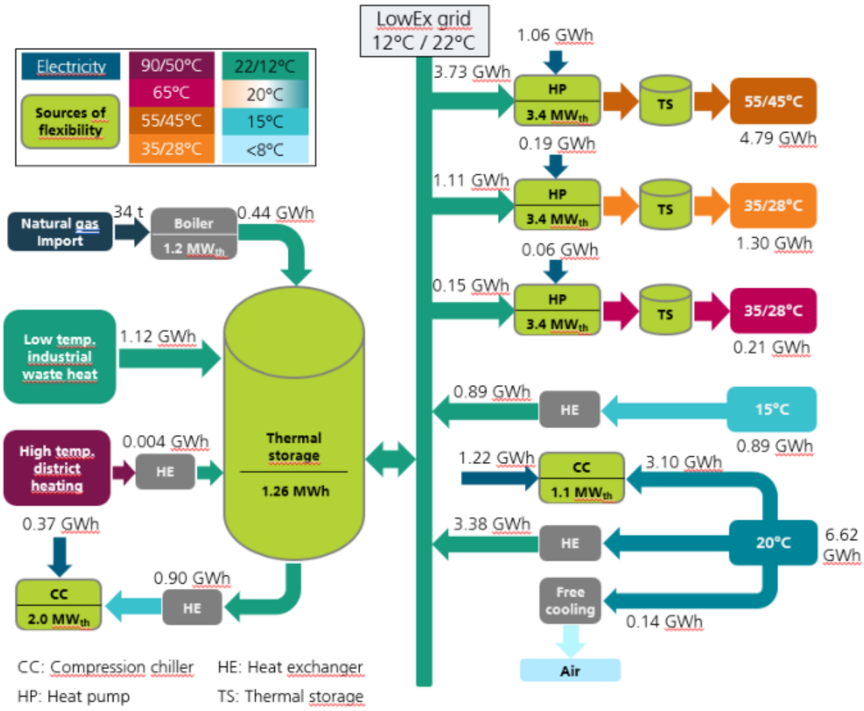

Figure 1: Schematic representation of the considered system including installed capacities and energy flows in planned operation without offering flexibilities. Possible sources of flexibility are marked green.

Figure 1

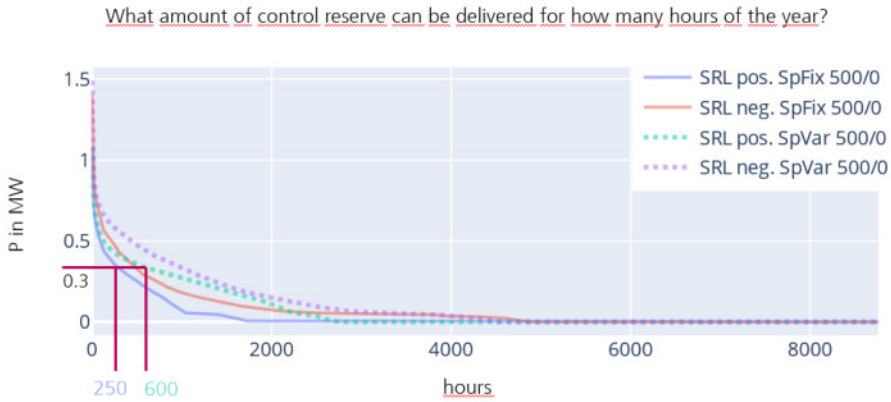

Figure 2: Results showing two different calculation variants for the provision of control reserve. At comparably low revenue levels of control reserve of 500€/MWh pos. and 0€/MWh neg. it is economically attractive to increase thermal storage capacities (+300%) to double the offered flexibility (SpFix: fixed thermal storages, SpVar: optimized storage capacities)

Figure 2

A case study on long-term investment planning for the decarbonization of Western Europe's most complex district heating network

Stephanie Riedmüller[1] (Speaker), Janina Zittel[2], Fabian Rivetta[3]

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Keywords: District Heating, Multi-Objective Optimization, Investment Planning, Mixed Integer Programming, Decarbonization

Motivation

The goal to achieve a sustainable and environmentally conscious energy system has led to an intensified focus on decarbonization. As a pivotal component of overall energy consumption, heating systems play a critical role in shaping the trajectory towards a low-carbon future. This role is particularly pronounced given the relatively modest contribution of renewable energies to heat production (17%) compared to their more substantial role in electricity generation (50%) within Germany. Therefore, the transformation of the heating sector became recently a prominent part towards that goal, specifically emphasizing district heating networks in urban and suburban areas. Through a case study, we aim to contribute valuable insights to the ongoing discourse on achieving decarbonization targets in the heating sector in line with reasonable economic decisions. Emphasizing the need for transformative measures, the study explores different transformation pathways to address the environmental impact of heating systems.

We present a case study on investment planning in the district heating network of Berlin, Germany, the most complex grid in Western Europe. This investment planning includes the promotion of renewable energy through optimizing investment planning beyond economic efficiency to minimize CO2 emissions. Hereby, investment candidates include large heat pumps for Power-to-Heat and combined heat and power plants (CHP). To that end, an a-posteriori optimization with a lexicographic algorithm is used to determine a solution catalog with optimal trade-offs between cost and environmental targets along the Pareto front. We investigate how the different objectives affect the transformation paths and distinguish robust from target-dependent investments.

Methods

The presented model incorporates the Verbundnetz of Berlin, denoting the main interconnected grid. The initial topology encompasses power plants situated at ten substations. Within this framework, the heat-producing power plants exhibit a distribution of approximately 43% capacity from heating stations and 57% from CHP plants and are predominantly fueled by gas (75%) and coal (19%). In addition to power generation facilities, the model incorporates various storage units, fuel conversion processes, as well as integration with relevant markets, including potential heat import and export. Beyond the initial grid topology, the model encompasses 38 strategically selected potential investment decisions. These include 11 additional heating stations, five storage units, three heat pumps of varying capacities (up to 120 MW), four electrical heaters (up to 320 MW), a solar thermal facility, five CHP plants, and nine gas turbines or upgrades to existing gas turbines. The model extends its scope over a planning period of 25 years (2020–2045) and integrates long-term investment planning into a unit commitment problem. This holistic approach, incorporating both investment and operational decisions, is necessary to achieve realistic CO2-emission reductions.

The problem is formulated as a mixed-integer linear problem, with two objectives centered on minimizing costs and CO2-emissions. The bi-objective optimization is executed through a lexicographic algorithm with minimizing costs as primary objective, followed by a secondary minimization of CO2-emissions. While minimizing CO2-emissions, the optimal cost value is relaxed within a specified cost tolerance gap. In this case study, scenarios are systematically explored by considering varying tolerance gaps in increments of 5%, ranging up to 30% of the cost optimum, where the cost optimum is computed within a 1% relaxation and 2% MIP-gap. The main target is to analyze trade-offs between costs and CO2-emissions.

Results

The adaption of the cost tolerance gap yields a notable impact on CO2-emissions. The rate of CO2-savings is particularly rapid for the near optimal solution w.r.t. costs, gradually diminishing as the tolerance gap widens. Specifically, a 5% increase in costs results in a substantial 10% reduction in CO2-emissions, while a 30% increase in costs corresponds to a 33% decrease in CO2-emissions.

Among the pool of potential investments, a subset of 27 investments consistently remains unselected, while 10 investments emerge as fixed choices (robust investment decisions). These include an additional heating station, four new CHP plants, and five gas turbines or their upgrades. Three distinctive transformation pathways have been identified: The cost-optimal pathway comprises the robust investment decisions with an additional gas turbine. Omitting the previous gas turbine can achieve a CO2-emission reduction of 22-26%. Introducing an electrical heater result in a CO2-emission reduction of 30-33 %.

Notice that the reduction of CO2-emissions is not solely dependent on the selection of investments but also linked to the operation of the power plants. Consequently, identical investment portfolios may yield distinct CO2-emission outcomes. In fact, the three scenarios characterized by a cost tolerance gap up to 10% do not differ in investment decisions but show a CO_2-emission reduction of up to 17%.

In conclusion, reasonably relaxing the optimal cost scenario can significantly reduce CO_2 emissions. The findings of this study underline the interaction of investment and operational decisions. Furthermore, electrical heaters become relevant in scenarios characterized by substantial cost variations. By investigating trade-offs within relevant parameter ranges, multi-objective optimization can provide a nuanced understanding and empowers stakeholders to make informed and sustainable investment decisions in long-term energy portfolio planning.

Towards carbon neutrality: Integrated investment and operational optimization for district heating transformation - A case study of Dresden in Germany

Felix Bumann[1] (Speaker), Carl-Phillipp Anke[2], Peter Stange[3]

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[3]*TU Dresden, peter.stange@tu-dresden.de*

Keywords: Optimization, District Heating, Case Study, Transformation, Modeling, Energy System

Motivation

Much research has been done in recent years on the transformation of the electricity sector. As renewable electricity generation continues to grow, the heating sector is becoming increasingly important. In Germany, the heating sector accounts for more than half of total final energy demand. Domestic heating and hot water account for around two thirds of total heat consumption. The expansion of district heating is part of the solution to decarbonize this sector. Currently, most district heating systems rely heavily on fossil fuels. Achieving carbon neutrality targets will therefore require significant investment in new technologies. Planning the transition from existing systems to these increasingly integrated and complex energy systems is a very complex process. An easy-to-use optimization tool has been developed to identify cost-optimal transformation paths (scenario sharp) and to analyze techno-economic interactions between different technologies and external factors. The model has been applied in a case study of Dresden.

Methods

The transformation was modelled using bottom-up energy system modelling, operating on one-hour time increments. An integrated optimization of investment and operating costs of heat production was performed, considering the path dependencies of the investments at different time steps and identifies the global optimum for the transformation. The model possesses perfect foresight of the expected heat demand, flow temperatures and prices of different energy sources. The technical and economic parameters of existing and potential heat generators, such as heat pumps, heat storage, CHP, boilers, and waste heat sources are also predefined. The model is based on the open-source Python package 'flixOpt', developed at the Chair of Building Energy and Heat Supply at the TU Dresden.

In the case study of the district heating system of Dresden, the transformation to 2045 was mapped over four base years to reduce complexity. Uncertainties in forecasts are accounted for by considering several scenarios. These scenarios also differ in the target year for achieving climate neutrality to evaluate the economic impacts of an early transition, as well as the purely economic pressure to transform. The study also considered the “German federal support program for efficient heating networks” (BEW). Energy taxes and surcharges remained unchanged in subsequent years and hydrogen is subject to the same taxes as natural gas. The model was successfully validated by comparing results to historic dispatch and a commercial dispatch optimization tool.

Results

Volatile electricity prices heavily influence combined heat and power (CHP) and heat pump (HP) dispatch. Heat storage becomes increasingly vital for district heating systems, enabling price fluctuation exploitation through CHP and HP. With low-energy price periods becoming more frequent, especially in 2035 and beyond, the profitability of heat pumps rises, leading to a rapid increase in installed power. With the growing time windows of low electricity prices, the needed storage power for efficient dispatch of heat pumps in summer decreases. In contrast, the daily intervals of high electricity prices for profitable CHP operation shorten, especially in the summer. Thus, new CHP units need to be flexible and operated along heat storage with high power and capacity to utilize excess heat efficiently. Since the dispatch of heat pumps operates inversely to that of CHP, they compete during periods of low heat demand. New natural gas-fired CHP is limited by high investment costs, while boilers are used as an interim solution. Hydrogen is the final step towards carbon neutrality and hydrogen-based CHP isn't economically viable before 2045. Annual consumption and peak demand of hydrogen are many times lower compared to natural gas in 2021.

Waste heat usage is profitable, but declines due to price dynamics increasingly favoring CHP and HP.

The "German Federal Support Program for Efficient Heating Networks" (BEW) has a significant impact on investment decisions by promoting the use of heat pumps, storage, and waste heat. A similar program for hydrogen-powered cogeneration will change the optimal transformation path. Under the current electricity taxes and surcharges, electrode boilers are not economic.

Under these constraints, annual heating costs show minimal variation between scenarios. However, there are significant differences in CO2-Emissions, suggesting that the target year for achieving carbon neutrality may need to be reassessed.

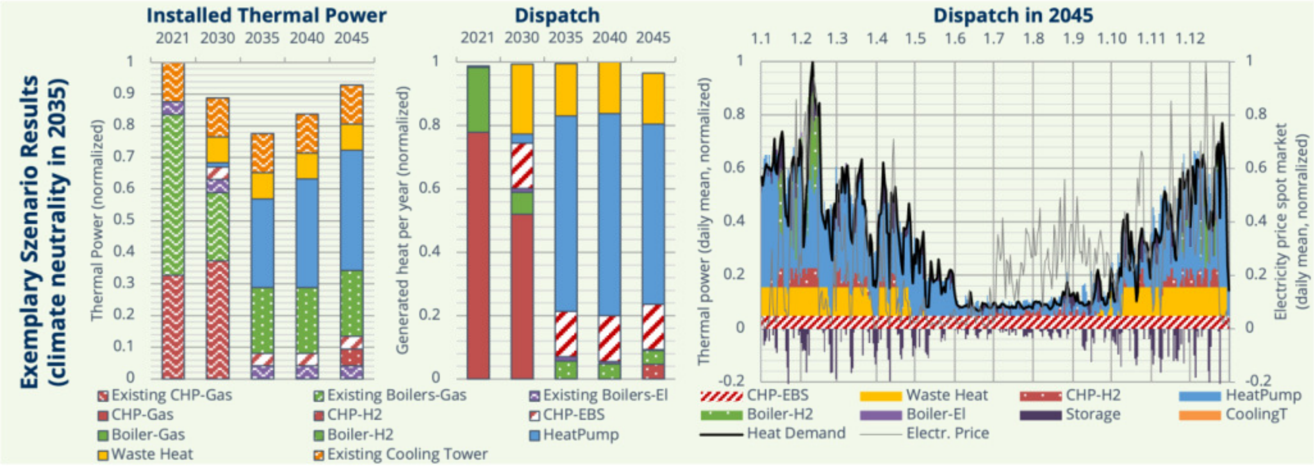
Exemplary Szenario Results (climate neutrality in 2035)
Installed Thermal Power
Dispatch
Dispatch in 2045
Thermal Power (normalized)
Generated heat per year (normalized)
Thermal power (daily mean, normalized)
Electricity price spot market (daily mean, nomralized)
Existing CHP-Gas
Existing Boilers-Gas
Existing Boilers-El
CHP-Gas
CHP-H2
CHP-EBS
Boiler-Gas
Boiler-H2
HeatPump
Waste Heat
Existing Cooling Tower
CHP-EBS
Waste Heat
CHP-H2
HeatPump
Boiler-H2
Boiler-El
Storage
CoolingT
Heat Demand
Electr. Price

Figure 1

Session 16:00 – 17:30
Energy and society

Room: HSZ/004, hybrid
Chair: Jakob Baumgarten

How to get photovoltaics on the roofs? Empirical evidence on the public support for a residential solar mandate in Germany

Tom Schütte, *University of Kassel*

Implications of energy justice for energy system modelling – Public acceptance's impact on renewable energy implementation

Jonathan Hanto, *University of Technology Berlin*

Bioenergy production and local acceptance - Quasi-experimental evidence on the impact on residential property values

Shanmukha Srinivas Byrukuri Gangadhar, *Brandenburg University of Technology*

Exploring pathways for progressing renewable energy communities in Poland: Insights from comprehensive interviews

Anna Kowalska-Pyzalska & Ewa Neska, *Wroclaw University of Science and Technology*

How to get photovoltaics on the roofs? Empirical evidence on the public support for a residential solar mandate in Germany

Beate Fischer[1], Tom Schütte[2] (Speaker), Heike Wetzel[3]

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Keywords: Solar, PV, mandate, acceptance, policy, energy transition, non-market-based

Motivation

The global expansion of photovoltaics (PV) has predominantly been driven by economic incentives. As of the year 2021, about 130 countries had implemented feed-in tariffs or feed-in premiums to promote both large and small-scale renewable electricity generation (REN21, 2022). A more recent trend involves the supplementary introduction of solar mandates, which necessitate property owners to install PV systems on suitable rooftops, mostly applicable to new buildings and in some cases also to existing buildings. Typically, solar mandates are limited to specific building uses (e.g., office buildings, factory buildings, supermarkets, apartment complexes) and minimum sizes. Solar mandates have already been implemented in some European countries such as Greece, Italy, Austria, Germany, Belgium, and outside Europe in California (USA) , and in Tokyo (Japan).
At present, there is no solar mandate in place at the federal level in Germany. As stipulated in the Coalition Agreement of the current government, the introduction of such a mandate is proposed for mandatory application in new commercial buildings and as a standard requirement for residential buildings (Bundesregierung, 2021). While solar mandates have been instituted in nine out of sixteen federal states and some municipalities, only four federal states have hitherto implemented solar mandates specifically for residential buildings. The latter is a subject of considerable debate. While proponents argue that it could accelerate the expansion of photovoltaics and usefully complement existing economic incentives, critics of such a requirement fear that the associated costs could discourage roof renovations and adversely affect the acceptance of photovoltaics, thereby undermining the goals of the energy transition in general. The objective of our analysis is to evaluate whether a residential solar mandate in the event of roof renovation is a useful complement to economic incentives for further PV adoption.

Methods

Using probit and tobit models, we first analyze the determinants that influence PV ownership (Model 1) and PV installation intentions (Model 2) of single-family homeowners. We then examine the factors that explain homeowners' support for a residential solar mandate (Model 3) and their perceptions of its effectiveness (Model 4). The empirical results in this study are based on data from a survey conducted among electricity customers of an energy supplier in the metropolitan area of Cologne, Germany. Notably, there was no residential solar mandate in effect in the study area at the time of the survey.

Results

We find that a residential solar mandate is a rather unpopular policy measure among homeowners. Nevertheless, it addresses two important factors that increase the willingness to install a PV system: A solar mandate institutionalizes the social desirability of roof use for the generation of PV electricity and thus addresses an important factor that explains the willingness to install in our analysis, namely the perception that the personal environment expects further PV adoption. In addition, we show that an upcoming roof renovation increases the likelihood of a high intention to install PV. This window of opportunity could be better exploited with a residential solar mandate. In addition, our analysis shows that the belief that a PV system is a good investment is very important for the ownership of such a system. We conclude that it does not exempt the legislature from regulating market conditions in such a way that surplus electricity that cannot be used in households is appropriately remunerated - whether through private aggregators or feed-in tariffs, for example. The results of our analysis should also raise awareness of the fact that a solar mandate harbors the risk that homeowners may be financially overburdened in the event of a roof renovation. Regarding support for a solar mandate, we see that the perceived effectiveness of such a mandate has a strong influence on homeowners' support. In turn, perceived effectiveness is closely related to the perceived cost savings and perceived environmental benefits of photovoltaics. Our study confirms results from previous research on PV adoption, which identified a relevant set of attitudinal variables toward photovoltaics. Furthermore, we show that controlling for risk preferences, patience, key building characteristics, and disposable financial assets improves the understanding of solar PV adoption decisions.

Implications of energy justice for energy system modelling – Public acceptance's impact on renewable energy implementation

Jonathan Hanto[1] (Speaker), Alexandra Krumm[2], Martha Hoffmann[3], Nikita Moskalenko[4]

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Keywords: Energy System Modeling, Acceptance, Just Transition

Motivation

"In the dynamic landscape of energy system modeling, a focus on equity and fairness becomes increasingly imperative. Techno-economic aspects and cost-efficiency cannot be the only criteria in advancing the much-needed energy transition in politics and society. Recognizing and addressing social equity concerns and including affected actors is vital in advancing the transition to renewable energy, as resistance to implementation can stall emissions reduction action.

Energy system models are a key tool to evaluate trends and examine scenarios of potential future scenarios based on techno-economic assumptions often informing strategies and decisions regarding the energy transition. As we aim to better comprehend the complex web of technological advancements, policy formulations, and societal dynamics, understanding and properly representing aspects of energy justice in energy system modeling is imperative for shaping a more inclusive and ethical energy transition [1].

This study aims to improve the representation of justice aspects in energy system modelling using a two-step approach. Firstly, it employs a systematic literature review aimed at evaluating the current incorporation of justice aspects into energy modelling. Secondly, the Global Energy System Model (GENeSYS-MOD) is modified to integrate the justice indicator "Acceptance" identified in the first step. Subsequently, a case study is conducted in Germany to investigate the impact of the indicator on the energy system from 2018 to 2050. The findings are then analyzed to derive policy implications and provide insights to improve energy system modeling in accordance with a more equitable approach."

Methods

First, we conducted a structured literature review to assess justice considerations in energy modeling, using a semi-structured approach to define key concepts. A search on Web of Science yielded 1,771 papers from 2017 to 2022, with 85 meeting inclusion criteria. We evaluated justice concepts, dimensions, groups, indicators, and integration methods across all 85 papers. Based on multiple parameters such as data availability, temporal scale, and regional scale, acceptance was chosen as the indicator best suited to be implemented in GENeSYS-MOD.

The Global Energy System Model (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. Its main strength lies in the simultaneous optimization of capacity expansion, energy generation, and dispatch of all energy sectors, which leads to an endogenous optimization of demand considering interactions between all energy sectors as illustrated in Figure 1.

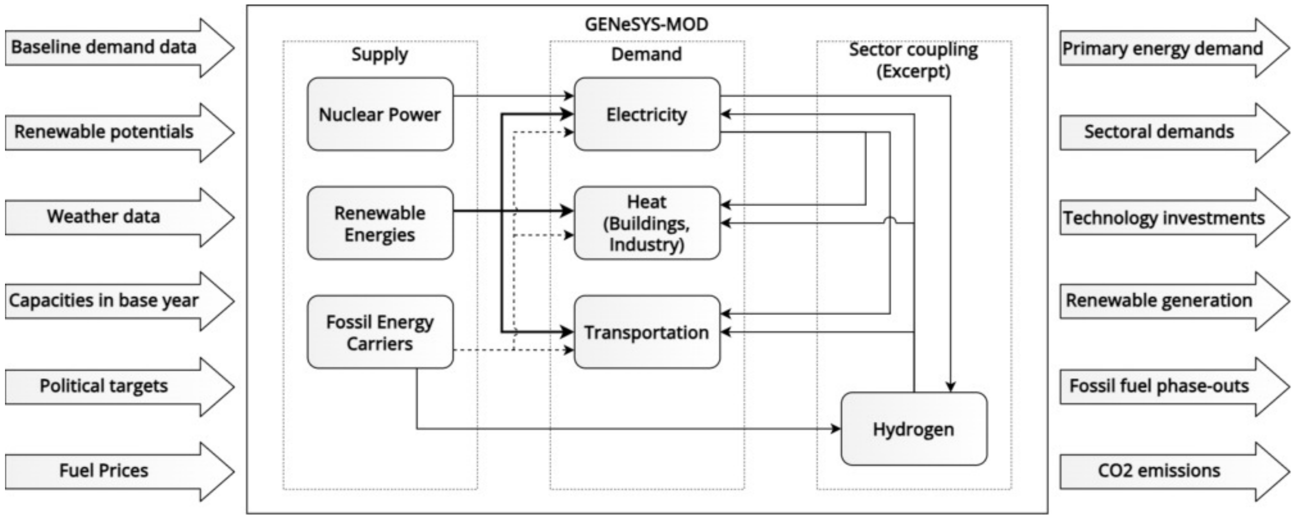

Figure 1

To integrate acceptance into our model, we sourced data from a Hertie School of Governance's analysis on local climate protection attitudes in Germany. Approval levels, ranging from 0-100%, were assessed for specific policies or technologies. This data enabled us to assign acceptance values to each technology in each German federal state, reflecting public sentiments. Average acceptance per year is calculated by multiplying technology- and region-specific acceptance values with corresponding installed capacities, then dividing by total installed capacity per year. The model allows users to set acceptance increase or decrease constraints annually. We apply three scenarios: Base, High Acceptance, and Max Acceptance, providing insights into acceptance's impact on the energy system.

Results

Preliminary findings indicate a rise in average acceptance over the timeframe from 2025 to 2050 in all scenarios (see Figure 2). A significant surge in 2030 can be seen as average acceptance experiences a steep incline. This surge is attributed to the phase-out of multiple fossil fuels, driven by emission restrictions. Simultaneously, the installation of new renewable energy sources, elevates the overall acceptance within the energy system across all scenarios.

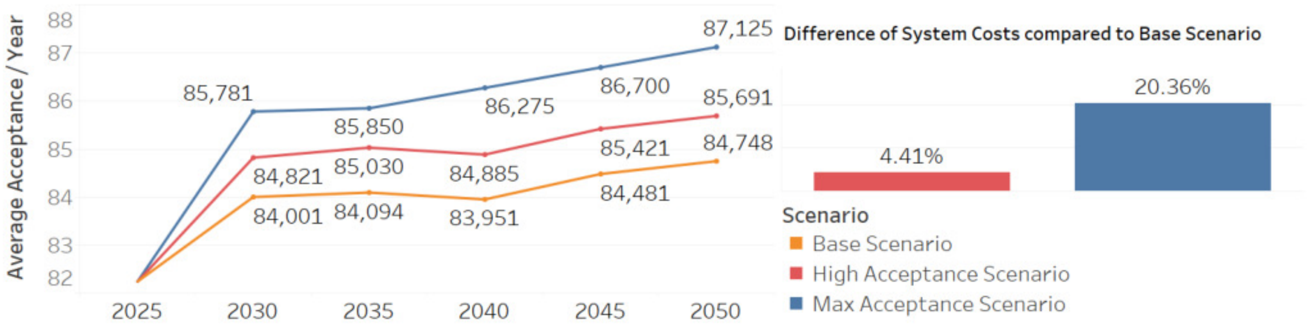

Figure 2

Comparing the scenarios, the High Acceptance Scenario shows a significant increase in average acceptance over the full model period, peaking in 2050 at 85.7 average acceptance. The same goes for the Max Acceptance Scenario that reaches a much higher surge in 2030 and reaches a higher peak at 87.1 average acceptance in 2050. However, this surge in acceptance comes with a trade-off, as total energy system costs rise by over 4% in the High Acceptance Scenario and surpass a 20% increase in the Max Acceptance Scenario. Essentially, the energy system is trading acceptance for increased overall system costs.

Examining the regional power production distribution in Figure 3, a trend towards solar PV, with higher acceptance compared to wind, is notable in the High Acceptance Scenario. This results in increased solar production across all federal states. In the Max Acceptance Scenario, this trend intensifies as power production shifts southward to Bavaria, capitalizing on the region's high solar potential while simultaneously increasing acceptance.

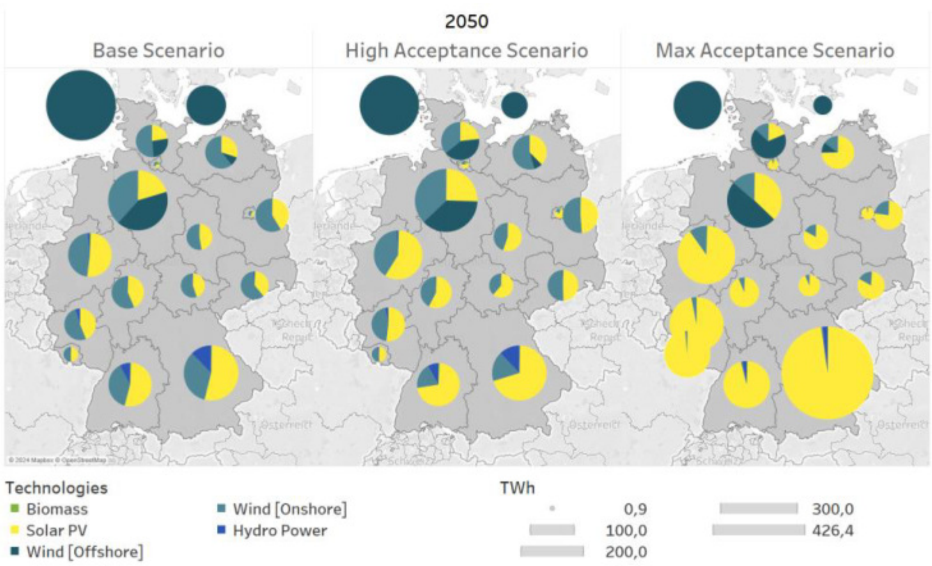

Figure 3

The preliminary results of this study offer dual applications: firstly, they can inform strategic planning to shape a more widely accepted energy system. Secondly, the results can play a pivotal role in guiding political decisions and policy formulations. By pinpointing technologies and regions where an increase in public acceptance would yield the most significant reduction in overall system costs, our findings provide a valuable foundation for crafting targeted policies.

Bioenergy production and local acceptance - Quasi-experimental evidence on the impact on residential property values

Shanmukha Srinivas Byrukuri Gangadhar[1] (Speaker), Christin Hoffmann[2], Felix Müsgens[3]

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Keywords: Bioenergy, Local acceptance, differences-in-differences, Hedonic pricing

Motivation

Considering the energy transition of Germany, expansion of renewable energy infrastructure in the coming years is inevitable. But expansion of energy infrastructure especially when negative externalities are associated can be subject to opposition from the general public. Hence acceptance research becomes vital.

Bioenergy is one of the most important forms of renewable and sustainable energy. In countries like Germany, renewable energies such as solar are seasonal, bioenergy balances the grid with its reliability. Bioenergy, the third biggest in the country's energy mix, is a reliable alternative to transition from nuclear energy. With decentralized energy production, it aligns well with the energy transformation goals of Germany. Further advancements along with CCS (carbon capture and storage) make it the only negative GHG energy source.

While having several perks, bioenergy also comes with negative externalities such as noise, odor, safety concerns, visual landscape pollution and increased local transport. These factors play a crucial role in the overall acceptance of this technology.

Looking at the literature, while there is extensive research on the acceptance of other renewable energy sources such as wind and solar, the research on the acceptance of bioenergy is limited. Existing research indicates several factors that can affect the acceptance of bioenergy such as trust, smell perception, information and awareness, political and cultural contexts, and literacy. To the best of our knowledge, only longitudinal and online surveys are conducted to measure the acceptance of bioenergy in Germany. We aim to contribute further by analysing the effect of bioenergy plants on housing prices in their vicinity.

Methods

Our study considers all the bioenergy plants commissioned between 2007 and 2022, and using hedonic pricing and difference-in-difference (DiD) estimation, analyses their effect on housing prices in their vicinity during the same period. The bioenergy data is taken from the MaStR

(Marktstammdatenregister) database and the housing prices data is supplied by ImmobilienScout24, one of the largest real estate online advertising platforms in Germany. The spatial resolution of housing data is 1km^2 grid cells defined by the INSPIRE (Infrastructure for Spatial Information In Europe) Geographical Grid System.

The bioenergy plants data comprises information on 16,156 plants with several variables such as location, capacity, year of commissioning, system, type of input material etc. Based on capacity and type of input, these plants are further segregated as small, medium and large plants and gaseous, liquid and solid plants. For analysis, we call the region within 3km radius of a plant as the treatment group and the region between 3 and 8km as the control group. The treatment group region is divided into 0.5km, 1km, 2km, and 3 km buffer zones (fig1). Our analysis takes the first occurrence of a bioenergy plant within a grid cell as treatment and takes the plant with the highest capacity as treatment in case of the presence of multiple plants.

We employ the modified DiD strategy proposed by De Chaisemartin and d'Haultfoeuille (2020) to overcome the identified limitations of the traditional two-way fixed effects (TWFE) estimator. Hence we estimate the effect using, the TWFE strategy for the sake of comparison (ß), De Chaisemartin and d'Haultfoeuille (2020) for instantaneous and dynamic effect (did_m), and De Chaisemartin and d'Haultfoeuille (2022) for average effects and robustness check (did_l). We further analyse the segregated data to assess the effect of plant characteristics on acceptance.

Results

After verifying that the common trend assumption holds, we estimate the instantaneous, dynamic, and average effects of the commissioning of bioenergy plants on housing prices in their vicinity. We find a significant instantaneous impact between −0.6% and −0.3% on housing prices caused by the commissioning of bioenergy plants in the vicinity of 0.5 to 3 km. This effect was not identified by the traditional TWFE approach we presented for the sake of comparison.

Our analysis for average and dynamic effects over the three years following commissioning reveals that only for very close properties in the distance d ≤ 0.5 km an on-average negative effect is observed which didn't persist for the following years. For distances between d ≤ 1 km and d ≤ 2 km, we identify positive significant impacts between 1.2% and 1.6% with one year lag. These ambiguous results are in line with Zemo et al. (2019) who also identified a strong dependence on the size of the installed bioenergy plant. Hence this analysis is followed by controlling for the segregated data based on capacity and input. We find that medium-sized energy plants and the types that use a gaseous energy source and have on-site electricity production have clear and negative impacts on housing prices in their vicinity. On the other hand, bioenergy plants that use liquid and solid materials as input has a positive impact on the housing prices in proximity.

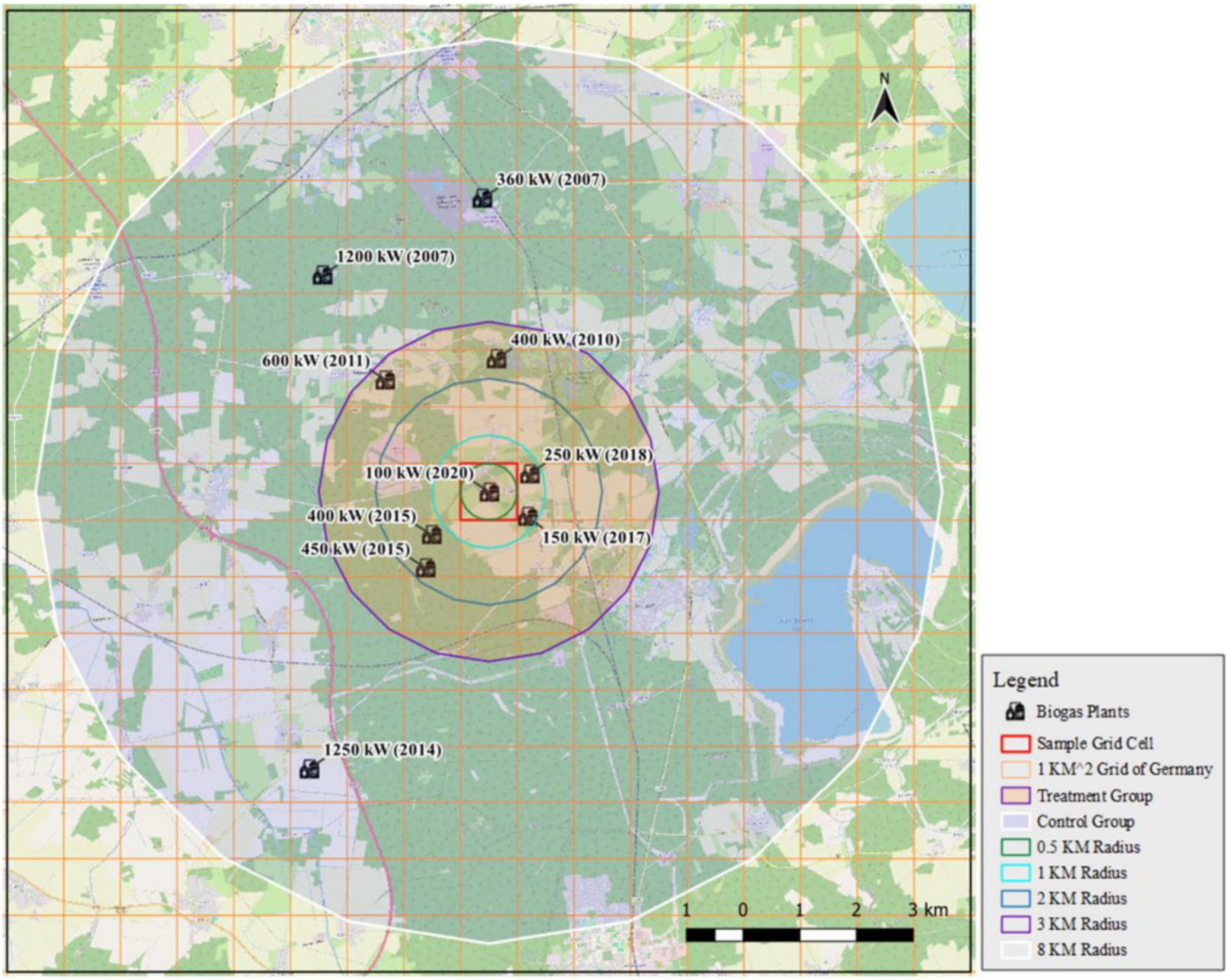
360 kW (2007)
1200 kW (2007)
400 kW (2010)
600 kW (2011)
250 kW (2018)
100 kW (2020)
400 kW (2015)
150 kW (2017)
450 kW (2015)
1250 kW (2014)
N
1 0 1 2 3 km
Legend
Biogas Plants
Sample Grid Cell
1 KM^2 Grid of Germany
Treatment Group
Control Group
0.5 KM Radius
1 KM Radius
2 KM Radius
3 KM Radius
8 KM Radius

Figure 1

Exploring pathways for progressing renewable energy communities in Poland: Insights from comprehensive interviews

Anna Kowalska-Pyzalska[1] (Speaker), Ewa Neska[2] (Speaker), Maksymilian Bielecki[3]

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Keywords: renewable energy community, in-depth interviews, PESTEL analysis, prosumers, experts

Motivation

The concept of the Renewable Energy Community (REC) has come up as a response to the current challenges of the climate change and energy transition. RECs apply the latest digital technologies to unlock the potential of renewables and create an environmentally friendly ecosystem, in which the community can produce, store, and consume energy locally (EC, 2018). As a new entity, REC may alter existing electricity market models by transforming passive consumers into active prosumers (Köppl et al. 2022, Neska & Kowalska-Pyzalska, 2022). Moreover, the REC concept has the potential to be not only innovative, but more importantly, an impactful solution for society as a whole, not just individuals.

Although RECs have been already studied from various perspectives, to our mind the issues of consumer approaches towards REC in Central and Eastern Europe has been understudied. Hence, this research delves into the distinctive RECs in Poland – the largest country in this part of Europe, with a primary focus on the unprecedented surge in photovoltaic (PV) installations within the last 5 years that has been experienced within the country. The prosumer revolution in Poland, propelled by unforeseen factors like financial support mechanisms and external events, showcases the dynamic and unpredictable nature of citizen-led energy initiatives such as RECs. The remarkable increase in PV installations in Poland, surpassing forecasts, emphasizes the influence of unexpected positive feedback loops compared to intentional policy actions. This underscores the distinctive and essential role of citizen initiatives in shaping the energy landscape, diverging from the top-down approaches seen in neighboring markets.

Methods

Within this study we aim to analyze the perceived incentives and barriers to participation in RECs from the point of view of various market actors: first (1) current and potential prosumers to learn about their bottom-up approach, and then (2) experts representing: policy makers, top-managers in the energy sector, researchers in social & engineering sciences, representatives of IT, innovation and digital solution industries, to include top-down perspective. Following macro-environmental PESTEL framework, we analyze the main determinants of RECs feasibility, and provide some vital policy insights.

In May and June 2023, we conducted 30 in-depth interviews, out of which 16 with current and potential prosumers in Poland, and 14 with experts in the fields of the energy market, energy law, politics, IT and from academia. Data collected during the interviews were recorded, transcribed and then coded and analyzed using MAXQDA software. In the second step, we have used a PESTEL framework. This framework, as shown in Table 1, consists of 6 elements: political, economic, social, technological, environmental and legal aspects of an analyzed concept. As each of our interviewee had some observations and comments that fill into these categories, we believe that PESTEL is a right tool to organize our analysis.

Results

The discussion of the empirical findings is divided into two parts. First we will give some contextual examples from the interviews with experts, following the PESTEL framework to present the top-down approach towards creation and implementation of RECs. In the next step we focus on the observations from the interviews with prosumers, to reveal the findings from their bottom-up perspective.

We have noticed a similarity between both groups of respondents. Each of them believes that REC can be a cure for current disadvantages of the energy sector. Some of respondents are even sure that REC is just a future and there is no other better way for the energy transition then decentralization of energy production and engagement of the final end-users. Both groups of respondents conclude that among key factors for successful development in REC following conditions must be fulfilled: (1) stable, trustworthy legal regulations, (2) supporting system that from one side lowers the investment cost of participating, and on the other takes care of potentially vulnerable households, (3) profitable, straightforward and reliable business models, which not only provide some financial motivations to participate, but also guarantee an effective system of transactions, (4) educational effort that will raise environmental awareness and increase the social trust which are both necessary for RECs to maintain.

Political	Economic	Social	Technological	Environmental	Legal
• Government activity • Taxes/ subsidies • Long-term strategies • Political stability • Corruption	• GDP • Inlation • Interest & exchange rate • Income level • Demand & supply	• Lifestyle • Demographic • Culture • Religion • Eductaion • Values & believes	• Innovation • IoT • Technological access • Infrastructure • R&D	• Climate change • Emissions • Consumption trends • Natural risks • Environmental policies	• Directives • Strategies • National law • Consumer protection laws

Figure 1

Session 16:00 – 17:30
Residential energy systems II

Room: HSZ/405/H, hybrid
Chair: Lucas De La Fuente

Evaluating district energy systems: Central vs. decentral batteries in dynamic electricity pricing

Karl Seeger, *RWTH Aachen*

Does knowledge of CO2 prices impact homeowners' choices? An analysis of energy retrofit preferences in Germany

Simon Pröse, *University of Kassel*

R Residential electricity consumption patterns in northwestern Switzerland

Valentin Favre-Bulle, *University of Neuchâtel*

Overcoming the landlord-tenant dilemma: a techno-economic assessment of collective self-consumption for European multi-family buildings

Russell McKenna, *ETH Zürich*

Evaluating district energy systems: Central vs. decentral batteries in dynamic electricity pricing

Karl Seeger[1] (Speaker), Chuen-Fung Tang[2], Marius Tillmanns[3], Prof. Dr. Aaron Praktiknjo[4]

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Keywords: Energy System Analysis, Battery Storage, Dynamic Electricity Prices, Linear Optimization, Cost Comparison

Motivation

With the ongoing expansion of renewable energies, the significance of flexibility in the energy system is on the rise. While historical trends saw supply following demand, the current dynamic is shifting, with demand increasingly aligning itself with the available supply. These adjustments can be stimulated by the implementation of flexible electricity prices and facilitated by additional flexibilities, such as battery storage. This paper delves into the interaction between flexible electricity prices and battery storage systems within an energy system designed for districts and distinguishes between the options of centralized and decentralized electricity storage. The primary objective of this paper is to compare district energy systems with centralized and decentralized battery storage under the influence of flexible electricity prices. The analysis explores the variations in capacities and operational management of the technical components and examines their impact on total costs, self-consumption, and the degree of self-sufficiency. Expanding upon the findings presented in the paper, the subsequent phase should involve exploring potential revenue streams arising from engagements with the electricity market, specifically through the provision of flexibility in the district energy system.

Methods

The energy system model is built upon the FINE framework established by Gross et al. (2023) and was developed within the project TransUrban.NRW. The model portrays a multi-node energy system encompassing electricity and heat demand sectors, formulated as a mathematical system of equations. Consequently, it serves as a robust tool for computing optimized energy systems tailored for districts. Input data contains energy requirements for heat, hot water, and electricity for each individual house, both single and multi-family, as well as the potential for renewable energy sources like solar and geothermal energy. The model further considers potential supply technologies and their corresponding technical and economic parameters, designed as a techno-economic bottom-up model. Optimization calculations are executed with hourly resolution, optimizing energy balances for all 8,760 hours concurrently.

The outcome of the optimization process yields the optimal sizing and operational management of technical components, considering factors such as demand, generation, and costs. For instance, the capacities of batteries and PV systems differ based on the energy system model's structure. In Figure 1a the district energy system model featuring a central battery storage system is illustrated. This central battery can be charged either from the electricity grid at hourly flexible prices or from decentralized PV systems. The stored electricity is deployable for heat pumps, meeting household electricity demands, or can be fed back into the grid. In Figure 1b, the decentralized battery configuration mirrors the central system but notably lacks the capability for direct electricity exchange among individual decentralized batteries.

Hourly electricity prices for grid purchases are derived from the exchange electricity price, scaled up to EUR 0.3216 in consideration of implicit additional levies, as depicted in Figure 2.

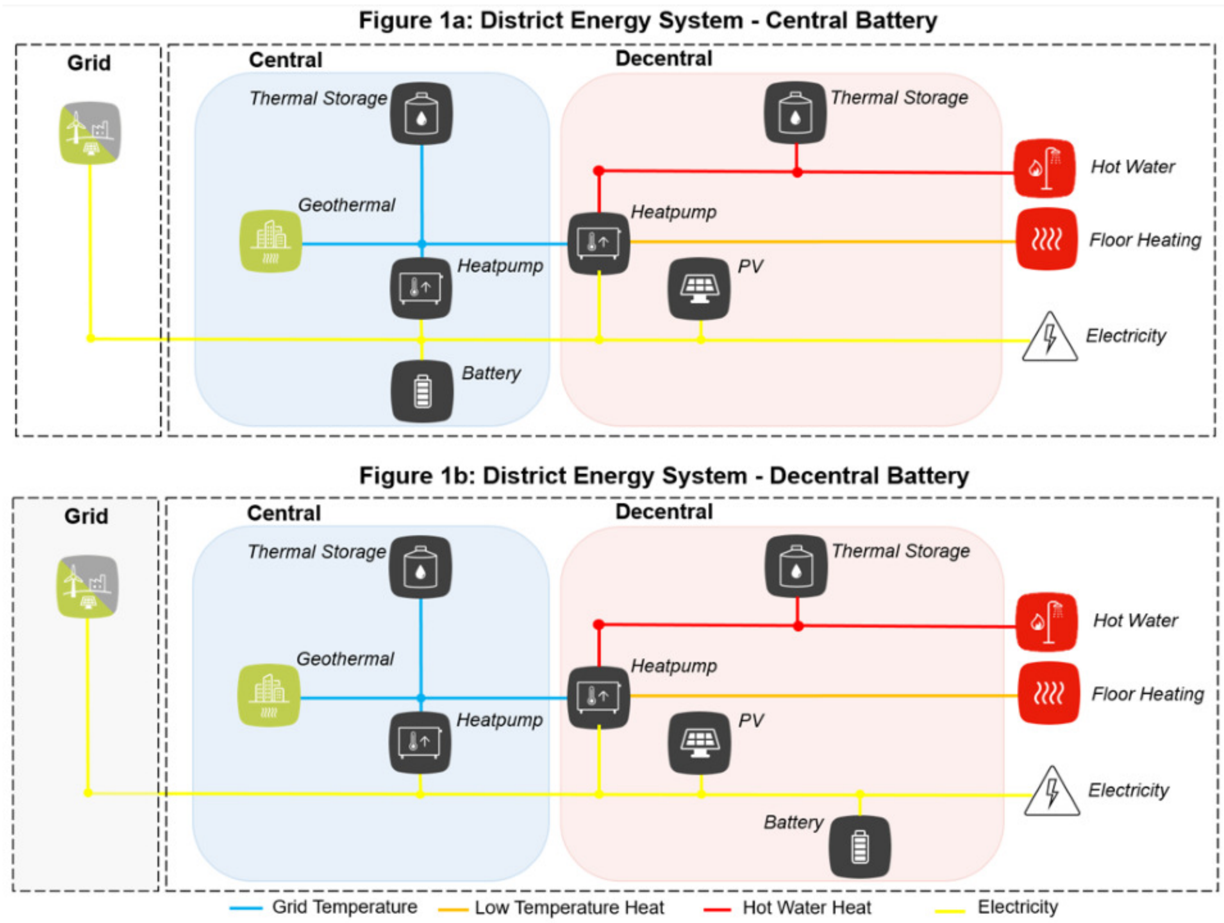

Figure 1

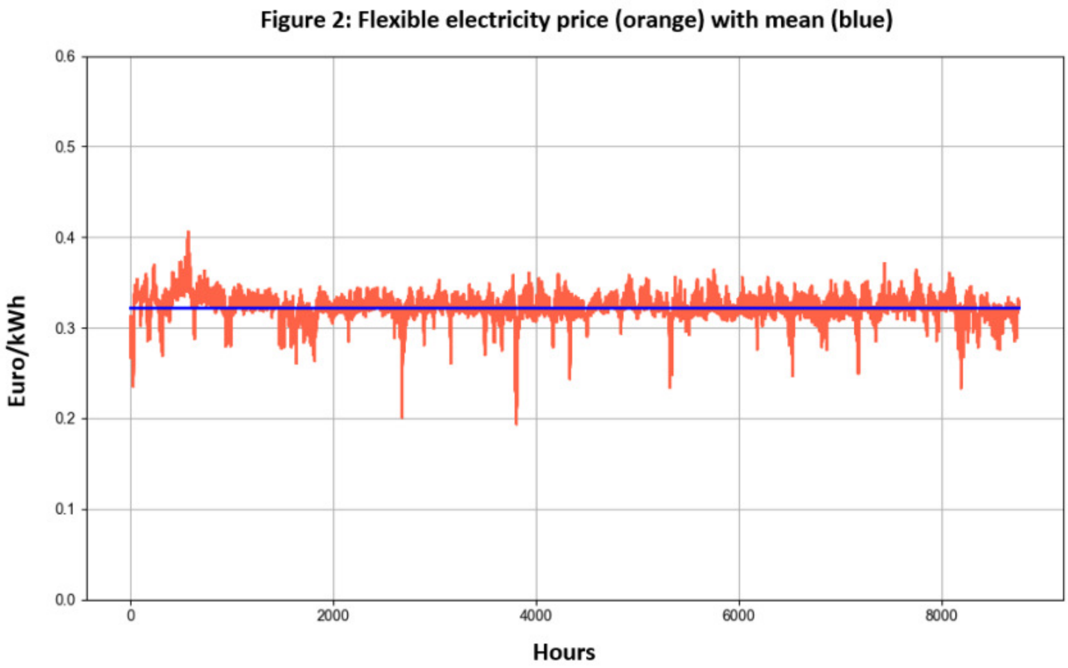

Figure 2

Results

This paper examines the differences between district energy system models with centralized and decentralized battery storage under flexible electricity prices.

The results are illustrated in Figure 3. The total annual costs for setting up and operating the energy system to meet the demand for electricity, heat and hot water for the energy system with centralized batteries increase by 7.7% from 361,410 euros/a to 389,220 euros/a compared to the decentralized case. The differences are mainly driven by the costs of the demand for electricity from the grid (166,540 euros/a vs. 200,308 euros/a). The capacities for electrical storage (559 kW vs. 446 kW) increase for the centralized system compared to the decentralized, while PV capacities are higher as well (476 kW vs. 325 kW). The degree of self-sufficiency in the centralized energy system rises sharply to 39.46% compared to the case of decentralized batteries with 29.95%. The degree of self-consumption decreases to 87.68% from 100%.

A comprehensive examination of the utilization of centralized and decentralized batteries and their influence on grid electricity consumption remains incomplete. Nevertheless, varying peaks in electricity demand from the grid significantly affect distribution grids and present new opportunities for revenue generation, such as reduced grid charges. Moreover, a thorough investigation into the disparities in participation in the balancing energy market between districts employing centralized versus decentralized electrical storage systems is warranted.

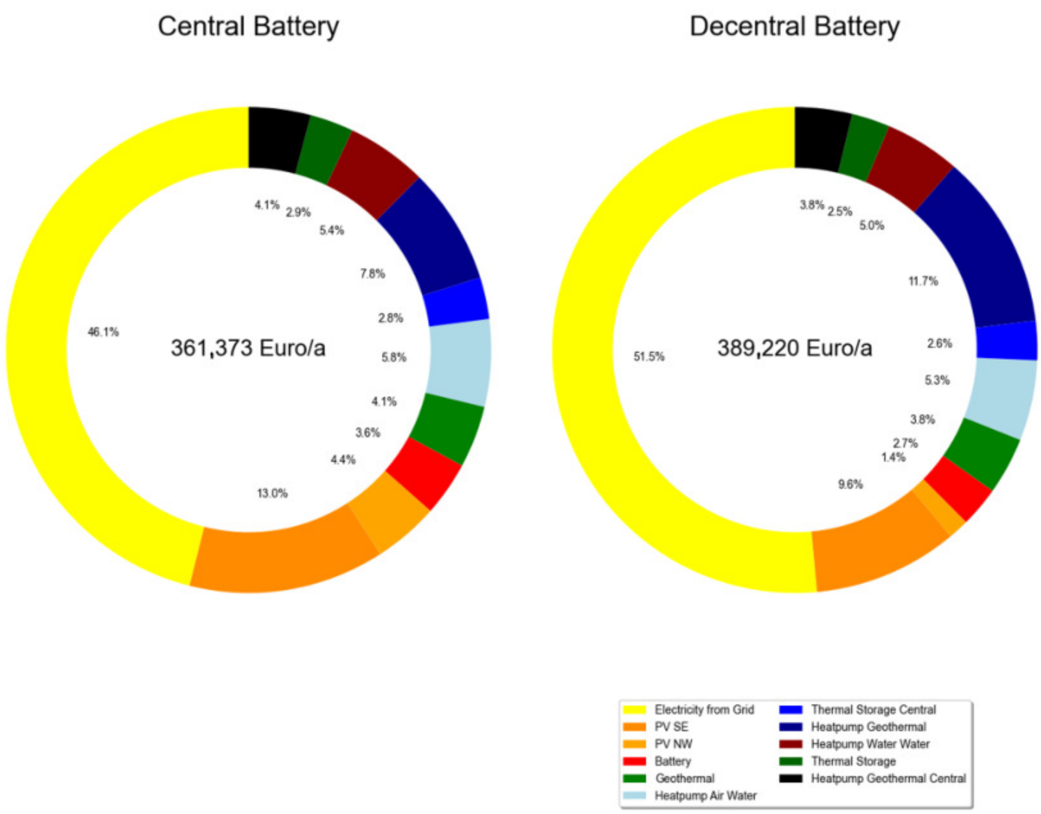
Central Battery
361,373 Euro/a
4.1%
2.9%
5.4%
7.8%
2.8%
5.8%
4.1%
3.6%
4.4%
13.0%
46.1%
Decentral Battery
389,220 Euro/a
3.8%
2.5%
5.0%
11.7%
2.6%
5.3%
3.8%
2.7%
1.4%
9.6%
51.5%
Electricity from Grid
PV SE
PV NW
Battery
Geothermal
Heatpump Air Water
Thermal Storage Central
Heatpump Geothermal
Heatpump Water Water
Thermal Storage
Heatpump Geothermal Central

Figure 3

Does knowledge of CO2 prices impact homeowners' choices? An analysis of energy retrofit preferences in Germany

Simon Pröse[1] (Speaker), Jonas Bender[2], Tom Schütte[3], Heike Wetzel[4]

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Keywords: Energy retrofits, energy efficiency, Carbon price, Information treatments, Discrete choice experiments

Motivation

This paper analyzes the effects of different information about CO2 prices on homeowners' preferences for energy retrofits. The empirical analysis is based on data from a discrete choice experiment. In the experiment, a representative sample of more than 1400 household decision-makers in Germany chose between different energy retrofit options and no retrofit. Households were assigned to a placebo and four information treatments that differed in the type of CO2 price information (in euros per ton per year versus individualized annual CO2 costs) and in the temporal development of the CO2 price (decrease to zero versus low increase versus high increase). We find that homeowners have a strong preference not to retrofit when given the choice. However, there is a significant preference for lower CO2 emissions from the heating system. Across all treatments, we find little to no evidence that different information about the CO2 price influences preferences for heating system technologies, insulation measures or CO2 emissions. This is also true for different subsamples, including homeowners with fossil fuel heating systems and low retrofit activity in the past. Our results suggest that information on future CO2 price developments and their impact on individual CO2 costs is not sufficient to incentivize increased energy retrofits of residential buildings in Germany. In view of the high investment costs, this underlines the importance of additional support measures, such as subsidies for energy-efficient renovations.

Methods

We elicit the preferences of homeowners in Germany when deciding on voluntary energy retrofits. The design of the discrete choice experiment follows Lang et al. (2021) and consists of multiple treatments in a within-and-between-subjects design. Overall, the survey assigns homeowners to four treatment groups and one control group. For each participant, the discrete choice experiment contains twelve choice sets. In the control group after six choice sets, participants receive an additional piece of information that does not change the choice scenario (placebo treatment). It conveys general information about the proportion of residential buildings by date of construction in Germany. The remaining four treatments are designed to reflect the effect of different price developments of a CO2 tax.

In the treatment groups, after six choice sets, participants receive the treatment information. They then answer the remaining six choice sets. At the beginning of the choice experiment, all participants receive detailed and identical information about the hypothetical choice situation. In the experiment, respondents are asked to choose between different hypothetical options for energy retrofits. The attribute levels shown in the stated choice experiment are individualized based on previous responses in the questionnaire (in accordance with Achtnicht and Madlener (2014); Galassi and Madlener (2017)) and are additionally option-specific (inspired by Banfi et al. (2008)). This helps to reduce the hypothetical bias in order to obtain more resilient estimated preferences and willingness to pay. The key dependent variable is the dummy variable ”choice”. It takes the value 1 if a respondent chooses a particular retrofit option in a choice situation and the value 0 otherwise. In contrast to previous studies (e.g., Lang et al., 2021) we include an opt-out option (no energy retrofit), meaning the respondents had the option to stay at their current system and conduct no energy retrofit.

Results

The results suggest that homeowners’ have a general preference towards not retrofitting their homes. However, regarding the preferences for new heating system technologies, we find that homeowners prefer heat pumps over their current heating system. There is also a general trend for higher levels of insulation across the sample. In general, homeowners prefer retrofitting options with lower levels of CO2 emissions.

Regarding information provision of CO2 taxes, we find little to no effect on the retrofit decisions of homeowners irrespective of magnitude and salience of emission taxes. The lack of a significant information effect of the CO2 tax holds true for the choice of heating technology, the extent of insulation, and the preferences regarding CO2 emissions. In the two treatments that include the elimination of the CO2 tax or a moderate increase in the emissions tax, we find no effect on homeowners' preferences. The only significant effect of a CO2 tax information treatment is in the case of high CO2 tax with general information, where we find a stronger preference for lower CO2 emissions. In this treatment we also find a positive preference towards higher heating costs compared to the control group, suggesting a shift in preferences from general heating costs towards lower CO2 emissions. However, this effect vanishes with more salient information about individual costs.

In general, our results suggest that information provision about CO2 taxes does not affect homeowners' (low) willingness to retrofit. Furthermore, our results underline the importance of subsidy measures for energy retrofits. We identify strong preference heterogeneity among homeowners for both heating system technologies and insulation measures. This heterogeneity is prevalent in both our main sample and several subsamples, indicating that it cannot be explained by these characteristics alone.

Table 3: Overview of informational treatments

Indicator	Treatment	Information screen
T_0	Placebo	Neutral
T_1	Zero carbon pricing	CO_2 tax
T_2	Low carbon pricing and salience	CO_2 tax
T_3	High carbon pricing	CO_2 tax
T_4	High carbon pricing and salience	CO_2 tax

Figure 1

Table 1: Attributes and attribute levels in the stated choice experiment

Attribute	Level
Heating system replacement	Gas heating; Gas with solar thermal heating; Heat pump; Pellet heating; No replacement
Scope of the insulation measures	Low; Medium; High; No insulation measure
Investment costs	70%; 85%; 100%; 115%; 130% of the individual specific costs and option-related measures.
Investment cost subsidy	0%; 20%; 40%; 60% 80% of investment costs
Heating and hot water costs 2022	0%; 20%; 40%; 60%; 80% based on the stated or calculated heating cost without carbon tax. Considers option specific scope of insulation measure.
Annual CO_2 emissions	95%; 85%; 75% if option specific scope of insulation measure is low 75%; 55%; 35% if option specific scope of insulation measure is medium 35%; 25%; 15% if option specific scope of insulation measure is high 100% if option specific no insulation measures

Figure 2

Table 5: Mixed logit model estimates in preference space

	Main effects (*Pre-treatment effects*)		Interaction effects (*Every respondent has info on current CO2 tax with general info*)				
	(1) Mean	(2) Std. dev.	(3) Post	(4) Removal CO_2 tax	(5) Individual info on additional yearly costs	(6) Higher CO_2 tax with general info	(7) Higher CO_2 tax with individual info on additional yearly costs
No retrofit	0.313***	2.505***	0.005	−0.032	−0.171	−0.010	−0.025
	(2.92)	(24.67)	(0.02)	(−0.11)	(−0.60)	(−0.03)	(−0.08)
Subsidy	0.122***	0.149***	0.026	0.009	−0.000	0.013	0.031
	(10.04)	(12.82)	(0.98)	(0.25)	(−0.01)	(0.38)	(0.88)
Heating costs 2022	−0.487***	1.418***	−0.353	0.236	0.601	0.921**	0.339
	(−3.25)	(10.14)	(−1.10)	(0.58)	(1.52)	(1.99)	(0.76)
Gas	−0.957***	1.288***	−0.140	0.196	0.041	0.112	−0.056
	(−8.90)	(13.04)	(−0.69)	(0.71)	(0.14)	(0.40)	(−0.20)
Gas-solar	−0.126	1.237***	−0.130	0.183	−0.040	−0.163	0.008
	(−1.50)	(14.63)	(−0.74)	(0.75)	(−0.18)	(−0.64)	(0.03)
Wood pellets	−0.603***	1.723***	0.125	0.045	0.255	0.025	0.124
	(−5.48)	(17.82)	(0.62)	(0.16)	(0.93)	(0.09)	(0.43)
Heat pump	0.363***	1.554***	−0.209	0.272	−0.005	−0.022	0.262
	(4.30)	(19.18)	(-1.33)	(1.21)	(−0.02)	(−0.10)	(1.15)
Low insulation	0.310***	0.272	−0.061	0.065	0.281	−0.122	−0.286
	(3.29)	(0.52)	(−0.32)	(0.25)	(1.04)	(−0.47)	(−1.08)
Medium insulation	0.482***	−0.335	−0.068	−0.012	0.430	0.112	−0.133
	(4.11)	(−1.45)	(−0.29)	(−0.04)	(1.27)	(0.33)	(−0.40)
High insulation	0.635***	−0.650***	−0.239	−0.081	0.637	0.077	0.109
	(4.19)	(−6.25)	(−0.77)	(−0.20)	(1.50)	(0.17)	(0.25)
Emissions	−0.099***	0.428***	−0.017	0.041	0.014	−0.135**	−0.0341
	(−3.98)	(14.60)	(−0.39)	(0.67)	(0.24)	(−2.25)	(−0.59)
Investment cost	−0.161***						
	(−13.25)						
No. of observations	69,696			Respondents per treatment			
No. of respondents	1,452			289	273	289	283

Notes: Mixed logit results for the full sample in preference space. Column (1) reports the mean estimate and column (2) the corresponding standard deviation. The reference categories for the Heating systems (Gas, Gas-solar, Wood pellets, Heat pump) and the insulation level are current heating system and no insulation measures, respectively. Column (3) reports the interaction of the attributes with the placebo treatment indicator. Columns (4-7) report the estimates for each treatment as the placebo treatment as reference category. $*(**, ***)$ denotes that the corresponding parameter is different from zero at the 10% (5%, 1%) significance level.

Figure 3

Residential electricity consumption patterns in northwestern Switzerland

Valentin Favre-Bulle[1] (Speaker), Sylvain Weber[2]

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Keywords: Residential electricity consumption, smart meters, K-means clustering, consumption patterns

Motivation

Electricity is at the root of crucial political issues, covering a country's energy independence and the need for an optimal approach to production and consumption to address climate change. These challenges can be tackled by working on the demand side by developing measures that improve energy efficiency, reduce electricity consumption and/or shift consumption to specific periods. Reducing electricity consumption also helps decrease CO2 emissions, given the indirect production of CO2 associated with electricity generation.

In this context, the residential sector is a key player: for example, Swiss households account for around 35% of the country's electricity consumption (Swiss Federal Office of Statistics, 2021).

Smart meter data represents a major opportunity that can be used to understand and analyse household electricity consumption patterns and trends precisely. By clustering load curves, households with similar consumption patterns can be grouped to create consumption profiles. These can deliver helpful information linked to socio-demographic data (e.g., age, education, etc.) and the technical characteristics of the homes. A growing literature has developed to use these sources of valuable information (Viegas et al. (2016) Energy, Beckel et al. (2014) Energy, McLoughlin et al. (2015) Applied Energy, Rajabi et al. (2020) Renewable and Sustainable Energy Reviews).

Governments can use such information to implement well-targeted instruments and develop demand-side management (DSM), which encourages consumers to modify their level and pattern of consumption to match supply availability. Electric utilities may also benefit from an enhanced understanding of their customers by tailoring marketing campaigns specifically for each segment, thus reaching a more profound impact on electricity usage. Considering electric markets are being deregulated, satisfying customers better may appear crucial to electric utilities.

Methods

Smart-meter data has become increasingly available and provides high-quality hourly and quarterly measurements. The data set at our disposal is electricity consumption data for around

5,000 households in north-western Switzerland. It has been collected with smart meters on an hourly or quarterly basis. It covers several years (2018 - 2023) and is combined with some technical information about the dwellings.

Clustering is an algorithm for grouping individuals with similar characteristics/features that is widely used in research, particularly for analysing electricity consumption data.

In our clustering, we chose six features that could characterise the consumption of the households. First, the data is divided into four typical daily periods: night time (10pm to 7am), morning (7am to 11am), daytime (11am to 3pm), evening (3pm to 10pm). The first feature is the average daily consumption, which allows distinguishing households in terms of consumption level. Features 2 to 5 correspond to the average consumption for each period of the day as a proportion of daily consumption. A sixth characteristic is calculated to capture the consumption variability throughout the periods of the day.

Then, a particular clustering technique (K-means) is applied to these six features and the number of clusters is chosen according to a index of maximisation (Calinski-Harabasz index).

In addition to this primary clustering, two similar cluster analyses are performed separately for each season and day of the week. The aim is to see whether a different number and type of consumption patterns can be detected depending on the season and the day of the week.

Results

The analysis indicates the presence of three clusters (Figure 1) of similar size (1185, 1863, and 1000 households), with clearly different consumption profiles and quantities (Figure 2). The group in red consumes less during the day and more in the evening, with a small peak at midday and a substantial peak in the evening. The group in blue has a large consumption throughout the day, with two similar peaks at noon and early evening. The green group has relatively large consumption throughout the day but a very high peak at midday and a small peak in the early evening.

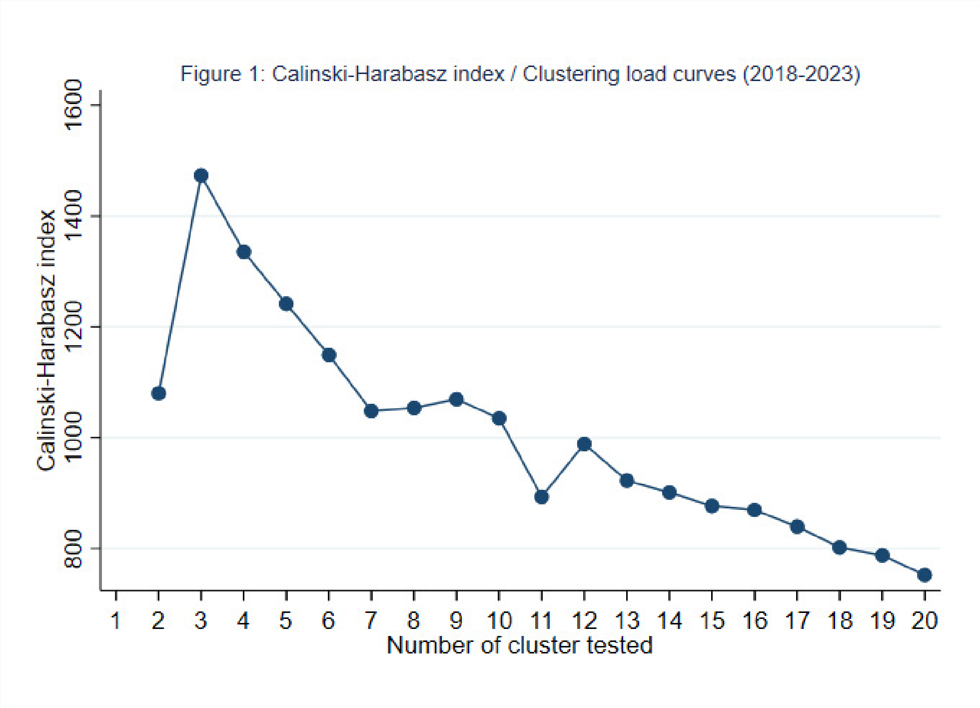

Figure 1

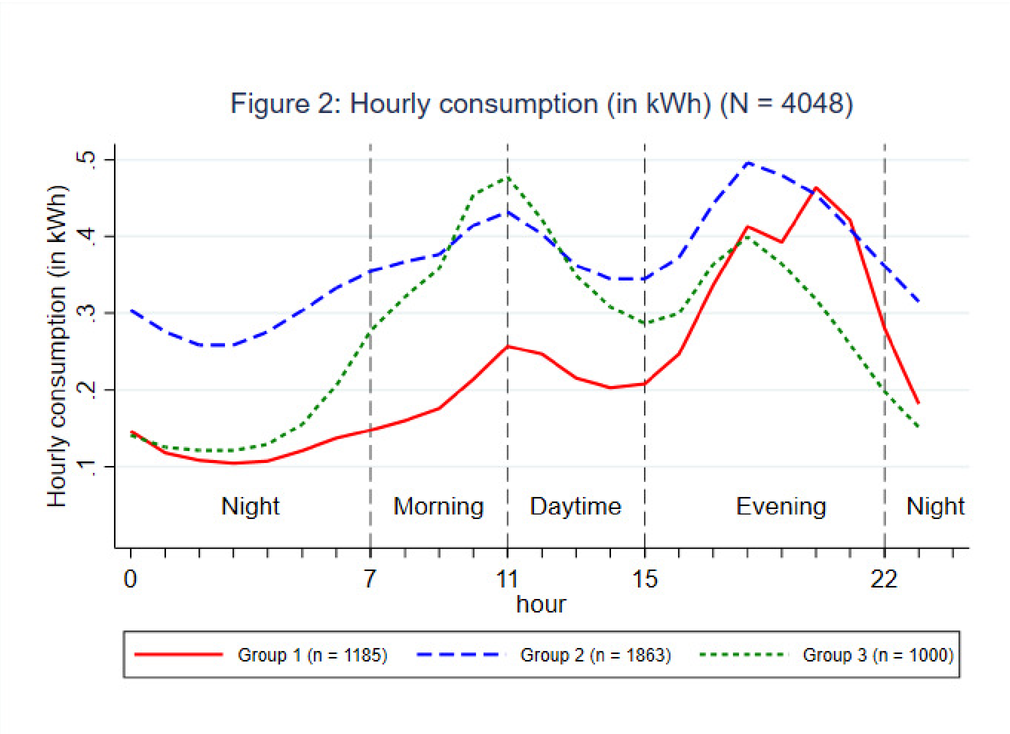

Figure 2

The consumption patterns change dramatically between the three groups. Thus, if an electricity provider plans to introduce a dynamic tariff or a government decides to impose an incentive to consume less at midday, the impact would be different depending on the household's group, and they need to consider that.

Performing clustering on data separated by season or day of the week produces interestingly different results. Beyond a logically greater quantity consumed in winter, clustering only recommends forming two groups for this season. So, profile diversity seems less important during winter than in other seasons.

For weekend days, the optimal clustering also requires two groups (Figure 3). Compared with the primary clustering, the group with a large consumption peak in the evening seems to have disappeared. This suggests this group mainly comprises people working during the week who do not consume much at midday but change their consumption during the weekend.

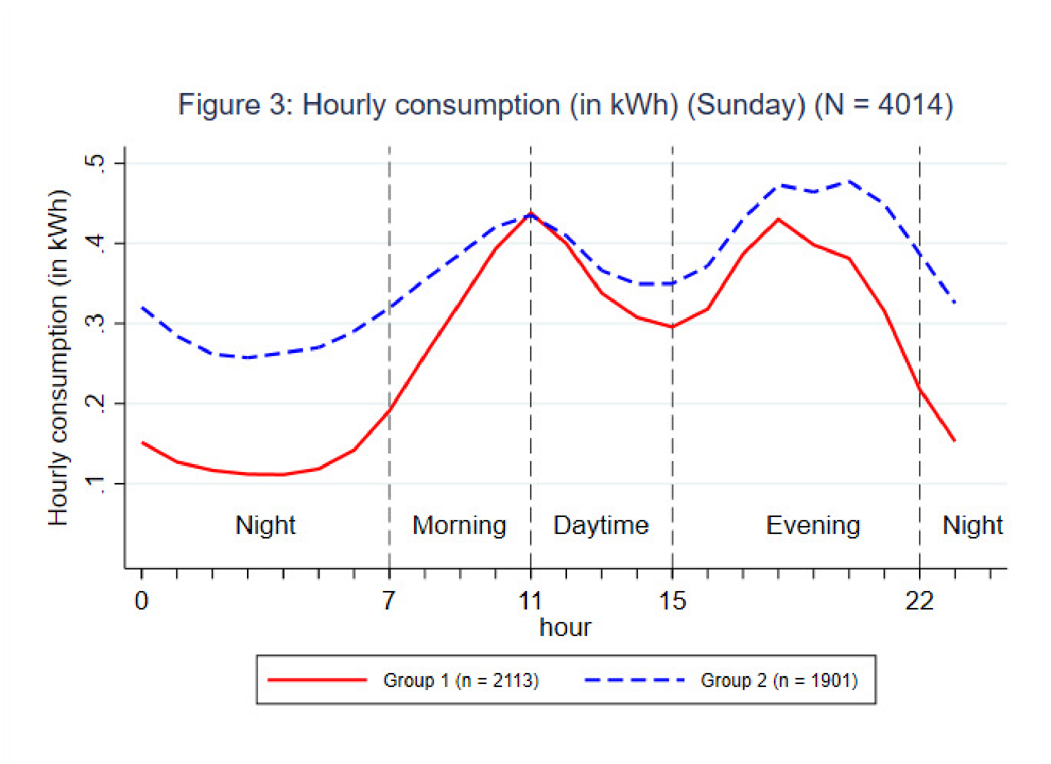

Figure 3

A multinomial regression model will be used to link consumption profiles to socio-demographic variables of households. These data will be collected in July 2024. This will enable us to determine the composition of each group according to the following variables: age, household composition, children, employment status... Ultimately, it may be possible to determine the type of household simply by observing electricity consumption curves.

Overcoming the landlord-tenant dilemma: a techno-economic assessment of collective self-consumption for European multi-family buildings

Russell McKenna[1] (Speaker), Christoph Domenig[2], Fabian Scheller[3], Phillipp Andreas Gunkel[4], Julian Hermann[5], Claire-Marie Bergaentzlé[6], Marta Alexandra dos Reis Lopes[7]

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Keywords: Distributed energy, Collective self-consumption, Landlord-tenant dilemma, Multi-family buildings, Apartments, Shared photovoltaics

Motivation

Around half of the EU population lives in multi-family buildings, in which the landlord-tenant dilemma poses a significant barrier to low-carbon retrofits. Collective self-consumption (CSC) could present a promising way to overcome this barrier by creating mutual benefits for landlords and tenants. However, the techno-economic, climatic, and regulatory conditions for CSC show large variations in European countries, which raises the question how they will impact CSC benefits. In this study four different CSC regulations are integrated into a mixed-integer linear programming model, which determines the optimal retrofitting measures in a renter-occupied multi-family building under varying energy cost, climate, and envelope efficiency levels. The results show that CSC is beneficial for both landlords and tenants in all of Europe except for buildings in Western and Central Europe with an average U-value below 1.4 W/m^{2}K and gas costs below 0.08 €/kWh. The findings also suggest that the landlord-tenant dilemma for decarbonizing heat persists in all European climates, pointing to the need for further support measures. In Southern Europe these could be provided in the form of more favorable CSC incentives for buildings with heat pumps, while in Central and Western Europe other measures, e.g. subsidies for heat pumps and renovation, are required.

Session 16:00 – 17:30
Household PV systems

Room: HSZ/301/U
Chair: Felix Meurer

Prosumers with PV-battery systems in the electricity markets

Felix Meurer, *University of Duisburg-Essen*

Household responses to the tax treatment of income from solar PV feed-in in Germany

Reinhard Madlener, *RWTH Aachen*

Solar prosumage: Interactions with the transmission grid

Mario Kendziorski, *University of Technology Berlin*

enerWARD: Corporate sustainable bonds: Determinants of the Greenium

Christoph Sperling, *TU Dresden*

Prosumers with PV-battery systems in the electricity markets

Felix Meurer[1] (Speaker), Marco Sebastian Breder[2], Christoph Weber[3]

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Keywords: Prosumage, Energy Policy, Tariff Design

Motivation

Previous studies have shown that decentralised sector coupling and flexibility options play an important role in the integration of renewable energies into energy systems in the future. Recent developments include increased investments in PV battery systems underlining the increased importance of decentralised flexibility. At the same time, the present design of retail tariffs means that private households operate coupled PV battery systems primarily with the aim of increasing self-consumption, although the flexibility could be utilised to support the power system.

Methods

Our contribution examines in a stylised setting which adjustments to the regulatory framework can work towards a system-oriented operation of decentralised flexibilities with a focus on PV battery systems. The generation-portfolio at the wholesale level is characterised by a significant share of renewables resulting in volatile prices. When considering decentralised actors, we focus on prosumers, which in our simplified setting are depicted as representative households with a PV system and battery storage.

We use two iteratively coupled linear programs to combine the optimisation calculus of decentralised actors at the retail level with cost minimisation at the wholesale market level. In our setting, we examine the effect of various distortions that induce deviations of prosumer behaviour from the system optimum. We especially investigate the impact of time-independent retail tariffs, fixed feed-in tariffs and surcharges on capacity investments, wholesale market prices and system cost.

Results

The results show how real-world electricity market practices affect investment decisions on both the household and wholesale market sides. In addition to investment decisions, we focus on prosumage behavior, i.e. electricity procurement, grid feed-in and storage use. Overall, we can assess the long-term effects of prosumage incentives on the system development under realistic market conditions as well as the distributional effects on prosumers and other end-users.

Household responses to the tax treatment of income from solar PV feed-in in Germany

Jannik Fleiter[1], Ayse Tugba Atasoy[2], Reinhard Madlener[3] (Speaker)

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Keywords: Prosumer, Solar PV, Compliance costs, Bunching, Regression discontinuity design, Difference-in-bunching analysis

Motivation

We examine possible adverse side effects of feed-in remuneration schemes caused by tax compliance costs. Specifically, for the case of Germany, we study how private households respond to a tax policy instruction issued by the German Federal Ministry of Finance in June 2021, enabling to evade tax compliance obligations if the installed capacity is ≤ 10 kWp. A decision model and two different empirical models are employed to show how such compliance costs distort both deployment decisions and capacity choices. We find that the tax instruction led to a change of the capacity distribution of newly built PV systems towards 50-65% intensified excess bunching slightly below 10 kWp, leading to an inefficient use of rooftop space. The lacking cross-sectional variation in the data and a large number of con-founding events in the observation period calls for further research to corroborate our findings. Using methodical approaches taken from the bunching literature and discontinuity analysis, we estimate potential changes in the average capacity choice.

Methods

We use a simplified decision model, based on which we theoretically investigate under which circumstances tax compliance costs become relevant for the decision-making of prospective PV adopters and where the BMF tax policy instruction may distort the decision. To estimate the influence of compliance costs induced by income tax obligations, we examine the response of residential PV adopters to the BMF tax instruction from June 2021. For that purpose, we exploit on the fact that the publication of the instruction constitutes a quasi-experiment where households who commissioned their system before June 2021 are the control group, and households who deployed the system after the instruction came into effect depict the treatment group (time series analysis). Furthermore, the policy instruction only applies to systems < 10 kWp, which suggests an analysis of the distribution of system capacities around the threshold before and after the instruction came into effect (distribution analysis). The collected data from the Marktstammdaten-Register (MaStR), representing repeated cross-sectional data, enables the use of both approaches. We use bunching estimation and regression discontinuity design (RDD) as suitable approaches to identify excess bunching. A subsequent difference-in-bunching (DiB) analysis further provides evidence for time-delayed responses. In a second step, we adapt these findings to specify a model for a RDD approach, enabling us to include control variables to better analyze quantitative effect sizes for the impact of bunching on the average system capacity.

Results

Significant bunching of PV system capacities slightly below the cut-off level of 10 kWp is present in all observed months and across all subsets of different population density. The extent of bunching, though, declines greatly in the first half of 2021. Between July and September 2021, the dynamic reverses, and the excess mass increases by 50-65% compared to the minimum value until the end of the observation period. This behavior is consistent across all subgroups. The general intensity of bunching, while still very pronounced, is found to be less distinct for areas with higher population density than for less densely populated areas. Furthermore, the initial decrease of the bunching measure is greater in areas with high population density, as compared to areas with fewer inhabitants per square kilometer. Our findings provide evidence for the assumption that the population density indeed is an appropriate proxy for the rooftop size, and, that households with smaller average roof sizes are, on average, less affected by regulations that feature discontinuous treatment at the 10 kWp threshold. Overall, we find that strong evidence for substantial bunching slightly below 10 kWp, which very likely is induced by the BMF tax instruction. Furthermore, the results indicate that this effect goes beyond the natural impact of bunching alone. While the preliminary considerations predict this behavior, the empirical results are insufficient to unambiguously confirm the theory.

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 an updated version of ELMOD (based on 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 Elmod to generate wholesale price time series for mid-term future scenarios in Germany by solving linear dispatch and redispatch optimization problems. Elmod, 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 Elmod 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.

enerWARD:
Corporate sustainable bonds: Determinants of the Greenium

Christoph Sperling[1]

[1] *TU Dresden*

Session 16:00 – 17:30
Advanced modelling and weather analysis

Room: HSZ/304/Z
Chair: Martin Kittel

High-resolution modeling of heating-cooling demand under future climate change scenarios
Camila Villarraga Díaz, *German Aerospace Center (DLR)*

Variable renewable energy droughts in the power sector – a model-based analysis and implications in the European context
Martin Kittel, *DIW Berlin*

A binary expansion approach for the water pump scheduling problem in large and high-altitude water distribution networks
Denise Cariaga, *The University of Edinburgh*

Electricity markets in a fully decarbonized economy
Frank Heinz, *RWTH Aachen*

High-resolution modeling of heating-cooling demand under future climate change scenarios

Camila Villarraga Díaz[1] (Speaker), Hans-Christian Gils[2]

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Keywords: Heating-Cooling Demand, Energy System Modeling, Climate Change Scenarios, Spatio-temporal Disaggregation

Motivation

Energy system modeling is essential for analyzing and selecting carbon neutral system designs that are able to ensure secure, sustainable and affordable energy supply. Climate change has a considerable influence on the energy system and can affect it in many different ways. One of the most significant is the effect on energy demand for heating and cooling purposes caused by more intense temperature conditions.

A trend towards decarbonization for the heating sector, coupled with increasing cooling requirements, would have a significant impact on the future provision of electricity. Therefore, modeling future energy demand and its dynamics and interactions is highly important for decision-making in energy system planning. However, methods for developing realistic future energy demand in high resolution have been minimally studied or completely ignored in the energy system and market modeling which leads to significant errors and inaccuracies, specially under medium- and long-term future scenarios.

This study proposes a methodology for delivering time series of energy consumption at high spatial-temporal resolution, and suitable for coupling with different developed energy modeling tools. Thus, it enables a more robust prediction of the future energy system and its economic feasibility on the basis of high-quality input data.

Methods

In this study, a method to generate high-resolution time series of heating and cooling demand under different future climate change scenarios is been developed. The modeling is based on the degree-day model, supplemented with refinements and applied on Germany, as a case study.

Starting at the upper stream shown in the Figure, a separate parameterization of heating and cooling demand using very high-resolution meteorological reanalysis data is performed.

This approach in combination with several socio-economic aspects and technical thermal characteristics has the advantage of allowing the derivation of standardized, regionally scaled heating and cooling demand profiles. As input for the heating component of the model, natural gas datasets are essentially used, and for the cooling component, time series of electricity demand are used.

Finally, the second lower stream makes use of different climate change scenarios (Representative Concentration Pathways, RCPs), where different degrees of greenhouse gas release and altered global warming are applied, in order to predict future heating and cooling energy demand under the influence of climate change, while preserving its high temporal and spatial resolution.

Results

The disaggregation method aims to deliver hourly profiles for heating and cooling at regional spatial resolution using the NUTS2 classification, where for each region, model specific parameter settings are estimated. However, aggregated national demand series in hourly resolution for Germany have been produced only recently. The obtained output can be validated with the products of other similar space heating and cooling tools (such as the Demand.ninja tool) as well as, against statistical data on energy-use published for the residential and non-residential sectors. Heating and cooling demand projections under future scenarios are currently in the implementation phase, with preliminary results indicating consistent trends of higher electricity consumption driven by an increase in the intensity of winter and summer temperatures.

This method can serve as an interface between different energy system and market models and its outputs will allow enrichment and flexibility of exiting tools for system analysis research and the improvement of energy system modelling.

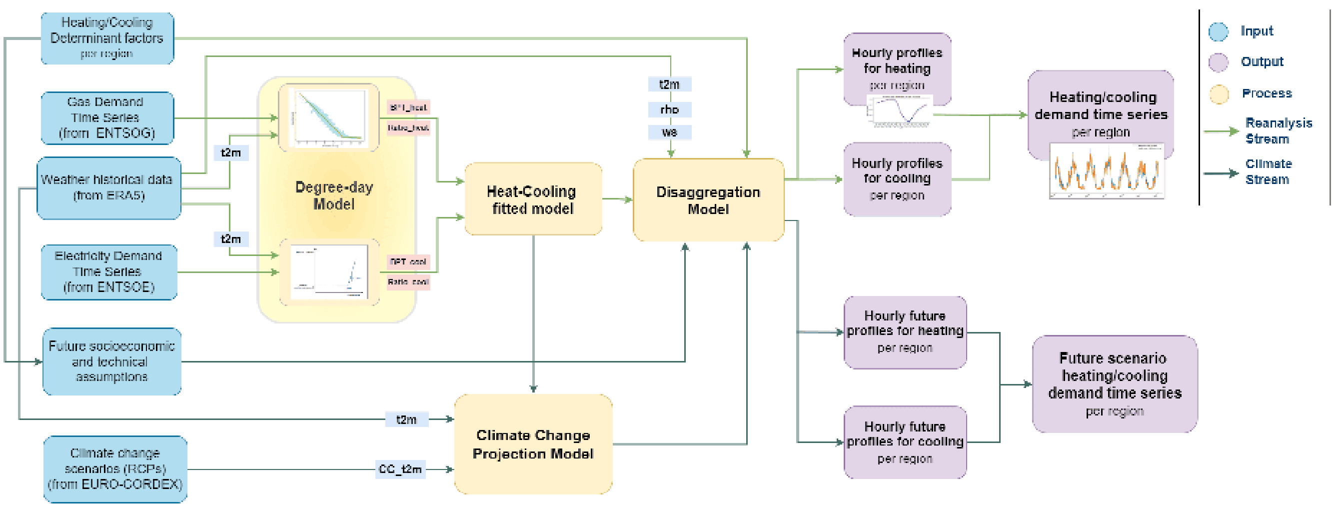

Figure 1

Variable renewable energy droughts in the power sector – a model-based analysis and implications in the European context

Martin Kittel[1] (Speaker), Alexander Roth[2], Wolf-Peter Schill[3]

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Keywords: Variable renewable energy, Dunkelflaute, long-duration storage, energy system modeling

Motivation

The continuous integration of variable renewable energy sources (VRE) in the power sector is required for decarbonizing the European economy. Power sectors become increasingly exposed to weather variability, as the availability of VRE, i.e., mainly wind and solar photovoltaic, is not persistent. Extreme events, e.g., long-lasting periods of scarce VRE availability (VRE droughts), challenge the reliability of supply. Properly accounting for the severity of VRE droughts is crucial for designing a weather-resilient renewable European power sector. Our analysis reveals the sensitivity of the optimal design of the European power sector to VRE droughts.

We analyze how VRE droughts impact optimal power sector investments, especially in generation and flexibility capacity. We draw upon work in progress by Kittel & Schill, which systematically identifies VRE drought patterns in Europe and provides a selection of relevant historical weather years representing different grades of VRE drought severity. These weather years serve as input for a capacity expansion model of the European power sector. In addition to weather years, we model different exchange scenarios for both electricity and hydrogen.

Results

Preliminary results illustrate how an imprudent selection of weather years may cause underestimating the severity of VRE droughts, flawing modeling insights concerning the need for flexibility, especially long-duration storage. Sub-optimal European power sector designs vulnerable to extreme weather can result. Using relevant weather years that appropriately represent extreme weather events, our analysis identifies a resilient design of the European power sector. Although the scope of this work is limited to the European power sector, we are confident that our insights apply to other regions of the world with similar weather patterns.

A binary expansion approach for the water pump scheduling problem in large and high-altitude water distribution networks

Denise Cariaga[1] (Speaker), Álvaro Lorca[2], Miguel F. Anjos[3]

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Keywords: Discrete Optimization, Water distribution networks, Water pump scheduling problem, Water-Energy Nexus, Nonlinear Optimization

Motivation

The water pump scheduling problem is to determine which water pumps will be turned on or off at each time period over a given time horizon for a given water distribution network. This problem has received considerable attention in mining and desalination due to the high-power consumption of water pumps and desalination plants, and the complicated dynamics of water flows and the power market. Motivated by this, in this paper determine the optimal operation of a desalinated water distribution network consisting of interconnected tanks and pumps that transport water to high-altitude reservoirs. The optimization of this process encounters several difficulties arising from: i) the nonlinearities of the equations for the frictional losses along the pipes and pumps, which make the problem a nonlinear mixed-integer model, and ii) many possible combinations of pressure head and flow rates, which quickly lead to high computational costs. These limitations prevent the problem from being solved in a reasonable computational time in water distribution networks with more than two pumps and reservoirs, as in many networks worldwide. Therefore, this research identifies challenges that remain unsolved in the current state of the art: How to solve the water pump scheduling problem for large and elevated water distribution networks in a reasonable time? How to efficiently represent the nonlinear nonconvex hydraulic equations in the water pump scheduling problem with desalination plants in the context of large and high-altitude water distribution networks? How does a dynamic electricity tariff affect the water pump scheduling problem in high-altitude water distribution networks?

Methods

In this research, we develop new optimization models for addressing the pump scheduling problem, aiming to efficiently handle existing nonlinearities while reducing the computational complexities of the original problem and ensuring an accurate representation of the involved physical phenomena. We devise three methodologies to tackle the nonlinearities present in the original problem, each differing in the final nature of the model, whether linear or nonlinear. We describe these three proposed models to assess the computational effectiveness of the binary expansion approach method compared to other classic approaches: the fixed flow model (FF), semi-linear model (SL), and the binary expansion approach model (BEA).

The first approach, FF, involves fixing the water flow value in the complex energy loss equation. The second approach, SL, linearises the binary and continuous products within the problem's constraints. The third alternative, BEA, linearises both the binary and continuous products and the complicating variables associated with water flow and pump power.

We optimize the water pump scheduling of high-altitude water distribution networks with multiple pumps and reservoirs using a discretized hourly time horizon and a dynamic electricity tariff. The high-altitude feature is crucial in our model.

Results

The three alternative optimization models were tested on three distinct and realistic high altitude water distribution networks from Chilean mining companies, employing the Gurobi 10 solver via Julia. These experiments entail the use of extensive and steep networks that send desalinated water from sea level up to the mountains (beyond 3000 meters above sea level) with up to 15 water pumps.

The binary expansion approach is applied to address the intricate hydraulic constraints of the model by segmenting certain variables into 2^N pieces. Given that the complicating constraints are nonlinear and nonconvex, solving the problem becomes inherently challenging. Nonetheless, through the binary expansion approach, we manage to reduce computational times while maintaining an optimality gap below 5%.

In most cases, the binary expansion approach performs better than the MINLP Gurobi solver with a high solution precision. The computational efficiency of the approach makes it possible to use it for hours or day-ahead operation, such as many types of electrical demand flexibility models that are relevant for the practical daily operation of real-world water distribution networks.

The altitude of a water network emerges as the parameter with the greatest impact on the solution time; that is, the greater altitude the network reaches, the faster the model operates, owing to the network's restrictive nature. Also, the total length of the pipes is only relevant when the network is short. The recommended number of partitions in the binary expansion approach is between four and six, depending on the network’s characteristics. Using more than ten partitions is not advisable, as computational times escalate rapidly with marginal changes in the optimality gap.

Electricity markets in a fully decarbonized economy

Frank Heinz[1] (Speaker), Reinhard Madlener[2]

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Keywords: Mean-reverting stochastic process, Time-dependent trend, Inverse Gamma Dynamics, Sustainable Energy Transition, Merit-order curve, Day-ahead market

Motivation

Renewable power generation produces at almost zero marginal costs and thus may reduce wholesale electricity prices to the extent that investors often do not obtain sufficient returns anymore. We quantify this so-called "merit-order effect'' and show that even in a fully decarbonized economy, storage and backup power offsets this effect, leading to an overall sufficient price level. Further, we show that the transition to carbon neutrality increases the price volatility. Both findings are robust and hold under a variety of different transition scenarios and assumptions.

Methods

We find this by modeling supply and demand separately, with positive, mean-reverting stochastic processes that feature time-dependent trend functions and positive, Inverse Gamma dynamics. By using the research on future supply and demand scenarios, this method enables an electricity price projection for the year 2050, the expected time of decarbonization. To this end, the model is first calibrated to day-ahead market data of the year 2019 and then, the merit order curve is transformed into a state that represents full decarbonization, in this step leveraging literature on the ongoing energy transition in Germany. The results finally are found with a numerical simulation. For integrating the stochastic differential equations, a Runge-Kutta-type scheme with convergence order O(h) is applied.

Results

We can show that under a wide range of assumptions, while on the one hand, we confirm the merit order effect, on the other hand, this is offset by other power generation assets in the future merit order curve like hydrogen re-electrification and others. Thus, the average electricity price continues to provide adequate returns for power generation assets. We can show as well that the volatility increases compared to the level today, both under the assumptions of elastic and inelastic demand, which provides concerns from the perspective of investors.