ENERDAY 2022

16th Conference on Energy Economics and Technology

"Legacy assets and infrastructures in the energy system transformation – Out with the old, in with the new?"

Book of Abstracts

30 September 2022
Dresden

Organising institutions

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We at SachsenEnergie are the regional performance leader in the energy industry, providing modern solutions spanning the areas of electricity, gas, heat, water, telecommunications, e-mobility and smart services to ensure the best quality of life in our region. Over 3,500 employees support widespread public services for the people and businesses in Dresden and the East Saxony region. As the dominant municipal utility company we are the designers of intelligent energy transformation and are steadily pushing towards the increase in renewable energies, investing in the development of local infrastructure and committing to future grids in order to enable security of supply for tomorrow.

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

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 16th ENERDAY Conference on Energy Economics and Technology,

on behalf of the Chair of Energy Economics (ee^2) at the Technische Universität Dresden and the Workgroup for Economic and Infrastructure Policy (WIP) at Berlin Institute of Technology (TU Berlin), it is our pleasure to welcome you to this 16th edition of the ENERDAY, the International Conference on Energy Economics and Technology, with this year's focus on *"Legacy assets and infrastructures in the energy system transformation - Out with the old, in with the new?"*.

After a successful digital conference last year, we decided to meet again in person (in combination with a hybrid format) as we intend to support networking and fruitful exchanges. Furthermore, we are hosting the event at the University campus. The exceptional date in September, traditionally the ENERDAY is held in April, offered the opportunity to use the lecture halls during semester holidays.

In writing this foreword, the public debate is aware of questions regarding the energy crisis, providing plenty of material for discussion. While dips in electricity consumption and carbon emissions resulting from the Covid-19 crisis seem to be short-term in nature, the current energy crisis in Europe could impact the long-term trajectory of the energy system, especially in the context of decarbonisation efforts. Even current measures targeting a short-term horizon should not lose sight of the long-term objectives, primarily as a significant potential exists for the targeted deployment of investments toward the acceleration of the transformation of the economy towards carbon neutrality. The transformation of the energy system largely relies on facilitating the development of sustainable assets and infrastructures across the energy value chain. The development and repurposing of legacy infrastructure and investments in sustainable alternatives determine path dependencies that will influence the trajectory of the energy system for decades to come. The decision as to which approach is most suitable and effective depends on numerous factors. The current discussions around the EU taxonomy of sustainable infrastructures highlight differences in member states and stakeholders' opinions and policy objectives.

Moreover, the current Russia crisis requires a reassessment of current energy supply dependencies. The competition between different transformation pathways as well as path-dependent restrictions requires a holistic view toward evaluating the role of energy assets and infrastructures in a system-wide context and a detailed analysis of the interdependencies between them. Against this backdrop, it is important to renew and deepen discussions on overarching issues and challenges associated with deep decarbonisation pathways, e.g., security of supply in the face of nuclear and coal power phase-outs and the role of disruptive technologies such as hydrogen as a means of scaling decarbonisation in the heating and transportation sectors. Last but not least, new climate policy measures merit particular attention and their sufficiency in reaching carbon targets in Germany, Europe, and globally.

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

The 16th ENERDAY - Conference on Energy Economics and Technology is organised as a face-to-face conference with the possibility of hybrid participation reserved for a few selected sessions. The ENERDAY provides a platform for discussing topics related to energy systems, markets, and policies, focusing on the role of existing energy assets and infrastructures in the context of the energy system transformation. Empirical analyses, modelling approaches, best practice examples, and policy and market design evaluations are of particular interest. Furthermore, research on the economics of deploying new technologies is also relevant. We hope this year's ENERDAY will provide a platform for strengthening the dialogue between those involved in economic and technical fields and serving to bridge the gap between practice and theory.

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

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

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

Dominik Möst and Christian von Hirschhausen
& ee^2 organizing committee

Instructions for joining the online hybrid sessions

Hyrbid Session Room in Zoom

This year's conference includes two hybrid sessions (room CHE/S91 and CHE/S89) with presence and online participants.

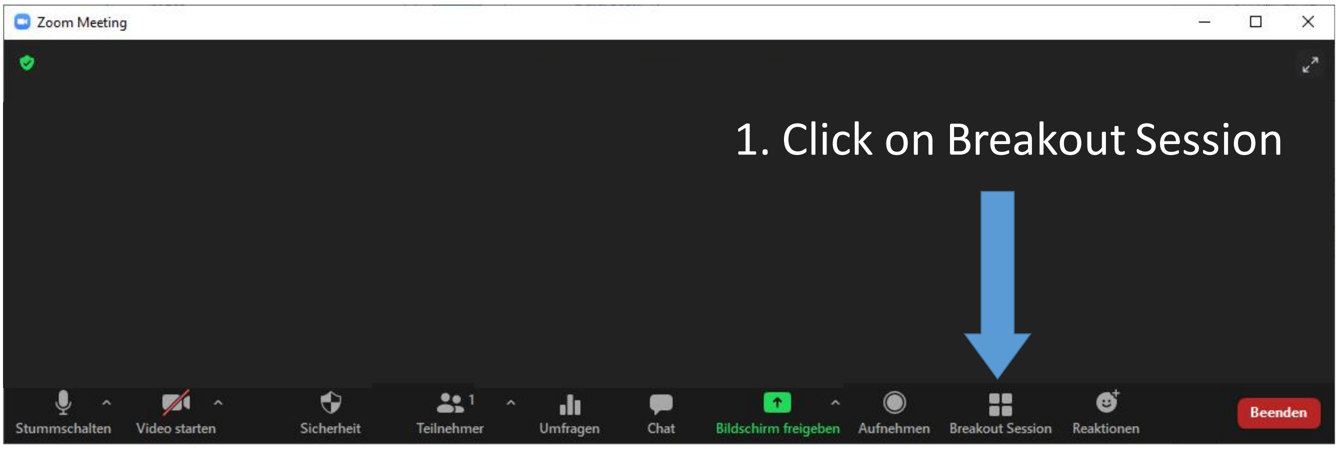
The hybrid session is being held via the video conference software Zoom. It is recommended to download the software / app. For a seamless experience, it is recommended that you use the latest desktop version of Zoom (https://zoom.us/download).

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

Zoom-Meeting beitreten
https://tu-dresden.zoom.us/j/67981962332?pwd=VFFwUmZnYUdnWWJzQVFUQ2JVQ0JYQT0

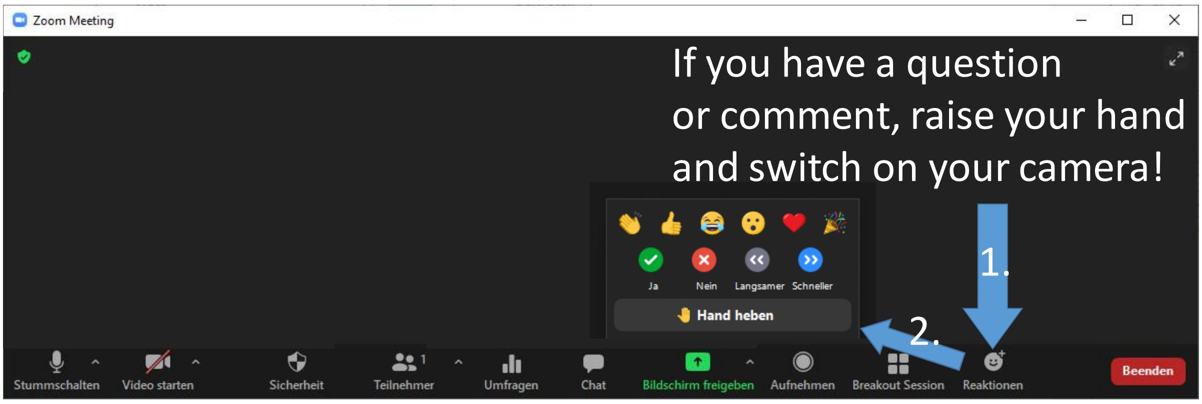
Meeting-ID: 679 8196 2332
Kenncode: 4?cBeRi*

To participate in the two hybrid sessions, please enter:
- The main room for CHE/S91
- The breakout room for CHE/S89



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

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



Conference Program – Friday, 30 September 2022

Pre-Conference-Dinner	**Thursday, 29 September 2022, 6:00 pm**	Restaurant Campus, Hübnerstraße 13, 01069 Dresden
Conference	**Friday, 30 September 2022, 8:00 am**	Chemie-Gebäude (Link zum Campusnavigtor)

8:00	Registration, Coffee & Tea			
8:30	**Opening Address** (Room: CHE/S91, hybrid) Prof. Dr. Dominik Möst, TU Dresden			
9:00 - 9:45	**Keynote Talk** (Room: CHE/S91, hybrid, Chair: Prof. Dr. Dominik Möst, TU Dresden) **Use of energy scenarios at a TSO in Germany – recent developments and opportunities for research** Martin Klein, 50Hertz Transmission GmbH			
9:45	**5 minutes for change of room**			
	Parallel Session 1			
9:50 - 10:50	**Energy security** Room: CHE/S91, hybrid Chair: Christoph Kost	**Flexibility and energy management systems** Room: CHE/S89, hybrid Chair: Steffi Misconel	**Low carbon energy transformation pathways I** Room: CHE/183 Chair: Hendrik Scharf	**Advanced optimisation in energy economics** Room: CHE/184 Chair: Felix Schmidt
9:50	**The impact of energy security on a German energy system by 2030 and 2045 and the role of heat pumps** Christoph Kost, Fraunhofer ISE	**Assessing demand response potentials in the climate-neutral German power system** Johannes Kochems, Deutsches Zentrum für Luft- und Raumfahrt e. V.	**Developing low carbon scenarios for the European energy system: Exploring the role of renewable hydrogen in a sector-coupled European energy system towards 2050** Konstantin Löffler, TU Berlin	**Hybrid Optimization - The impacts of extreme climate conditions on the future European electricity system** Maximilian Bernecker, BTU Cottbus-Senftenberg
10:10	**European gas scenarios for the upcoming winter** Andreas Schroeder, ICIS	**Operational optimization of existing energy systems** Arne Martin, Fraunhofer IOSB-AST	**How does an early coal exit impact Germany's natural gas dependence? Implications of the current coalition contract for the power sector in 2030** Hendrik Scharf, TU Dresden	**Benders decomposition for energy system planning with multiple climatic years** Felix Schmidt, DIW Berlin
10:30	**Natural gas markets between energy security and energy transition** Dzhanneta Medzhidova, Higher School of Economics	**How flexible electrification integrates fluctuating renewables** Leonard Göke, TU Berlin	**Is Germany on the right track to achieve 2030 climate and energy targets?** Smaranda Sgarciu, BTU Cottbus-Senftenberg	**Multistage modelling approach to optimize investment and operational decisions in electricity markets with a high level of detail** Laura Torralba-Diaz, IER Stuttgart
10:50	**Coffee & tea break**			

Parallel Session 2				
11:15 - 12:15	**Hydrogen markets and market integration** Room: CHE/S91, hybrid Chair: Lauritz Bühler	**Sector coupling and market innovation** Room: CHE/S89, hybrid Chair: Hannes Hobbie	**Low carbon energy transformation pathways II** Room: CHE/183 Chair: Lucas de la Fuente	**Statistical approaches for energy economics** Room: CHE/184 Chair: Felix Jakob Fliegner
11:15	**The role of hydrogen in a sector-integrative European energy system model** [cancelled] Christoph Schmitz, r2b energy consulting GmbH	**Suggestions for improvements in TSOs regulation to foster energy innovation** Eva Marie Kurscheid, TenneT TSO GmbH	**Policy effects and implications on the future low-carbon energy and transportation sector** Karlo Hainsch, TU Berlin	**Shazam for the power sector - Application of Fourier transformation to unravel energy portfolio intermittency in the European power system** Felix Jakob Fliegner, TU Dresden
11:35	**Green hydrogen - How grey can it be?** Johannes Brauer, MINES ParisTech	**Investments in coupled energy sectors and market pricing** Jonas Egerer, FAU Erlangen-Nürnberg	**Premature nuclear retirements and nuclear decommissioning funds: Insights from New York** Muhammad Maladoh Bah, University of Basel	**Simulation of Germany's security of supply: long-term forecasting of electric load profiles using machine learning** Benedikt Prusas, HS Düsseldorf
11:55	**Global hydrogen trade - A single-period mixed complementary model for the global hydrogen market in 2030** Leonhard Dux, TU Berlin	**Power sector effects of different supply chains for green hydrogen in Germany** Dana Kirchem, DIW Berlin	**Nuclear bias in energy scenarios – A review and results from an in-depth analysis of long-term decarbonisation scenarios** Björn Steigerwald, TU Berlin	**The financialization of the European futures market for carbon emission allowances** Tom Dudda, TU Dresden
12:15 - 13:30	**Lunch break**			
13:30 - 14:15	**Keynote Talk** (Room: CHE/S91, hybrid, Chair: Prof. Dr. Christian von Hirschhausen, TU Berlin, and DIW Berlin) **Flexibility in infrastructure markets - A multi-level perspective** Prof. Steven A. Gabriel, PhD, University of Maryland, and NTNU Trondheim			
14:15	**5 minutes for change of room**			

Parallel Session 3				
13:15 - 14:30	**Energy efficiency and environment** Room: CHE/S91, hybrid Chair: Maximilian Happach	**Renewables in transportation systems** Room: CHE/S89, hybrid Chair: Bjarne Steffen	**Hydrogen and impact on electricity transport infrastructure** Room: CHE/183 Chair: Martin Lieberwirth	**Renewable auctions and financing** Room: CHE/184 Chair: Lisa Lorenz
14:20	**Ecological footprint-environmental regulations nexus: The case of the Union for the Mediterranean** Burak Erkut, Bahçeşehir Cyprus University	**The competition of zero-emission vehicle technologies in road freight** Bjarne Steffen, ETH Zurich	**Hydrogen electrolysis and electricity networks – What to support, what not?** Friedrich Kunz, TenneT TSO GmbH	**Renewable procurement auctions and default: pre-qualification requirements** Silvester van Koten, CERGE-EI Prague
14:40	**Municipal networks for mutual support: How can this contribute to the implementation of energy efficiency measures?** Uta Burghard, Fraunhofer ISI	**Reviewing comparative life cycle assessments for battery electric vs. internal combustion engine vehicles for passenger cars** Christina Kockel, RWTH Aachen University	**Benefits of a hydrogen network in Europe with repurposed gas pipelines** Fabian Neumann, TU Berlin	**Market-financed large-scale solar power without support schemes?** Anurag Gumber, ETH Zurich
15:00	**Determinants of energy intensity in Turkish manufacturing industry** Umut Erksan Senalp, Trakya University	**The role of public investment in building up a public electric vehicle charging grid** Marie-Louise Arlt, LMU München	**Decarbonizing the industry sector and its effects on electricity transmission grid operation – implications from a model based analysis for Germany** Martin Lieberwirth, TU Dresden	**Preferential treatment in renewable energy auctions: an analysis of the reference yield model & German wind auctions** Prokop Čech, Jan Evangelista Purkyně University
15:20	**Coffee & tea break**			
15:45 - 16:30	**Keynote Talk** (Room: CHE/S91, hybrid, Chair: Prof. Dr. Dominik Möst, TU Dresden) **Technical pathways to and economic issues with decarbonizing electricity systems** Prof. Ramteen Sioshansi, PhD, The Ohio State University			
16:30	**5 minutes for change of room**			

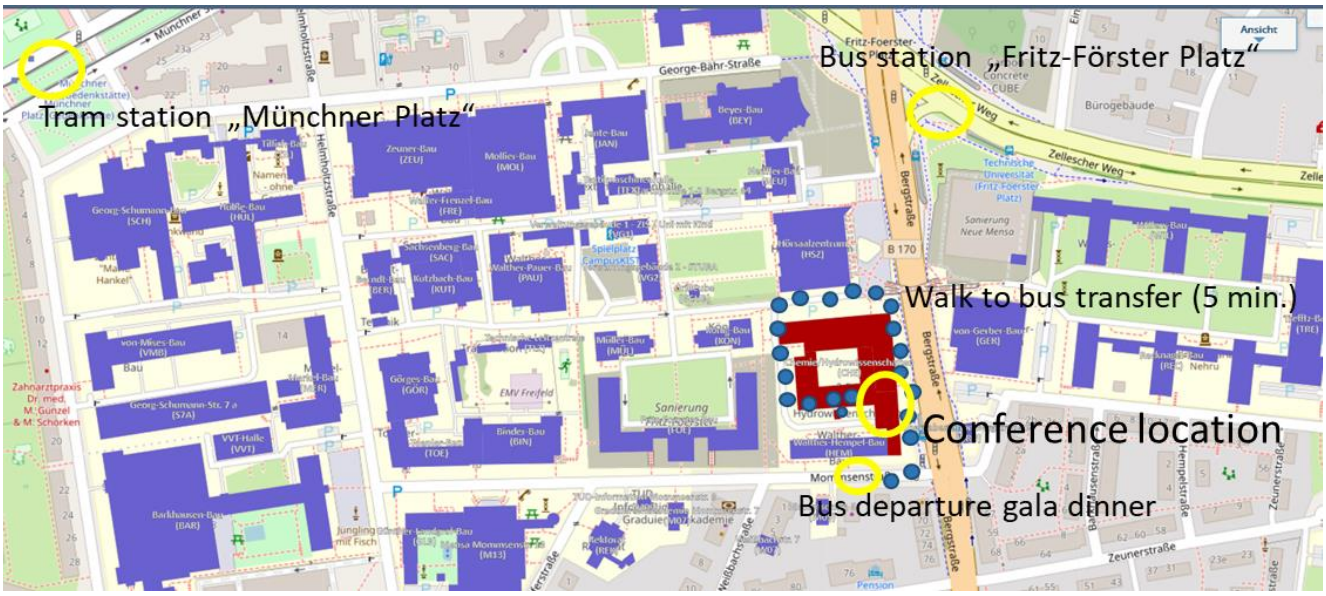
Parallel Session 4				
16:35 - 17:35	**Hydrogen and hydrogen-based commodities** Room: CHE/S91, hybrid Chair: Philipp Hauser	**Renewables in developing countries** Room: CHE/S89, hybrid Chair: Constantin Dierstein	**Sector integration of heating and cooling appliances** Room: CHE/183 Chair: Carl Philipp Anke	**Decentralised energy systems** Room: CHE/184 Chair: Jens Maiwald
16:35	**Opportunities for the German gas grid by using synthetic fuels from an energy system perspective** Felix Kattelmann, IER Stuttgart	**ENERWARD: Winners of the best Diploma / Master's thesis award** Alexander Michael Floren Malte Karitzky	**Optimisation of costs, carbon emissions and thermal comfort in a building-level energy system model** David Huckebrink, Ruhr-University Bochum	**Optimal economic and environmental design of multi-energy islands** Tom Terlouw, Paul Scherrer Institut
16:55	**Amonia and its role in the European hydrogen market ramp-up** Philipp Hauser, VNG AG	**South Africa's energy transition – Unravelling its political economy** Jonathan Hanto, Europa-Universität Flensburg, TU Berlin	**Sector integration with residential heat pumps: the impact of building characteristics and user behaviour** Evelyn Sperber, Deutsches Zentrum für Luft- und Raumfahrt e. V.	**Local sustainable communities: consumer involvement for sustainable development in energy transition** Matthias Maldet, TU Vienna - Energy Economics Group
17:15	**Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities** Michael Moritz, Uniper	**How population migration affects carbon emissions in China: Factual and counterfactual scenario analysis** Yan Bu, Dalian University of Technology	**Load shifting of distributed cross-sectoral energy systems in economically optimised operation** Sebastian Berg, Fraunhofer UMSICHT	**Peer-to-peer trading in decentral energy markets with pro-active consumers** Jens Maiwald, HS Zittau/Görlitz
17:35	**End of parallel sessions**			
18:00	**Bus transfer to gala dinner (departing from Mommsenstraße)**			

Gala Dinner Official closing event and award ceremony	**Friday, 30 Sept 2022, 19:00**	**Restaurant Lingnerterrassen** https://lingnerterrassen.de/ Bautzner Str. 132, 01099 Dresden

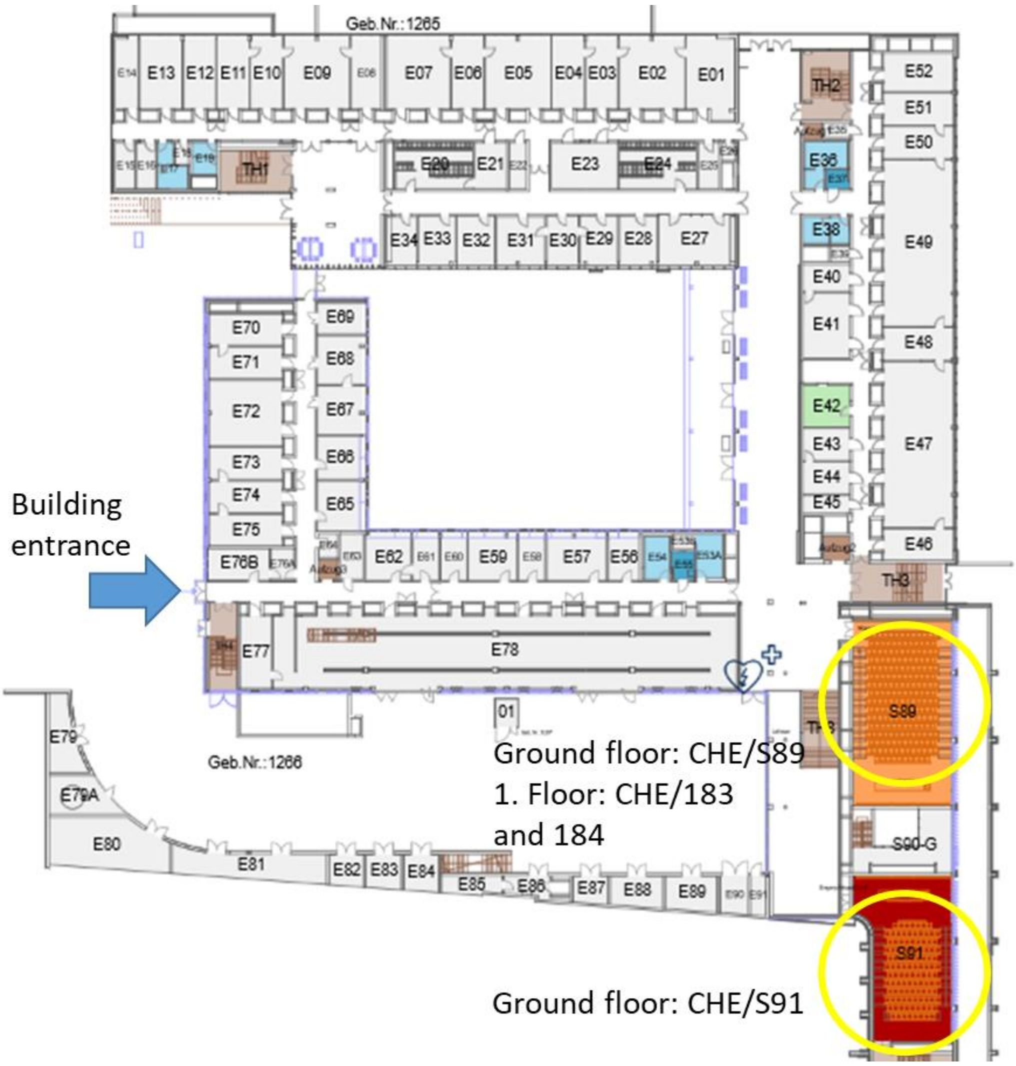
23:00	**Bus transfer to the central train station (departing from the gala dinner location)**

Conference location on campus

Campus Navigator: https://navigator.tu-dresden.de/karten/dresden/geb/che/@13.727206,51.029025,17.z



Conference rooms in Building Chemie



Content

Keynote 9:00 – 9:45

Room: CHE/S91, hybrid
Chair: Prof. Dr. Dominik Möst

Use of energy scenarios at a TSO in Germany – recent developments and opportunities for research

Martin Klein [1]

[1] *50Hertz Transmission GmbH*

Session 9:50 – 10:50
Energy security

Room: CHE/S91, hybrid
Chair: Christoph Kost

The impact of energy security on a German energy system by 2030 and 2045 and the role of heat pumps

Christoph Kost, Fraunhofer ISE

European gas scenarios for the upcoming winter

Andreas Schroeder, ICIS

Natural gas markets between energy security and energy transition

Dzhanneta Medzhidova, Higher School of Economics

The impact of energy security on a German energy system by 2030 and 2045 and the role of heat pumps

Christoph Kost [1]

[1] *Fraunhofer ISE, christoph.kost@ise.fraunhofer.de*

Keywords: energy security, energy modeling, climate neutrality, natural gas, price

Motivation

The recent energy crises of natural gas supply in Europe caused by the Russian invasion of the Ukraine have put a spotlight on the interdependence between the energy transition towards climate neutrality and security of supply of conventional fuels from to today until 2030 and 2035. This paper therefore assesses the impact of a sustained energy crisis and resulting higher fossil resource prices, in particular for natural gas and oil, and options for dedicated measure to reduce the dependence on imports in particular of natural gas and oil. The results are based on a common scenario approach in the ARIADNE Kopernikus project and are calculated by using the energy system REMod which was used in several important scenario studies recently. There are multiple studies analyzing the German energy transformation considering its national CO2 reduction goals, i.e. with the target of net-zero emissions in 2045 (Brandes et al. 2021; Luderer, Kost, and Dominika 2021; Prognos, Öko-Institut, and Wuppertal-Institut 2021). However, all of them have been published before the current energy crisis in 2022.
A second detailed analysis of this paper is the role of heat pumps as they are a central substitution technology of natural gas in the building sector of Germany. As electricity demand by heat pumps will grow, this demand will be analyzed in a statistical analysis of the operation of heat pumps.

Methods

The German energy system model "REMod" was developed at the Fraunhofer Institute for Solar Energy Systems ISE to model transformation pathways of the German energy system within a given CO2 reduction pathway (Henning and Palzer 2014; Palzer and Henning 2014; Palzer 2016; Sterchele 2019). REMod uses a mixture of simulation and optimization: it simulates the energy system on an hourly basis and optimizes the accumulated costs (CAPEX and OPEX). The focus of REMod is on the detailed description of sector coupling, i.e. the use of renewable energy in the demand sectors industry, buildings and transportation including interactions between these sectors. The simulation includes all demand sectors (industry, transportation, buildings) as well as coupling of the sectors. The optimization determines yearly additions in the available capacity for multiple power plant types and energy conversion technologies as well as exchange of technologies in the demand sectors. This approach of simultaneously optimizing all sectors of the energy system distinguishes REMod from other energy system models and enables the analysis of mutual influences of the different sectors.

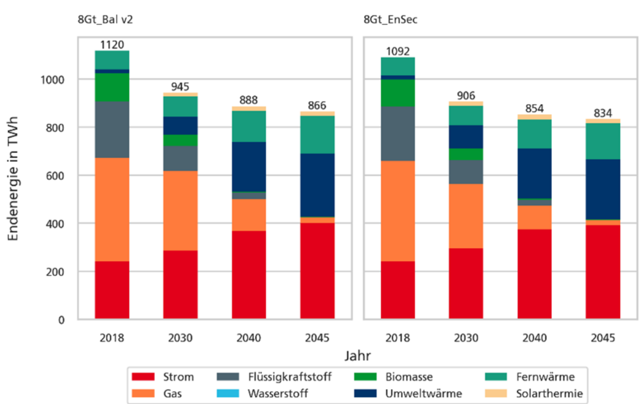
By simulating the energy system on a yearly base from today to 2050 considering five years with differing meteorological conditions, the model ensures that the energy demand is always met and supply reliability is guaranteed. Moreover, the optimization of the power plant park and the technology stock in each consumption sector by REMod enables a cost optimal transformation path of the entire energy system.

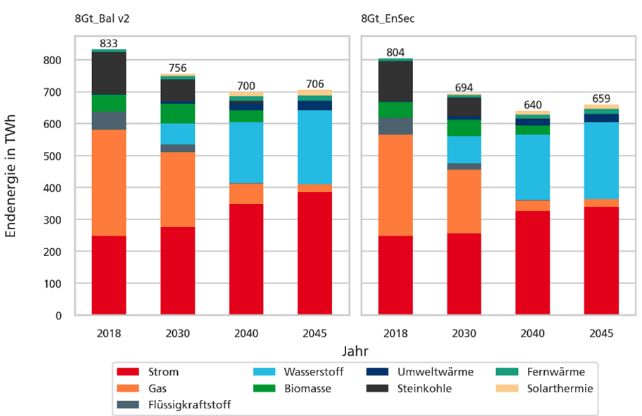
In this scenario approach the volume of consumed natural gas was given a higher price compared to previous studies. The imports have been carefully assessed in this study.

Results

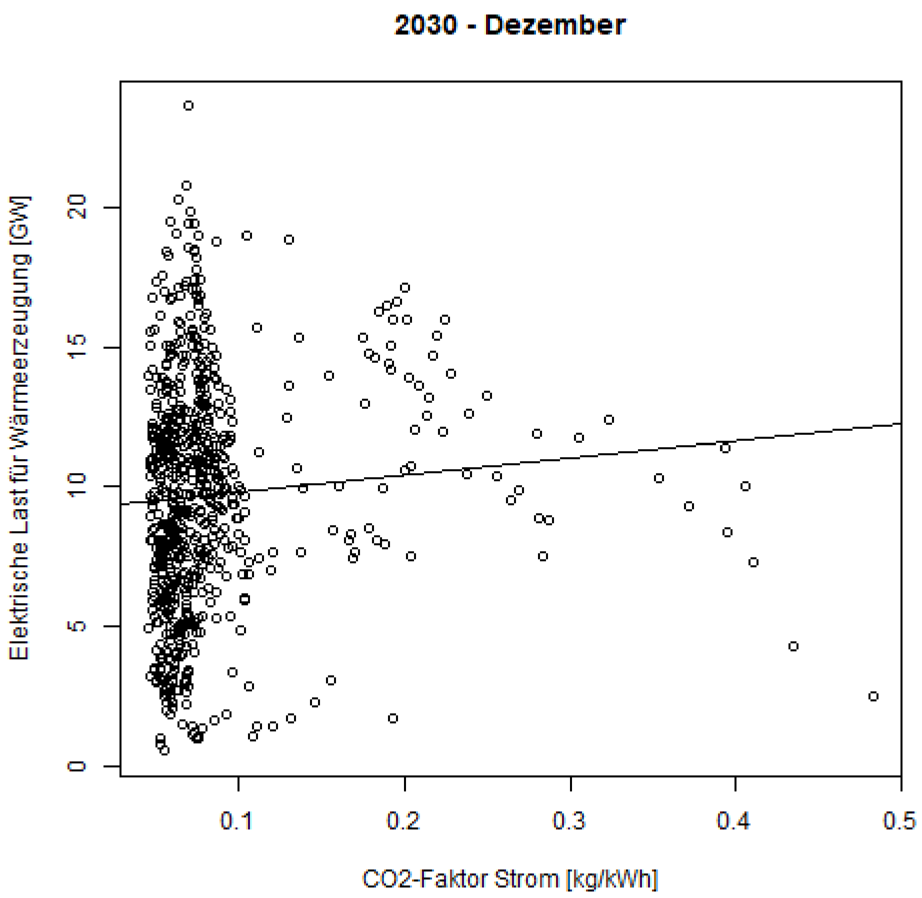
The results can be summarized as follows:

A scenario with lower gas price and less restriction on availability also has to reduce the natural gas consumption by 2030 and 2040 strongly. In the case of energy security this reduction is higher (about 25%) in 2030. Final energy is reduced in the building sector and industrial sector by 5 to 10%.The reduction in final energy demand is mainly a direct reduction of natural gas whereas the rest of the energy carrier remain stable (with small increase of direct electricity consumption and more heat pumps). The following two graphs show the final energy demand development until 2045 in the case of an energy security scenario compared to a "normal" world (see Figure 1 and Figure 2).





The results on the second analysis shows a very interesting result on the operation of heat pumps. In the following graph the electrical load of all heat pumps in Germany in each hour in December 2030 is plotted with the CO2 factor in the electricity mix. The results show that heat pumps are operated just in a few hours with a high CO2 factor which means that still conventional power plants have to be operated for the use of heat pumps (for example in December with low wind availability). But in many hours in December the CO2 factor in the electricity mix is low. That means that heat pumps use a high share of renewable electricity during many hours in December. The final analysis will show more months and more years to compare this phenomenon in different weather conditions.



The work on this paper was supported by the BMBF Ariadne project with sign 03SFK5D0.

European gas scenarios for the upcoming winter

Andreas Schroeder [1]

[1] *ICIS, andreas.schroeder@icis.com*

Keywords: natural gas, LNG, Russia, European Union

Motivation

Global gas markets have been in turmoil in recent times undergoing significant changes in the wake of the Ukraine-Russia conflict. LNG is strengthening its role in Europe replacing Russian gas as a primary fuel supplier. Gas storages are strongly regulated and key to bring Europe over a cold winter. Gas demand reductions will contribute to gain independence from Russian gas imports with the exact amount of them still to be gauged.

Methods

We analyse scenarios of market changes and give an outlook on implications for market prices, gas flows and security of supply. The analysis draws on weather-driven consumption forecasts and a European gas market optimization model with daily resolution looking two years ahead. The model optimizes European LNG versus pipeline import and it considers weather effects on demand, infrastructure capacity constraints, storage obligations, long-term contracts, capacity bookings as well as supply cost. The base scenario is represented by Russian supplies limited to contractual obligations while a second scenario studies the impact of a complete halt in Russian supplies. The analysis takes into consideration different weather forecasts as well as demand response.

Results

Our findings point to the limited displacement potential of Russian gas imports. If Russian gas is replaced by LNG, it will come at an additional cost. Also, we find that the new EU storage regime is feasible and ensures the security of supply in a cold winter scenario. The role for demand reduction / rationing is crucial in achieving independence from Russian gas imports.

Natural gas markets between energy security and energy transition

Dzhanneta Medzhidova [1]

[1] *Higher School of Economics, dmedzhidova@hse.ru*

Keywords: energy security, energy transition, natural gas market, LNG market, asset specificity

Motivation

Climate change mitigation remains one of the international community's most acute problems, with the energy sector undergoing the most significant transformation. V. Smil identifies four stages of the energy transition. While advanced economies are on the fourth one, shifting from fossil fuels to renewable energy sources, the developing part of the world is still mainly on the third one, moving from coal and oil to natural gas. In the changing environment, natural gas has two roles as a backup and a transition fuel, depending on the level of economic development of a country and the structure of its primary energy consumption.

The energy transition process has major implications for natural gas markets. Firstly, global consumption growth in the medium and long-term periods will contribute to LNG market development. Secondly, highly specific assets (pipelines and LNG terminals) are at risk of becoming stranded. However, it might happen due to political decisions and not economic rationale. Thirdly, we witness the transformation of supply routes, which causes transportation costs to grow, and could catalyze further regionalization of natural gas markets. Finally, energy transition and energy security are often opposed to each other. We focus on the last issue and analyze this dichotomy in different regional natural gas markets using the new institutional economics methodology. Our research consists of an introduction, three main parts and a conclusion: the first one highlights principal differences between regional markets; the second part analysis the 2021 energy crisis from the grounds of energy security and energy transition; the third one provides an analysis of the current situation and the future of the regional gas markets.

Methods

Nowadays, major regional markets are located in North America, Europe and the Asia Pacific. These markets differ in many ways, including the level of liberalization, preferable type of transportation (tankers or pipelines), and institutional features (contract duration, number of large hubs, price formation mechanism). Immanent characteristics, including geological and geographical ones, also depend on the region. We believe that those differences, along with external factors (geopolitics and economic development), broadly define the energy transition process that has already been undermined by post-pandemic recovery, accompanied by fossil fuels (including coal) consumption growth.

Our study incorporates an analysis of the energy crisis that happened in 2021. Highly specific assets often create incentives for opportunistic behaviour, which used to be excluded via long-term contracts between suppliers and buyers. According to the transaction costs theory, the optimal mechanism of governance, in this case, is a hierarchy (i.e. a bilateral monopoly). Nevertheless, the European natural gas market regulation is incompatible with the theory. After the market liberalization, implemented in the EU through energy packages, natural gas prices tend to be lower; however, they become more volatile in times of crisis. Furthermore, the 2021 crisis has illustrated that energy transition could have negative externalities for energy security.

Results

Energy security is commonly understood as energy availability, accessibility and affordability, and this composition is still relevant. In addition, supply and prices become urgent challenges with the intensification of geopolitical tensions between major players in the European market – the EU and the Russian Federation. We examine the new European plan on phasing out Russian natural gas in the context of energy security and its consequences for other regional markets. Although historically, Russia has developed its pipeline system in the European direction, LNG exports was launched in 2009, and for now, Russia is one of the largest LNG exporters globally. We identify crucial obstacles for Russian natural gas exports both via pipelines and tankers in the current conditions. Rerouting significant volumes and the EU demand can support high gas prices for a period of market transformation, at least. Furthermore, consequences will include new institutional arrangements, reinforced if natural gas is widely accepted as a ‘green’ source of energy.

Some of the expected results are mentioned in different parts of this abstract, as they are linked to particular cases (for example, to the 2021 crisis), which are analyzed using a particular methodology. In conclusion we define the future of regional gas markets, their institutional characteristics and key implications for energy transition and energy security.

Session 9:50 – 10:50
Flexibility and energy management systems

Room: CHE/S89, hybrid
Chair: Steffi Misconel

Assessing demand response potentials in the climate-neutral German power system

Johannes Kochems, Deutsches Zentrum für Luft- und Raumfahrt e. V.

Operational optimization of existing energy systems

Arne Martin, Fraunhofer IOSB-AST

How flexible electrification integrates fluctuating renewables

Leonard Göke, TU Berlin

Assessing demand response potentials in the climate-neutral German power system

Johannes Kochems [1]

[1] *Deutsches Zentrum für Luft- und Raumfahrt e. V., johannes.kochems@dlr.de*

Keywords: demand response, demand side management, potentials, power market modeling

Motivation

The energy transition demands for increasing flexibility to level out fluctuations from variable renewable generation units. Demand response is one of the options to provide this flexibility. A comprehensive meta-analysis on technical demand response potentials for Germany and a clustering of these potentials have been carried out in prior analyses [1, 2]. Though there are some economic demand response potential estimates for Germany [3, 4], an assessment of potentials in a power system that is to be way faster decarbonized and thus demands for rapid flexibility contributions is lacking so far. The contribution shall close this research gap.

Methods

For studying the demand response potential for Germany, the modelling cosmos POMMES is used. POMMES itself consists of an extensive and transparent open data collection and processing routine pommesdata (https://github.com/pommes-public/pommesdata), an investment model pommesinvest (https://github.com/pommes-public/pommesinvest) in order to determine a capacity expansion pathway and a dispatch model pommesdispatch (https://github.com/pommes-public/pommesdispatch) to study the detailed hourly dispatch of flexible resources for snapshot years. The linear investment and dispatch model build on the open framework oemof.solph (https://github.com/oemof/oemof-solph). They can be characterized as linear fundamental models for the Germany day-ahead market, also considering price effects of cross-border exchange with neighbouring countries. For modelling demand response, a linear model representation of load shifting and shedding is used which is based on [5] and has been contributed to the framework by the author. Demand response parameterization is taken from a meta-analysis of technical demand response potentials in which values for capacity-related, time-related and cost-related parameters have been collected from 30 studies [2] and bundled to clusters [1].

Results

It can be found that demand response potentials behave very sensitive to their cost and parameter estimates as well as the parameterization of the remaining flexibility portfolio. In case of comparatively cheap power storage options, only limited demand response potentials are utilized. Given a high commodity price level and large price spreads based on supply scarcities, especially for natural gas due to the Ukraine war, both load shedding and load shifting options are chosen by the cost-minimization model. In future work, sensitivities shall be studied in more detail and also, the micro-economic rationales shall be assessed using the agent-based power market model AMIRIS and building onto [6].

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Operational optimization of existing energy systems

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Keywords: optimization, operational planning, energy management systems, gas reduction, utilities

Motivation

Due to recent geopolitical events it became even clearer that the optimal usage of the available energy is indispensable for all participants in the energy market. This optimal usage of controllable equipment is one of the key tasks of energy management systems (EMS). Some EMS can implement the operation management of controllable equipment through interfaces to an optimization environment. Recently, EMS are also used to optimize smaller energy systems, e.g. living quarters [1]. Thereby the operation of the considered energy system is optimized to a certain objective. Regardless of the size of the energy systems, the optimization often attempts to determine the operation with lowest costs. Purchasing electrical energy from the spot market with high price spreads leads to a high potential for cost reductions, see Figure 1. For a resilient planning under uncertain price conditions an intelligent EMS should be able to adapt the objective, e.g. to reduce the natural gas consumption. The minimization of natural gas purchase may be used in combination or instead of the already described minimization of costs. As it can be seen in [2] the use of natural gas was a cheap alternative to the use of electricity. Therefore, the optimization of the operation management recommended using natural gas, since it could not anticipate the sharp increase and the uncertainty related to the use of natural gas today. Therefore, arguments can be found for using a different objective instead of minimizing costs. Those different target functions include the minimization of CO2-emissions, maximizing self-consumption and/or maximizing self-supply.

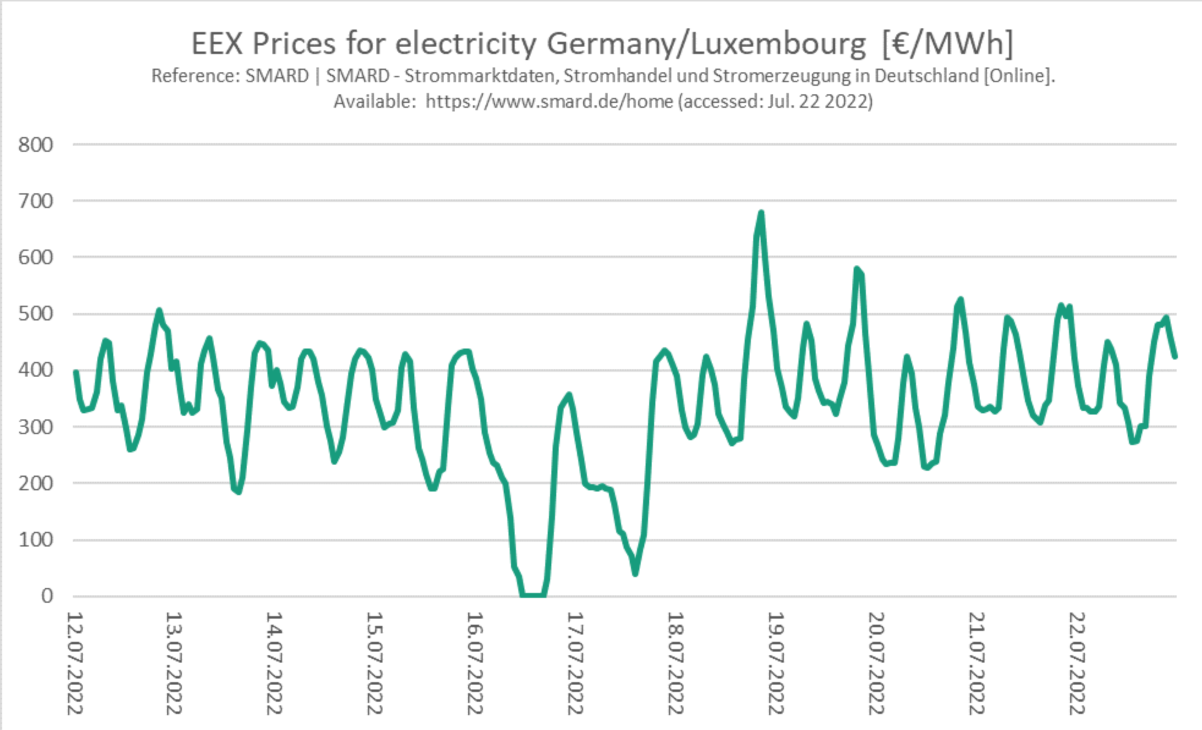

Figure 1

Methods

To determine the optimal operation of controllable assets a mixed integer linear optimization model is used as part of an energy management system. Within this proposal the flexibility of optimization models for resource planning and the adaptability to different optimization objectives is described. If the economical aspect is not the most important goal to be achieved, the target function could be adjusted to CO2 minimization [3]. Especially in the view of the current geopolitical situation, several energy systems of German utilities were analysed for their potential to reduce natural gas consumption. All assets of the utilities are modelled in the resource-planning tool of an energy management system. The technical restrictions of the assets such as efficiencies, minimum operating and shutdown times, economical parameters such as subsidies and operating costs as well as the interaction between the assets are considered in the planning process. Figure 2 shows an example of parameters and variables that could be considered for the possible boundary conditions of optimization models for power plant and resource scheduling. For the proposed analysis the asset parameters of the optimization model were not changed. The analysis only considers assets and sources (electricity, gas, oil, district heat, steam) that are already within the original cost optimal optimization model. To generate the optimal operation schedule for the assets with the minimal use of natural gas in a cost-minimal manner, the purchase price of the natural gas has been increased. This makes the purchase less viable, but still allows the optimization model to use natural gas. This is necessary to meet the heat and electricity demands.

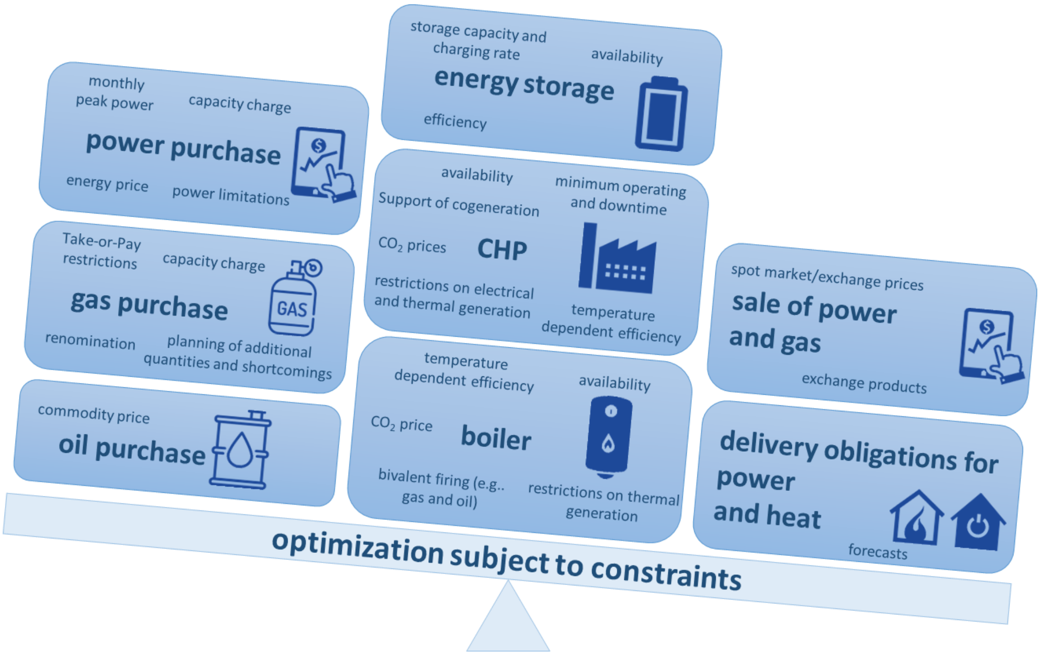

Figure 2

Results

The analysis of the possible natural gas reduction has been done with EMS-EDM Prophet® [4], an energy management system, that allows the management of time series, metering points and assets and includes a resource-planning tool based on optimization software. The cost optimal (reference) operation of four German utilities were compared to the gas minimal (alternative) operation for one month in the heating period. The potential natural gas reduction of the investigated utilities varies between 0 % and 62 %, see Figure 3. For one of the utility companies no reduction was possible because it already used the full potential of all non-gas driven assets and only used gas driven assets to provide heat in the reference case. Two of the investigated utilities achieved a possible gas reduction between 30 % and 50 % while one achieved the aforementioned 62 %. This high amount of reduced natural gas purchasing is mainly possible thanks to an alternative power plant, which doesn't use natural gas to provide district heating. Apart from this exception, the reduction is mainly achieved by using assets that generate heat by using electricity to substitute the heat from gas-driven assets. Additionally, the production of electricity through natural gas was reduced. Therefore, assets such as gas turbines, where used less. The three utilities, where a reduction of natural gas was possible, increased the electricity purchase and decreased the electricity delivery to the spot market. The costs for the alternative operation mode are significantly higher. In general, it has been found that assets that produce heat from other sources then natural gas have been prioritized. In conclusion, the adaptability of existing resource-planning models and an easy to realize benefit of optimization models in energy system planning was shown.

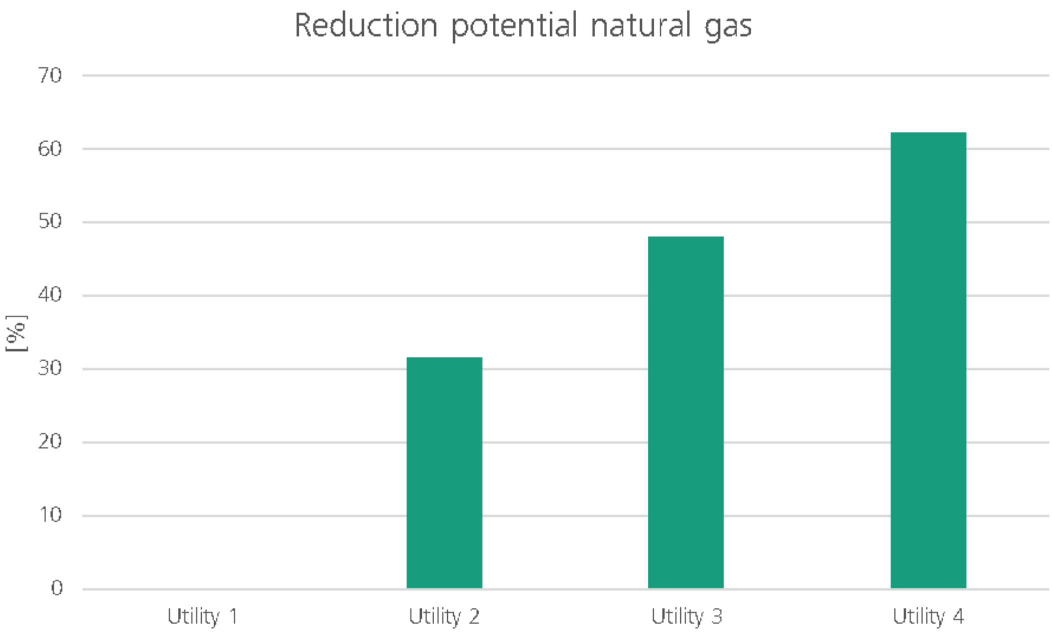

Figure 3

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How flexible electrification integrates fluctuating renewables

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Keywords: macro-energy systems, sector integration, decarbonization, flexibility

Motivation

Supply and demand for electricity will play a pivotal role in the transformation towards an energy system that achieves the targets of the Paris Climate Agreement.
On the supply side, wind and solar must replace generation from fossil fuels, but despite substantial decline in levelized cost, integration of wind and solar remains challenging. Especially at high shares, fluctuating renewable require complementary technologies, like storage, carbon neutral thermal plants, or transmission infrastructure, to provide flexibility.
At the same time, decarbonization will also have a profound effect on the demand for electricity. Mitigating emissions beyond the power sector in heating, industry, and transport requires renewable electricity as a primary source of energy, either directly or indirectly using synthetic fuels produced from electricity. Both options entail close integration with the power sector, but differ in how they affect the total level, the pattern, and the elasticity of electricity demand - all factors decisively shaping the need for flexibility in renewable systems.
In conclusion, the provision and need for flexibility is shaped by interactions and synergies of both, electricity supply and demand. Yet, existing analyses of decarbonized power systems are predominantly focused on the supply side. Typical studies assess the interplay of fluctuating renewables with different storage systems, thermal power plants, and interconnection, but the assumed level, profile, and elasticity of demand are based on historical data and do not reflect decarbonization beyond the power sector. Other studies do consider changing demand, but still assume it to be an exogenous factor, focusing their analysis on the supply side.
Extending the existing literature, this paper transcends the focus on supply-side options and investigates how synergies with decarbonization beyond the power sector can mitigate flexibility needs and reduce system costs.

Methods

The paper applies a bottom-up planning model that optimizes expansion and operation of technologies to satisfy final demand by minimizing total system costs. To capture the interplay of electricity supply and demand, it is not limited to the power sector, but equally captures operation and expansion of technologies in the heating, transport, and industry sector. Overall, the scope includes 22 distinct energy carriers that can be stored and converted into one another by 120 different technologies to satisfy final demand and transported by four different types of transmission infrastructure.

The model deploys a graph-based formulation specifically developed to model high shares of fluctuating renewables and sector integration, which is capable to vary temporal and spatial resolution within a model. Thanks to this feature, we can apply an hourly resolution in the power sector to accurately capture fluctuations of wind and solar, but model other energy carriers, like synthetic gases or hydrogen, at a coarser resolution to reduce computational complexity. In addition, the approach can capture the inherent flexibility, or elasticity, of electricity demand from other sectors. Space heating for instance, is modeled at a four-hour resolution to capture the thermal inertia of buildings.

Spatially the model covers the European continent subdivided into 96 regions. A large spatial scope and resolution are essential to capture how transmission infrastructure can smooth local variations of wind and solar generation and add flexibility to the system.

Results

For the analysis, flexibility needs can be distinguished on two specific timescales that drive the underlying patterns of solar generation, ambient temperature, and human behavior. The need for short-term flexibility is driven by daily; long-term flexibility by seasonal patterns.

On the short-term scale, results exhibit substantial benefits from flexible electrification. Demand from battery electric vehicles, heat-pumps and electrolyzers adopts to the profile of solar generation mitigating the need for short-term battery storage. These synergies are even more pronounced in scenarios with higher solar generation due to less wind potential or no expansion of power transmission. In these scenarios, often further flexibility is added by paring residential heat-pumps with thermal storage systems.

Long-term flexibility is driven by the seasonal mismatch of solar generation and residential heat demand. To prevent demand peaks from residential heat-pumps in winter, district heating technologies like more efficient heat-pumps, seasonal heat storage, combined heat-and-power plants, and backup boilers provide a major share of heat. Overall, the need for thermal backup plants is small, but increases substantially, if the wind potential is small and more solar generation occurs during the summer, or if transmission expansion is restricted.

Session 9:50 – 10:50
Low carbon energy transformation pathways I

Room: CHE/183
Chair: Hendrik Scharf

Developing low carbon scenarios for the European energy system: Exploring the role of renewable hydrogen in a sector-coupled European energy system towards 2050
Konstantin Löffler, TU Berlin

How does an early coal exit impact Germany's natural gas dependence? Implications of the current coalition contract for the power sector in 2030
Hendrik Scharf, TU Dresden

Is Germany on the right track to achieve 2030 climate and energy targets?
Smaranda Sgarciu, BTU Cottbus-Senftenberg

Developing low carbon scenarios for the European energy system: Exploring the role of renewable hydrogen in a sector-coupled European energy system towards 2050

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Keywords: energy system modeling, hydrogen, decarbonization pathways, energy policy, renewable energy sources

Motivation

The potential role of hydrogen in the transformation of the energy system currently receives increasing interest. In July 2020, the European Commission published a European hydrogen strategy, presenting a roadmap of actions for the coming years and identifying challenges to overcome in the process of deploying hydrogen at large scale (European Commission 2020). At the same time, many member states of the EU, among others Germany, France, and the Netherlands, developed more detailed national strategies.

These strategies identify the potential for hydrogen to play a prominent role in the decarbonization of the energy system. A main idea is to produce hydrogen from renewable energy sources, i.e., without emitting CO2, and to use it subsequently in consumption areas where electricity-based solutions are less suitable. Examples of these applications can be found across all sectors: In the power sector, hydrogen can serve as storage medium which is produced in times of high renewable power generation and used in hours of lower generation. In the transportation sector, hydrogen-fuelled fuel-cell electric vehicles may offer advantages compared to battery electric vehicles, especially for heavy duty transport (road-based, shipping and aviation). Moreover, various processes in the industry sector require very high temperature levels, which currently are achieved by burning fossil fuels, but could also be based on hydrogen. In addition, domestically produced, renewable hydrogen might be an important factor to energy independence - a rising political topic since the beginning of the Russian war in Ukraine.

The paper therefore looks at various aspects for low-carbon long-term pathways of the European energy system with a focus on hydrogen and its role in sector-coupling and decarbonization, across multiple modeled scenarios and sensitivities.

Methods

The open-source Global Energy System Model (GENeSYS-MOD) is applied to develop quantitative scenarios for the future European energy system. The objective function of GENeSYS-MOD covers the total cost of providing energy for the electricity, transport, heating, and several industrial sectors in a predefined region. The model result is a cost-minimal pathway for the energy system and capacity mix of technologies to fully meet energy demand towards 2050. Climate targets, such as a CO2 emissions budget, are explicitly specified as a condition for the model calculations. Further descriptions of GENeSYS-MOD and the functionalities are available in Löffler et al. (2017), Burandt et al. (2018), Burandt et al. (2019), and Hainsch et al. (2021). The model setup within the calculations for the openENTRANCE storylines covers Europe with a total of 30 nodes (EU25 + UK + CH + NO + Turkey + the Non-European Balkan countries grouped in one node).
The main focus points of this pape are the introduction of renewable hydrogen as a potential future energy source, along with the developments that this brings for the entire European energy system - also with regards to electricity requirements for electrolysis. Cross-sectoral effects are analyzed for several sensitivities, targeting key assumptions such as hydrogen transportation methods, import prices and availabilities, as well as availability of natural gas imports from Russia.
The model source code for GENeSYS-MOD can be found at its public GitLab page under https://git.tu-berlin.de/genesysmod/genesys-mod-public. All model files, including data, will be uploaded to this repository, allowing for fully reproducible and therefore transparent model results.

Results

Our preliminary results show that in all scenarios, electricity will primarily be provided by the provision of renewable energy sources. Hereby, onshore wind and solar PV power plants pose to be the major sources of electricity. The highest amount of electricity generated can be seen in the Gradual Development scenario due to the lack of strict demand-side reductions and efficiency increases compared to the other scenarios. In this scenario, the electricity production in 2050 is nearly twice as high as in the base year. The higher demand levels of the non-electricity sectors in Gradual Development also led to the highest amounts of domestically produced hydrogen in the system across all scenarios. In contrast, the three other scenarios see a peak of electricity generation in 2040 and a slight decrease afterward (compare Figure 1).
Some of the regional distributions in the model results can be seen in Figure 2, which shows some maps for comparison of various model outputs on a country level. This The upper row starts with three maps, displaying total hydrogen generation per country (left), electricity generation by wind (middle), and PV technologies (right). The bottom row shows the final

electricity consumption (excluding for electrolysis, as this is indirectly already shown in the hydrogen generation graph in the top left) on the left, hydrogen & synthetic methane exports in the middle, and hydrogen & synthetic methane imports on the right. The graphs clearly demonstrate that Spain and Turkey become the main suppliers of renewable hydrogen in Europe. This also shows in the total electricity generation from wind and solar, where these two countries excel, especially with regards to available potentials. As the graph shows, most final electricity (and energy) consumption is concentrated towards Central Europe, with Germany emerging as the main importer of hydrogen throughout Europe.

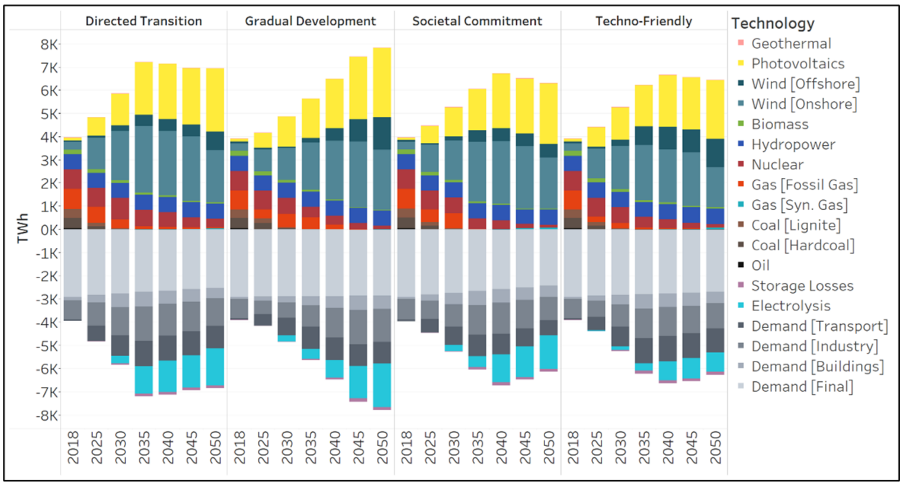

Figure 1

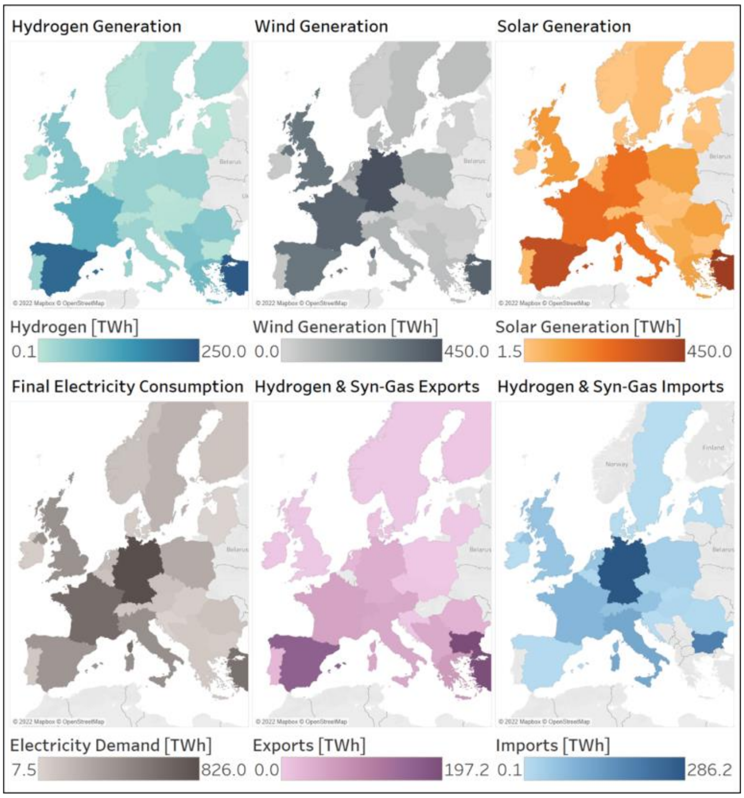

Figure 2

How does an early coal exit impact Germany's natural gas dependence? Implications of the current coalition contract for the power sector in 2030

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Keywords: power market, reliable capacity, natural gas, coal exit, expansion targets for renewable electricity

Motivation

Germany's current energy policy aims at phasing-out coal by 2030. Moreover, the coalition contract of the present federal government foresees a drastic increase in national power consumption by 2030. Besides, 80 % of the power consumption shall be covered by renewable energy. Gas power could fill the resulting niche while also providing reliable capacity. However, current geopolitical developments question the electricity sector's high dependency on natural gas as an energy source. Therefore, we analyze the implications of a German coal exit before 2030 on gas-fired power generation and capacities, wind and photovoltaics capacities, greenhouse gas emissions, as well as international power exchange.

Methods

We analyze the European power market of 2030 via a reference scenario and two variants of the reference scenario using the fundamental power market model ELTRAMOD-Invest. For the reference scenario, we assume 17 Gigawatt of coal-fired capacities to remain in the German power plant portfolio in 2030, following the 2038 phase-out plans of the German Act to Reduce and End Coal-Fired Power Generation. By contrast, both scenario variants assume a coal exit before 2030. The first variant sets Germany's gas-fired capacities to the levels of the reference scenario, showing how the earlier coal phase-out date could be tackled without installing even more additional gas-fired capacities. The second variant does not bind investments in gas-fired capacity in Germany. Both variants do not restrict the gas-fired capacity expansion in the other countries considered. The model includes an annual cap on system-wide greenhouse-gas emissions, Power-to-X technologies, sector-coupling, and the renewable electricity target share imposed in Germany.

Results

The results show that an earlier coal exit would increase Germany's dependency on natural gas and electricity imports. At the same time, phasing-out coal before 2030 significantly reduces German greenhouse gas emissions. While the analysis reveals almost no effect of a 2030 coal exit on German renewable capacities, it shows a considerable marginalization of renewable energy outside Germany. Contrary to the reference scenario, both scenario variations indicate a significant number of hours of stress during which Germany would be dependent on reliable capacity from abroad. Almost 100 % of the additional electricity generation required to close the power gap resulting from the early coal exit is sourced from natural gas. In the case of unrestricted gas-fired capacities in Germany, German natural gas-fired power plants fill almost half of the power gap induced by the early coal exit. Fixing gas-fired capacities in Germany shifts a large share of the additional power generation based on natural gas as fuel from Germany to other countries. However, even in the scenario variant with locked German gas-fired capacities, the German import dependency on natural gas increases clearly compared to the reference scenario. Further work could, e.g., analyze the impact of depleting greenhouse-gas emission certificates on the model results.

Is Germany on the right track to achieve 2030 climate and energy targets?

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Keywords: coal phase-out, CO2 price, climate and energy targets, decarbonisation pathway

Motivation

The impact of regulatory and market-based instruments for reducing carbon emissions in the electricity market has been thoroughly discussed in recent studies (Anke et al., 2020; Keles and Yilmaz, 2020; Osorio et al., 2020). However, the validity of the conclusions and policy recommendations in these studies hold only partially against the latest market developments. For instance, in the European Emission Trading System, the cost of CO2 emissions increased from 20–30 €/t of CO2 in 2019 to more than 80 €/t of CO2 throughout 2021. In 2022, the circumstances further changed once Russia invaded Ukraine: the energy carriers flows for natural gas, hard coal, and crude oil coming from Russia towards Western Europe have decreased. Prices for both fuel and electricity have skyrocketed and are more volatile. A short-term implication is that more coal will be burned in the power sector. In the long term, more renewables will enter the system.

Considering the complex interplay between CO2, coal and gas prices and the associated fuel scarcity, it is unclear how CO2 emissions in the German electricity sector will develop until 2030, thus a reassessment is needed.

Methods

We analysed the possibility that Germany reaches their 2030 climate targets based on a fundamental electricity market model – EM.POWER Invest. The Pan-European model dynamically determines investment and dispatch in partial equilibrium and assumes perfect foresight. To tackle the computational complexity that such models demand, we implement an innovative three-stage approach that preserves results tractability without losing key information.

The model was parameterized with the latest market developments in 2021, i.e., before the Russian attack on Ukraine.

EM.POWER Invest was parametrised with two scenarios to account for the potential development of carbon emissions in the German market from 2022 until 2030. One scenario called "regulated divestment 2019" imposes a negotiated coal phase-out. This restricts the operation of the coal-fired power plants to the latest decommissioning date, namely 2038. The other scenario entitled "increased CO2 price 2021" considers the restriction of coal power plants to the same decommissioning date, while imposing a high carbon price similar to the one registered in 2021.

Results

Our policy discussion highlights important matters regarding latest developments of the European electricity market and how they could influence the German trajectory towards a climate neutral electricity sector.

Our results show that a regulatory induced phase-out is not enough to reach 2030 climate and energy targets and that an increased CO2 price (as observed in the recent trends) would make climate and energy targets attainable. In view of the latest market developments, we focus our discussion onto the further aspects which could affect a successful decarbonisation pathway. Our discourse analysis and conclusions are relevant for policymakers with interest in strongly decarbonised energy markets.

Session 9:50 – 10:50
Advanced optimisation in energy economics

Room: CHE/184
Chair: Felix Schmidt

Hybrid Optimization - The impacts of extreme climate conditions on the future European electricity system
Maximilian Bernecker, BTU Cottbus-Senftenberg

Benders decomposition for energy system planning with multiple climatic years
Felix Schmidt, DIW Berlin

Multistage modelling approach to optimize investment and operational decisions in electricity markets with a high level of detail
Laura Torralba-Diaz, IER Stuttgart

Hybrid Optimization - The impacts of extreme climate conditions on the future European electricity system

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Keywords: uncertain climate conditions, energy system reliability, generation expansion planning, electricity market operation

Motivation

The transition towards a low-carbon energy system based on variable renewable energy (VRE) entails an extended dependency on weather conditions for energy production. Ensuring the reliability of the power system in the face of weather uncertainties exacerbated by climate change remains a major challenge. Although several studies analyze optimal capacity expansion plans either on a cost-minimization basis or considering potential carbon emission reductions, fewer studies take both objectives into account (Pohekar and Ramachandran, 2004; Zhou et al., 2015).

Methods

Therefore, we propose a multiobjective chance constrained optimization to analyse the optimal investment decisions of a Pan-European electricity system: this method is commonly used to analyze uncertainties in expansion problems or in electricity market analysis, e.g., in (Yu et al., 2009; Zhou et al., 2015; Dvorkin, 2020). Since the underlying model minimizes both total system costs and carbon emissions, we can analyze the tradeoff between these two objectives. We take into account both national energy transition perspectives and a European one. This enables us to identify and evaluate target-oriented and less target-oriented development paths of individual countries in an overall European context. From this, policy recommendations can be derived. Our contribution is three-fold: (1) we quantify the effect of parametric uncertainty of the variable renewable energy sources capacity factors and uncertain demand; (2) we quantify the expected energy not served and the value of loss of load; (3) we quantify the additional system cost of achieving carbon neutrality and the additional capacity needed to ensure security of supply.

Results

Overall, our results suggest that national climate targets are ineffective in achieving European climate goals in a cost-effective manner. Thus, the transition of electrical energy markets to climate neutral resilient systems shall be done on a European level and not a national one. Our illustrative modelling example and conclusions are relevant for both energy modellers and policymakers with interest in climatic effects on energy markets.

Benders decomposition for energy system planning with multiple climatic years

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Keywords: macro energy systems, stochastic optimization, decarbonization, Bender decomposition

Motivation

Key tools for analysing the transformation towards renewable electricity are techno-economic planning models. Formulated as linear optimization problems, models decide from a portfolio of technologies on their expansion and operation to satisfy an exogenous final demand at minimum costs and subject to boundary conditions, for instance emission limits. Typical applications include the development of long-term scenarios for the energy system, assessment of technologies in a system context, and analysis of energy policy. The fluctuating nature of PV and wind generation is a challenge for planning models. For conventional energy systems characterized by dispatchable generation from thermal power plants, a small number of representative time-periods is sufficient to achieve accurate results. Capturing fluctuations of PV and wind however requires a much higher temporal resolution, that greatly increases model size and easily renders the linear optimization problem computationally intractable (Göke and Kendziorski 2022). Addressing this issue, different techniques have been proposed to reduce computational complexity while representing renewables accurately, for instance iteratively adjusting the representative time-periods or limiting high resolution to selected parts of the system.

Methods

Benders decomposition (BD), first introduced in Benders (1962), is a decomposition technique to solve optimization problems capable to solve two-stage stochastic problems based on scenarios, like planning models with multiple climatic years, and potentially improve their computational tractability. In this case, the problem is decomposed into a master-problem (MP) addressing technology expansion, and several mutually independent sub-problems (SPs) for operation. Afterwards, the MP and SPs are solved repeatedly to generate constraints, so-called Benders cuts, that are added to the MP until the algorithm converges (Conejo et al. 2006). In several applications of BD with energy planning models, each SP corresponds to a short time-span of the

year, even just an hour (Lohmann and Rebennack 2017; Brandenberg and Stursberg 2021). However, such decomposition is not applicable when modelling high renewable shares and including seasonal storage, which creates dependencies across the entire year. So, in this case each SP instead covers operation for a specific climatic year or scenario. Considering the high temporal detail of operation, this results in a simple MP and several large SPs.
For many problems the original BD converges slowly and is not competitive to closed optimization using off-the-shelf solvers. However, an extensive branch of research proposes different enhancements to improve the original BD. Our implementation of BD includes a multi-cut reformulation, parallel computing, and a trust-region paired with a simple heuristic to obtain an initial solution. We introduce a highly relevant problem with a structure well-suited for BD to the operations research literature and investigate to what extent existing refinements can accelerate the algorithm. Our Benders implementation deploys a refined version of the trust-region method for continuous variables using the l2-norm and dynamically adjusting the region's size.

Results

The results show that our improved method outperforms the standard BD algorithm by an order of magnitude. While the solve time of an integrated approach usually increases with a higher number of scenarios, our method in some cases even accelerates due to more efficient Benders Cuts. However, this comes at the cost of more time spent in a pre-solve heuristic, meaning that our method is only beneficial if the problem size is large enough and sufficient CPU resources are available to utilize parallel computing.

Multistage modelling approach to optimize investment and operational decisions in electricity markets with a high level of detail

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Keywords: multistage optimization, electricity market model, capacity expansion, model complexity, temporal resolution

Motivation

The energy transition is one of the greatest challenges of the 21st century: It requires a profound transformation of the entire energy infrastructure. In this context, bottom-up capacity expansion models enable the identification of cost-optimal future energy system configurations. They constitute one of the most powerful mathematical tools to provide scientific support in designing cost-effective energy transition pathways. In such models, investment decisions are usually optimized simultaneously to power plant utilization. This is because investments are evaluated on the basis of their expected techno-economic deployability. This guarantees the required stability and technical feasibility of the target system. However, the increasing complexity of the energy system makes the underlying mathematical problem nearly intractable by drastically increasing the computational effort. To keep the model complexity manageable, a multistage optimization approach is formulated and applied to the cost minimizing electricity market model E2M2. The aim of this approach is the identification of target systems that are not only cost-efficient but also technically highly resolved. This work is part of the project ERAFlex II (03EI1033B).

Methods

To overcome computational limitations, the optimization of investment and operational decisions can be carried out hierarchically, i.e., the optimization is split into several stages or model runs. From each of these stages certain results are fixed and transferred exogenously to the following stages. The considered planning horizon decreases over the successive stages, as the level of temporal and technological detail increases. Therefore, long-term decisions are determined in the initial stages; short-term decisions are calculated in the final stages in more detail. The challenge is to identify the most suitable temporal and technological configuration at each stage. Therefore, it is first necessary to know how different simplifications on these two model dimensions affect the model performance. For this purpose, a novel indicator is defined: the complexity reduction efficiency coefficient (CREC). It measures to what extent model outcomes diverge compared to the degree of complexity reduction achieved. The latter is measured in terms of CPLEX ticks. Low positive CRECs imply major reductions in ticks with comparatively minor result deviations. High positive CRECs are assigned to less effective complexity reduction techniques. Negative CRECs, on the contrary, involve an increase in ticks. The analyzed model simplifications are: 1) reduction of the level of detail of thermal power plants (TPPs) by simplifying a MILP formulation with detailed operational constraints into a LP approach (LPC) and by neglecting start-up and load change processes (LPS), 2) grouping of TPPs with similar characteristics based on their commissioning year in 5 (Vin5) and 15 (Vin15) year steps and according to their primary energy and engine type (Agg), 3) consideration of load-shifting demand response (DR) technologies as fictitious storage units (DRS) in addition to modelling them as compensation variables with two time-related indices (DRC), and 4) reduction of time steps.

Results

The analysis of the CRECs of the different representations of TPPs shows that it is not possible to consider MILP simultaneously to long-term investment decisions. This approach is computationally very intensive. To further decrease the computational effort when optimizing capacity expansion, neglecting start-up and load change processes (LPS) should be avoided. These can help to decrease the problem tightness and thus the number of ticks, see Fig. 1 (a,b). Fig. 1 (a) displays investment deviations and Fig. 1 (b) their CRECs with respect to the relative number of CPLEX ticks for several model runs with different combinations of temporal and technological simplifications related to TPPs. The reference model is formulated as a LP problem with start-up and load change constraints (LPC) as well as aggregated TPPs in 5 year steps (Vin5) and hourly resolution (8760). In addition, the combination of low aggregation levels in both model dimensions shows lower CRECs compared to larger aggregations in only one dimension. Fig. 1 (c) presents investment deviations and Fig. 1 (d) their CRECs with respect to the relative number of CPLEX ticks for different simplifications related to load-shifting DR technologies. In the reference model run, these units are formulated as compensation variables with two time-related indices (DRC). However, the model performance is found to be more robust to reductions in the temporal resolution if they are considered as fictitious storage units (DRS). The effect of decreasing temporal resolution is thus highly dependent on the underlying technological assumptions. Based on the comprehensive analysis, a suitable configuration of the multistage approach is established. This allows to model investment and operational decisions at a high level of detail with manageable computational effort and without compromising the accuracy of the results. Future research involves comparing this approach with established methods, such as a myopic foresight.

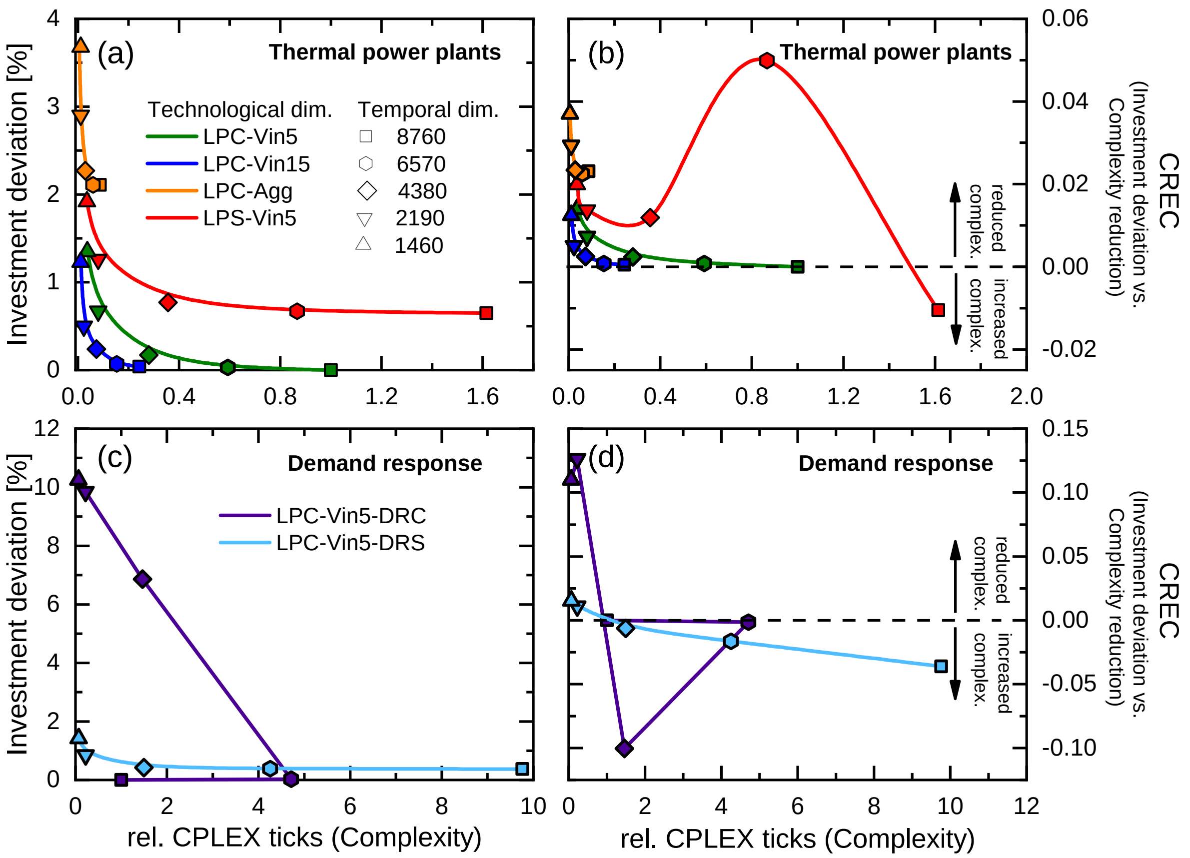

Figure 1: (a,c) Investment deviations from the reference model run and (b,d) coefficient between investment deviations and model complexity reduction (CREC) with respect to the relative number of CPLEX ticks (complexity relative to the reference model run), respectively. Several model runs with different combinations of temporal and technological simplifications are shown: (a,b) for TPPs and (c,d) for load-shifting DR technologies. LP approaches with (LPC) and without (LPS) start-up and load change processes are considered. Aggregation of TPPs is based on their commissioning year in 5 (Vin5) as well as 15 (Vin15) year steps and according to their primary energy and engine type (Agg). Load-shifting DR technologies are simplified as fictitious storage units (DRS) in addition to modelling them as compensation variables with two time-related indices (DRC). Temporal simplification is a reduction of time steps. The reference model run is LPC-Vin5-8760 for (a,b) and LPC-Vin5-DRC-8760 for (c,d).

Session 11:15 – 12:15
Hydrogen markets and market integration

Room: CHE/S91, hybrid
Chair: Lauritz Bühler

The role of hydrogen in a sector-integrative European energy system model

Christoph Schmitz, r2b energy consulting GmbH, **[cancelled]**

Green hydrogen - How grey can it be?

Johannes Brauer, MINES ParisTech

Global hydrogen trade - A single-period mixed complementary model for the global hydrogen market in 2030

Leonhard Dux, TU Berlin

The role of hydrogen in a sector-integrative European energy system model

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Keywords: hydrogen, energy market model, sector coupling, energy supply, energy and climate

Motivation

Hydrogen electrolysers for the production of hydrogen will play an important role in energy systems in the future. In addition to serving as a substitute for fossil fuels to decarbonise the economic sectors of industry, heat and transport, and as an energy storage system in the gas and electricity sectors, a key task of electrolysers can be to relieve the burden on elec-tricity grids. For these reasons, the current coalition government in Germany is planning to install 10 GWel of electrolysers by 2030. In Europe, the European Hydrogen Strategy aims for 40 GWel of electrolysis capacity producing 333 TWhth of green hydrogen by 2030 - a figure that is only likely to be revised upwards since its publication in 2020.

In the wake of these announcements, important regulations are taking shape. Especially no-table are quotas for green hydrogen in industry applications and the transport sector, and the definition of what green hydrogen actually constitutes. These regulations interact with as-pects of sector coupling, the regional availability of (additional) RE generation potentials in Europe, and technological development. To reliably answer any questions about the upcom-ing hydrogen economy, a comprehensive, sector-integrative European energy system model is indispensable, in which all these aspects are considered simultaneously.

This work aims to show which mechanisms such an energy system model should depict, which regulatory aspects need to be considered, which economic and technical parameters are required. Further it is shown which interactions arise between the aspects mentioned and how they affect expected results, especially concerning the regional allocation and utili-zation rates of electrolysers in the European energy system as well as the expansion of re-newable energy sources required to produce green hydrogen.

Methods

We model the European energy system from 2021 up to 2060, at it's core the electricity system. Adjacent systems, such as public heating and parts of transport and industry are also incorporated. Based on the status quo of European energy systems in terms of generating assets, total costs are minimized via investments in technologies and their hourly dispatch

throughout the year (thus representing efficient markets). The approach is based on exten-sive weather data, as well as relevant national and supranational policies and regulation.
The demand for the commodity hydrogen can be split into demand for energy, and demand for molecules. While the first is mostly defined by opportunity costs – e.g., is it more cost-efficient to power a generator with natural gas or with hydrogen – the latter is exogenous from the perspective of the energy system and stems from chemical processes. Of both, a certain percentage is required to be “green”, according to regulation and intrinsically moti-vated decarbonisation efforts of actors.
In serving these demands, electrochemical hydrogen competes with “blue” and “grey” hy-drogen from steam reforming. Regulatory definitions of “green” hydrogens are accurately modelled, contrasting it to “yellow” hydrogen (electrochemical, but not green). Endogenous investment in both electrolyser technologies (low- and high temperature), as well as in addi-tional renewables ensures that the resulting capacities are economically cost efficient.

Results

Our analyses show: Despite completely different conditions, electrolysers are being built economically throughout Europe. Germany and France are the frontrunners with the highest installed electrolyser capacities. The mode of operation depends centrally on the site condi-tions in the European country comparison. Full-load hours vary significantly, between ap-prox. 3,200 for low-temperature electrolysers in southern Italy and approx. 7,800 full-load hours (basically baseload) for high-temperature electrolysers in Scandinavia. Appropriately designed hydrogen regulation can stimulate a considerable, economically motivated expan-sion of the associated “additional” renewables. Producing green hydrogen with grid electric-ity, i.e., not constraining the electrolyser dispatch to the infeed of coupled additional renew-ables (PPA and/or directly linked) only starts to gain relevance once national emission in-tensities of electricity go down. This is the case early on in countries such as Norway and Austria, but quite late in Germany. In the long term, imports of green hydrogen will also play an important role. Crucial drivers for the regional allocation of hydrogen production within Europe are, among others, regional/national demand for (electrochemical) hydrogen, region-al renewable energy potentials, as well as the development of transnational hydrogen transport capacities, which is not expected to meet the pace of the increases of national demand and production capacities.

Green hydrogen - How grey can it be?

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Keywords: electrolytic hydrogen, regulation, electricity market, welfare

Motivation

Electrolytic hydrogen is expected to play a key role in the European energy transition. However, depending on the origin of the electricity, hydrogen production is associated with different carbon emissions and costs. While a strict coupling of renewable energies to electrolysers ensures the 'greenness' of the product, it likely leads to higher production costs. On the contrary, procuring electricity freely at power markets unleashes the flexibility of electrolysers, allowing them to benefit from price signals and possibly reducing production costs. However, the carbon intensity in both the power system and the resulting hydrogen product might rise. Consequently, there is a trade-off between environmental integrity and economic viability which affects social welfare and the decarbonisation process. Therefore, the recognition of electrolytic hydrogen as a homogeneous good does not seem appropriate, which requires the introduction of clear definitions and regulations. Policymakers are about to frame those conditions. As the successful development of a low-carbon hydrogen economy is important to not only meet the overarching decarbonisation goal in a timely and socially acceptable manner but also to ensure competitiveness of the EU industry and to maintain a technology leadership in the sector, research on this topic is needed. Our work aims to shed light on which regulation is beneficial in terms of the trade-off between environmental integrity and economic viability in the production of electrolytic hydrogen. We assess the impact of various regulatory options for the operation of electrolyser systems on social welfare and carbon emissions. These options are based on the three dimensions proposed in the ongoing regulatory discussions: (1) the origin of the sourced electricity, (2) the temporal correlation of the production of hydrogen and renewable electricity and (3) their spatial correlation.

Methods

A quantitative approach is chosen. The core of the analysis is to assess the interaction between the production of electrolytic hydrogen and the operation of the power system. Therefore, an electricity market model (perfectly competitive) is developed. The analysis consists of three consecutive steps: In the first step the electricity market model is applied in a capacity expansion mode, meaning that for the considered geographical scope the model can decide endogenously about the commissioning of new or the decommissioning of existing generation units. In the second step of the analysis the electricity market model is applied again. However, this time, the focus is on the operation of the generation units and the changes to the power system caused by the introduction of hydrogen demand. The optimised generation fleet from the first step is used as input and an exogenous daily hydrogen demand is introduced, that needs to be supplied in a captive manner. In this second step, the model can invest in all system components (batteries, electrolyser, hydrogen storage, additional renewables depending on the analysed regulation) that are required to supply the hydrogen demand in a least-cost manner and to size their respective capacities. In the third and last step of the analysis, the outcomes of all modelled regulations are compared based on various parameters. The effect of the regulations on the hydrogen production cost, the CO2 emissions and the overall welfare are of particular interest. The model is applied to the case of Germany in 2030 which represents the ramp-up phase of a low-carbon hydrogen economy in the country. Although there are many possible regulatory options, only a selection (based on trials during the research work) of them is analysed and discussed in this study. The options range from off-grid systems supplied entirely by renewable energies to fully grid connected hydrogen production systems without requirements on the sourced electricity.

Results

We find that strict requirements generally benefit environmental aspects, while loose conditions favour hydrogen production costs and total welfare (not accounting for the environmental costs). However, too strict regulatory designs on the geographical dimension that only allow for the sourcing of renewable electricity generated in proximity do neither result in beneficial economic nor in optimal environmental outcomes. While in the most environmentally friendly regulation 4.7 Mt of carbon emissions can be reduced, the best economic outcome results in 0.9 Billion EUR of welfare gains. The main driver for increasing welfare is identified to be reductions in hydrogen supply costs that vary by about 15% among the analysed regulatory designs. Moreover, the results show that stricter requirements result in substantial surplus renewable electricity that does not only replace some fossil generation to reduce carbon emissions but that also decreases electricity market prices and hence, favours consumers. We conclude that when designing regulation, policymakers must strike a careful balance between environmental and economic aspects to neither harm the decarbonisation process nor the ramp-up of a low-carbon hydrogen economy. Favouring one over the other might result in undesirable effects. However, weighting the various advantages of relatively strict regulations on all regulatory dimensions against the comparatively minor economic disadvantages, suggests that stricter regulatory designs are well-suited to reduce carbon emissions, exonerate consumers financially, further upscale renewable energies to achieve additional learning effects and to reduce natural gas demand helping to diminishing import dependencies (REPowerEU). Moreover, we find that with a progressing energy transition, the need for such regulation diminishes, as electricity from renewable energies represents both the best economic and the best environmental option, so that the observed trade-off disappears.

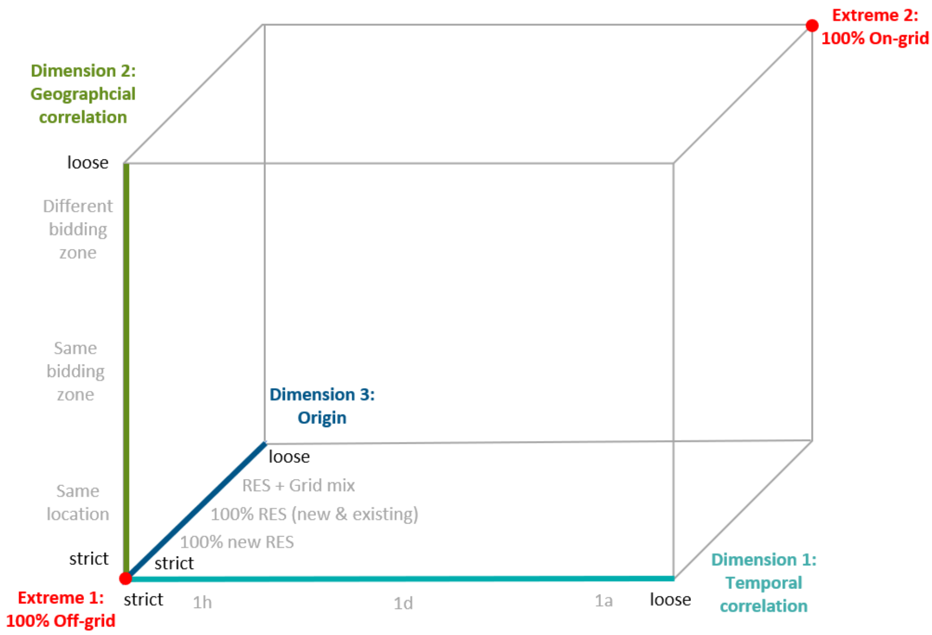

Figure 1

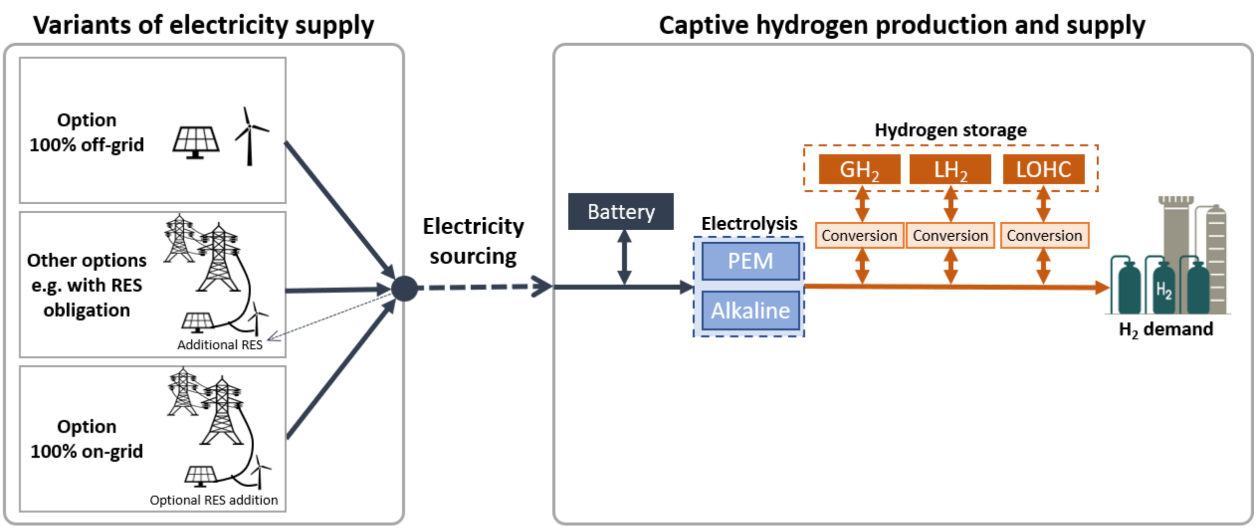

Figure 2

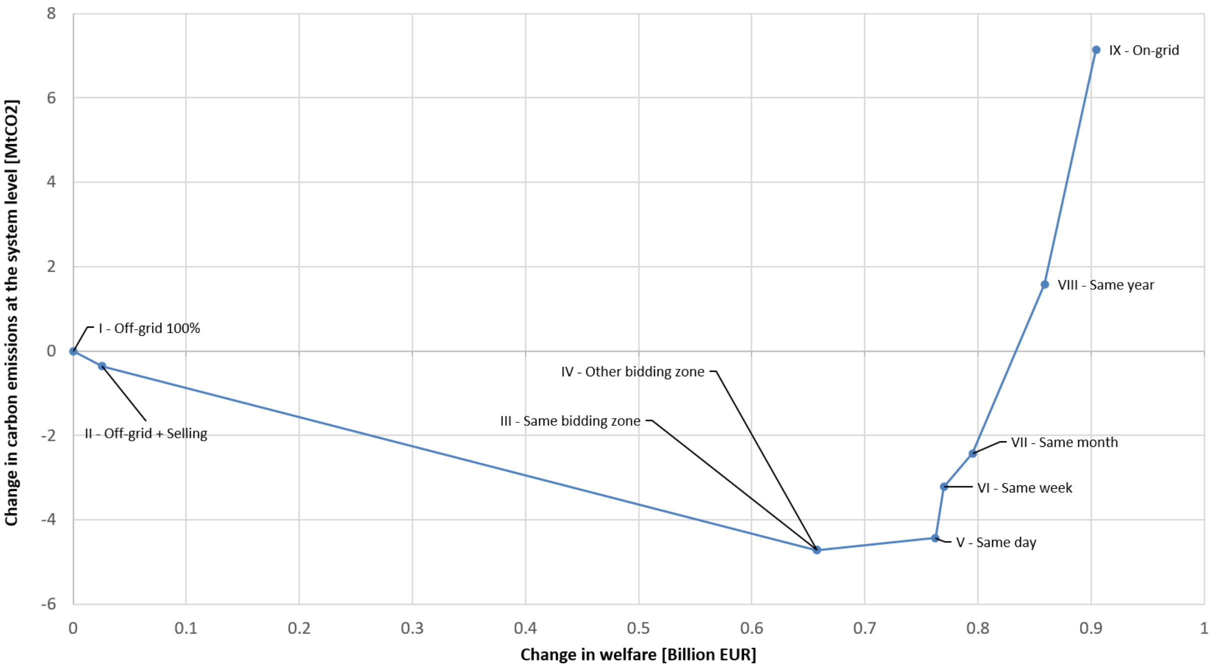
Change in carbon emissions at the system level [MtCO2]
Change in welfare [Billion EUR]
I - Off-grid 100%
II - Off-grid + Selling
III - Same bidding zone
IV - Other bidding zone
V - Same day
VI - Same week
VII - Same month
VIII - Same year
IX - On-grid

Figure 3

Global hydrogen trade - A single-period mixed complementary model for the global hydrogen market in 2030

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Keywords: liquified hydrogen, hydrogen trade, hydrogen shipping, mcp

Motivation

Renewable energy is central to an emission-free society. Potentially, hydrogen and other products based thereon may play a crucial role in future renewable energy systems for means of energy storage and transportation. In combination with strong spatial variance of renewable generation potentials, global hydrogen markets may become a reality. With recent ambitions of traditional energy exporting regions as well as those of new incumbents, investigating the influence of market power may be of central interest.

Methods

We present a static, single-period mixed complementary model for the global hydrogen market in 2030. For reasons of explainability, our simplified model only relies on trade via liquefied hydrogen with a focus on the effects of market power on traded quantities and prices. The model is based on an earlier formulation of the „World Gas Model" developed by Egging, Holz and Gabriel (2010). In an illustrative case, six continents are covered by the model's data set, including Asia, Europe, North and South America, Africa and Oceania. Each node represents a market with different players such as producers, liquifiers, and regasifiers selling to wholesale markets.

Results

Our results show that there is a trend towards regional supply structures if market power is assumed not to play a role. As prices rise in cases of market power exertion, shipping hydrogen becomes increasingly lucrative. Counterintuitively, there exist regions where prices drop in cases of market power exertion. Here, Asia may serve as an illustrative example. In perfect competition, cheap neighboring producers are willing to supply domestic markets up to their capacity limits. However, when they start to actively withhold supply in these markets, excess quantities are supplied mainly to Asia, resulting in prices decreasing from a previously elevated level.

Session 11:15 – 12:15
Sector coupling and market innovation

Room: CHE/S89, hybrid
Chair: Hannes Hobbie

Suggestions for improvements in TSOs regulation to foster energy innovation

Eva Marie Kurscheid, TenneT TSO GmbH

Investments in coupled energy sectors and market pricing

Jonas Egerer, FAU Erlangen-Nürnberg

Power sector effects of different supply chains for green hydrogen in Germany

Dana Kirchem, DIW Berlin

Suggestions for improvements in TSOs regulation to foster energy innovation

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Keywords: innovation, energy transition, revenue regulation, subsidies, technnology neutrality

Motivation

Europe's energy system is changing driven by increased adoption of low carbon technologies, more automation and digitalisation, further decentralisation and the consumers developing into demand-side active participants. The electricity grid operators play a key role in speeding up the deployment of clean energy. The transition to a low carbon future especially covers the penetration of volatile renewables e.g., wind and solar, new technologies such as utility-scale batteries and hydrogen in combination with fossil fuel powered generators disconnecting from the system. Customers developing into active players in the system requires the electrification of end-users in industry, heat and mobility, the development of demand response programs for distributed energy storage and smart devices, furthermore new demand patterns with the emergence of flexibility providers. More automated operation of the system implies new network technologies such as smart metering, remote control and automation beyond the meter trends such as optimisation and aggregation platforms and the development of forecasting capabilities using artificial intelligence. Dealing with decentralisation requires connecting a range of new technologies and new actors, dealing with changes in supply and demand patterns up to the change of consumers into prosumers and electricity being produced closer to where it is consumed. TSOs are committed to fulfil their assignment at the best of their ability. Regulatory improvements can support TSOs in performing the energy transition.

Methods

Social-economic analysis: The essential issue is under-investment in innovation. From a socio-economic point of view and irrespective of the market structure, the level of investment in research and development is supposed to be low. The reasons are as follows:

- Limited appropriability: the inability of the firm to retain all of the added value it creates for its own benefit i.e. in case of positive externalities.
- Financial market failure: imperfections in capital markets lead to inaccurate allocation of resources due to both un-availability of information and un-ability to interpret information.

To overcome underinvestment in innovation, incentive structures can be designed as an ex-ante fixed R&D budget or as innovation/R&D subsidy for TSOs on a project basis. Having an ex-ante fixed R&D budget insures a TSO against any financial downside risks of innovation. Determining an appropriate and purposeful R&D budget ex-ante is very difficult due to information asymmetry. In contrast to this, innovation/R&D subsidies are able to precisely tackle the gap between social and private business case of an innovation exercise. For projects in the early stages - R&D and piloting - innovation subsides are suitable because they allow the regulator to cover innovation related risks whilst enabling efficient spending.
Under the current German regulatory framework, subsidies are treated as non-interest-bearing debt, resulting in a lower return on equity. This should also be addressed in Germany to make sure that innovation subsidies work effectively.

Results

Since a structural increase in operating costs (OPEX) is to be expected, the current revenue regulation based on historical costs leads to an under-compensation of efficient operating costs and to associated misaligned incentives. Furthermore, the current revenue cap could lead to the substitution of operational solutions with capital intensive expenditures (CAPEX). This may lead to limited technology neutrality and rather create incentives to invest in capital-intensive rather than socially beneficial projects. To overcome both mentioned shortcomings, the introduction of forward-looking estimates is recommended. It is important to note that TenneT has committed by law and additionally under a corporate social responsibility policy to invest in welfare-enhancing and climate-neutral assets. Due to the current revenue regime, there is a risk that TSOs underinvest in innovative activities, i.e. activities that reduce future expenses or increase future output. Compensating for high-risk innovation through dedicated subsidies may help to bridge the gap between investments that are attractive to the private sector and those that are beneficial to society.

Investments in coupled energy sectors and market pricing

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Keywords: sector coupling, market design, investment

Motivation

The low-carbon transition of the energy sector is central for reaching climate neutrality of the European economy. With increasing levels of renewable electricity generation, the concept of sector coupling is gaining increasing attention in energy-economic research and policy discussions. With the complete decarbonization of the power sector, renewable electricity will substitute fossil energy carriers in heating and mobility, either directly or as input for the production of sustainable fuels like green hydrogen. These energy carriers are promoted to decarbonize some emission-intensive industries, backup power generation, and possibly certain types of mobility and which cannot be easily electrified. The production of green hydrogen via electrolysis with renewable electricity is the only sustainable long-term solution for hydrogen-based energy carriers, which will result in coupled markets for electricity and hydrogen, i.e. by electrolysis and power generation.

Methods

To gain a better understanding of the impacts of market pricing for coupled energy sectors we develop a multi-level sector-coupling market model, considering different market designs, i.e., different bidding zone configurations, e.g., one or two bidding zones per energy carrier, and different time characteristics, e.g., hourly or daily trading, for the energy products. The mathematical setup represents a three-level model, starting with the investment in transport infrastructure at the first level by the regulated transmission system operators to maximize overall cross-sector social welfare. At the second level, private firms in both markets choose investment in conversion, generation and storage capacities anticipating their revenues from subsequent spot-market operations within their bidding zones. At the third level, the transmission system operators choose congestion management measures to minimize overall cross-sector costs for the implementation of the market outcomes under the constraint of the final demand results of the spot market and the transmission capacity limits of the first level. In order to render the model feasible, investment in backup capacity is possible to meet the final demand at each network node. We distinguish in sector-specific generation and sector-coupling technologies that differ in the fact that the input factor for sector-coupling technologies is endogenously given within the modeling of the coupled sectors, while the input factor for sector-specific generation technologies is exogenously given by fixed input prices, as the sectors inheriting these energy carriers are not included in the modeling. In addition, storage assets are included to increase flexibility options within the optimization.

Results

The sector-coupling model is applied in a case study to discuss the design of future coupled hydrogen and electricity markets using two bidding zones per energy carrier for our analysis. We consider all possible combinations of the bidding zone configurations and combine these configurations in a green field approach with only new investments in generation, sector-coupling, and storage assets. The temporal setting follows the standard energy market design of electricity and fossil gas markets. As it is the case in Germany, electricity is traded on the spot-market mostly on an hourly basis, so the traded product in the electricity sector is a one-hour-product. As a German and especially global hydrogen market is currently developing, the duration of the trading period and thus the standard product traded on the future hydrogen spot market is not generally fixed yet. Therefore, different possibilities for the hydrogen market are considered in this paper, e.g., twenty-four-hour product or one-hour-product. In the hourly resolution of the hydrogen data, we use a daily variation with peak and off-peak times to reproduce future hydrogen-consuming industry behavior as accurately as possible. As an extension, two different scenarios for hydrogen supply options are considered, one with completely self-supply within the two bidding zones by electrolysis assets, one with possible hydrogen import with an exogenous import price in one or both hydrogen bidding zones.

Power sector effects of different supply chains for green hydrogen in Germany

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Keywords: green hydrogen, sector coupling, power sector analysis, flexibility, power system optimisation

Motivation

The production of hydrogen based on renewable energy sources (green hydrogen), is regarded as an integral part of the decarbonization strategy for sectors which are difficult to electrify, such as certain industries or freight transport. The main process to provide green hydrogen is electrolysis, which requires water and electricity. In order to meet demand for green hydrogen in the future, the number of electrolyzers needs to increase substantially in the upcoming years. In Germany for example, the government coalition has set a capacity target for electrolyzers of 10 GW by the year 2030.

In the course of this, the temporal flexibility characteristics of the additional electricity demand for electrolysis will determine whether green hydrogen can make a beneficial contribution to the integration of variable renewable energy sources, or conversely impose additional challenges for the power system. If hydrogen supply is sufficiently flexible, e.g. with low-cost storage options, electrolysis can make use of renewable energy surpluses.

This study investigates how different green hydrogen supply chains impact power system costs, capacity investments and dispatch. While many studies have explored the techno-economic aspects of green hydrogen, little regard has been paid to the power system effects so far. Existing studies focus on the costs and potentials of green hydrogen, but often base their analysis on exogenous assumptions for electricity production. Other studies rely on exogenous assumptions of electricity prices for the examination of different production and distribution chains for green hydrogen. In contrast, we explicitly consider the interactions between the electricity system and the hydrogen supply chain with a special focus on temporal flexibility in this study. We determine the optimal power plant and electricity storage portfolio and operation, as well as electrolyzer capacity, depending on different on-site or off-site storage options for hydrogen.

Methods

We use the open-source power sector model DIETER (Dispatch and Investment Evaluation Tool with Endogenous Renewables), which is a linear program that determines least-cost capacity and dispatch decisions for a full year in an hourly resolution. DIETER can capture various aspects of sector coupling between electricity, heating, transport and power-to-X. The model includes a detailed representation of the hydrogen sector, elements thereof are used in this study. We use DIETER to model the German power sector in 2030 as well as its interconnection to the stylized power sectors in neighboring countries. We also model Germany as an energy island in a different set of scenarios to separate effects related to geographical balancing. In order to reduce computational complexity and increase tractability, we only allow for endogenous capacity expansion in Germany. We further limit hydrogen production and demand to Germany, abstracting from the development of the hydrogen sectors in other countries. Hydrogen demand is given exogenously as a flat hourly demand profile. In general, we assume a renewable energy target of 80 percent of total demand, while the additional electricity demand of the hydrogen sector needs to be covered by 100 percent renewable energy in a yearly balance. Capacity expansion of wind energy in Germany is constrained by targets formulated by the current German government. In another setting, we provide a more green-fielded approach by not limiting the wind energy capacity expansion. Finally, we distinguish between three different hydrogen supply chains, which are exclusively represented in each scenario: On-site storage of hydrogen in high-pressure tanks, on-site storage in caverns and off-site cavern storage. We do not consider hydrogen liquefaction or liquid organic hydrogen carriers. In the hydrogen sector, capacity investments and hourly operations of the two electrolysis processes as well as H2 storage investments are endogenous model decisions.

Results

Our results show that the provision of green hydrogen requires substantial additional investments in variable renewable generation capacity (see figure 1). In order to meet the assumed demand for green hydrogen, between 28 GW and 53 GW of additional renewable energy capacity is required when wind energy capacity expansion is constrained. In that case, the additional renewable energy capacity stems solely from solar PV. This value varies significantly when wind energy capacity can be further extended, in which case only between maximum 16 GW (Germany integrated) and 21 GW (Germany isolated) of additional renewable energy capacity are required due to the demand for green hydrogen. This is also reflected in the capacity dispatch (see figure 2), underlining that the additional electricity demand for green hydrogen can be met by solar PV with limited potential for wind capacity expansion, given that sufficient PV capacity is installed. Regarding different hydrogen supply chains, low-cost cavern storage provides sufficient temporal flexibility to reduce the additional capacity needs, with on-site cavern storage requiring less additional generation capacity than off-site cavern storage. Additional power system costs induced by green hydrogen are also the lowest in the scenarios with cavern storage (see figure 3), particularly with high renewable energy shares where seasonal storage is particularly valuable. The transport costs connected to off-site cavern storage offset these cost reductions partly. The benefits from flexibility in the hydrogen sector highly depend on the availability of other flexibility measures. For example, in the scenarios in which balancing via interconnection between countries is facilitated, the system benefits of the flexibility in the green hydrogen supply chain are less pronounced. Based on these findings, German policy makers should continue and increase their efforts to promote flexibility in the electricity and hydrogen sector.

Session 11:15 – 12:15
Low carbon energy transformation pathways II

Room: CHE/183
Chair: Lucas de la Fuente

Policy effects and implications on the future low-carbon energy and transportation sector

Karlo Hainsch, TU Berlin

Premature nuclear retirements and nuclear decommissioning funds: Insights from New York

Muhammad Maladoh Bah, University of Basel

Nuclear bias in energy scenarios – A review and results from an in-depth analysis of long-term decarbonisation scenarios

Björn Steigerwald, TU Berlin

Policy effects and implications on the future low-carbon energy and transportation sector

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Keywords: decarbonization, energy policy, energy system modeling, GENeSYS-MOD, transportation

Motivation

The transportation sector is of particular interest for the low-carbon transformation of the energy sector, since it is the only sector in Europe and Germany with emissions still being higher or around 1990 levels. Currently relying heavily on fossil fuels (i.e. oil), the future transportation system will likely see more electrified options if decarbonization is to be achieved. This, however, puts an additional stress on the energy system, as the electricity required to power vehicles and trains needs to be produced through renewable energy sources and is also required for the decarbonization of other sectors like industry or buildings. Therefore, energy system models can help with analyzing the interactions between all energy sectors and propose solutions on how the long term transformation should be approached.

One apparent issue when analyzing future systems, no matter the domain, is the uncertainty that comes with it. Predicting the future is impossible yet trying to is necessary to gain insights into interactions and dependencies. The energy system will undergo a significant transformation in the upcoming years to achieve the targeted climate goals and future (uncertain) developments will have a strong influence on the shape of the transformation. Today, policy and decision makers need to put the regulatory framework in place which will facilitate this transformation, relying on analyses and predictions on the effectiveness of their methods.

Consequently, when analyzing possible futures and developments of the energy and transportation sector it is imperative to understand how the system is affected by different parameters which today are still uncertain. This work aims to answer the question of what are the impacts of key (uncertain) energy and transportation system parameters on the success of the German energy and mobility transition and which areas policy makers should target to generate the biggest impact.

Methods

GENeSYS-MOD is an open-source energy system model which is tailored towards long-term energy system transition pathways and based on OSeMOSYS. Since its first publication in 2017, it has been applied in numerous case-studies and projects. With the different energy sectors becoming increasingly connected in the future energy systems, due to sector coupling and electrification, GENeSYS-MOD analyses these sector interactions by simultaneously optimizing investments, energy generation, and dispatch while considering regional particularities and possible climate policies.

Several methodologies exist to address uncertainty in modeling. The most common ones either focus on directly addressing it through stochastic modeling, applying limited foresight to the model, or altering uncertain input parameters in the form of scenarios or a sensitivity analysis. More specifically, sensitivity analysis describes the approach of changing single input parameters and observing the models behaviour, being able to directly attribute changes in the results to the parameter of interest. In this study, the methodology of exploratory sensitivity analysis will be used to quantify the effects of four different factors on the overall energy system and the transportation sector in particular.

The four factors which will be analyzed are the following: carbon price, transportation demand, hydrogen generation efficiency and costs, and modal shift. For this study, a base-case is modeled and used as a reference, taking into account current projections, phase-out targets, price and demand developments, etc. In a second step, parameters which can be attributed to one of the four aforementioned factors are slightly altered one by one to analyze their impact on the future energy and transportation system. 100 sensitivities are computed for each case, leading to a total of 400 deviations from the base case.

Results

The results of the base case describe a pathway which heavily decarbonizes the German energy sector but still fails to achieve most of the governments set climate targets (e.g. the 1.5 °C climate target, 15 million electric vehicles in 2030, climate neutrality by 2045). Electricity generation needs to be decarbonized quickly to facilitate the electrification of the other energy sectors and, at the same time, expanded significantly in terms of renewable energies to be able to provide the increased demand. Similarly, the transportation sector is quickly transformed towards electricity based technologies or biofuels where direct electrification is not an option.

The sensitivity analysis highlights that transportation demand has the overall largest effect on most of the considered KPIs, directly affecting primary energy demand, emissions, and vehicle stock to a large degree. A more pronounced modal shift also has a strong effect on number of vehicles, especially when considering that the chosen range of the sensitivity is much lower than of demand. With the electricity sector most likely leading the way in terms of decarbonization, shifting transportation demand from cars to trains can lead to a reduction of emissions even before the large-scale deployment of electric vehicles. The increased electricity demand would be comparably low.

With respect to carbon prices, the results show relevant results across almost all KPIs. The strongest effects which can be observed on hydrogen production and electricity generation are partially influenced by the effects of a carbon price on the other sectors. Lastly, the Hydrogen case has the least impact across all KPIs with only hydrogen production being affected notably. In general, policy makers should target areas of directly reducing transportation demand or shifting it from less efficient modes (cars, trucks) to rail or public transport.

Premature nuclear retirements and nuclear decommissioning funds: Insights from New York

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Keywords: nuclear power plant, nuclear decommissioning, ZEC, New York, electricity market

Motivation

In the past decade, the outlook of nuclear power plants operating in wholesale U.S. electricity markets deteriorated substantially, leading to a modest wave of early nuclear retirements. Between 2018 and 2020 alone, six reactors with a combined capacity of 4.7 GW shutdown prematurely due to adverse economic conditions. To reverse the trend of premature nuclear retirements, five U.S. states introduced short-term targeted subsidies for vulnerable nuclear power plants collectively known as 'Zero-Emission Credits (ZEC)'. Various reasons were put forth to justify the subsidy legislations, including meeting state energy targets and preserving the zero carbon attributes of nuclear plants. However, the subsidies are short-term measures that are all set to expire by 2030, thereby raising the possibility of imminent nuclear shutdowns in the coming years.

Premature nuclear power plant retirements severely curtails income streams which has direct implications on the adequacy of funds for safely decommissioning the facility. In the context of the U.S, majority of nuclear licensees are mandated to accumulate decommissioning funds over the lifetime of a plant. The funds are segregated in a decommissioning trust fund (DTF) for the sole purpose of decommissioning the facility at the end of its lifetime. Since much of the funds are accumulated over the later phase of the plant's lifespan, early retirement poses a potential risk on the adequacy of decommissioning funds.

In light of the aforementioned issues, two crucial policy-relevant questions emerge which is the focus of this paper: first, what are the total costs of phasing-out nuclear plants in the State of New York in comparison to the costs of the nuclear subsidy program? Secondly, in the event of an early nuclear plant phase-out, what are the potential implications on the income streams of nuclear power plants and by extension the sufficiency of decommissioning funds?

Methods

The core of the research framework is a detailed bottoms-up economic dispatch model of the New York Independent System Operator (NYISO) zonal system. The model is calibrated to 2018, corresponding to a full year when upstate nuclear power plants in New York (Ginna, Nine-Mile and Fitzpatrick) were recipients of the ZEC's. The model is unique in the sense that it represents the NYISO system at a relatively high spatial resolution by incorporating the eleven internal NYISO zones. In the second step, results from the market model are entwined with a simplified computational method to address the adequacy of decommissioning funds.

Results

Results generated from the modeling framework would shed light on the total costs of phasing out nuclear power plants prematurely vis-à-vis the current subsidy legislation as well as proposed policy mechanisms. Additionally, results would highlight the potential implications arising from curtailed nuclear power plant revenues.

Nuclear bias in energy scenarios – A review and results from an in-depth analysis of long-term decarbonisation scenarios

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Keywords: energy, nuclear, AR6 scenarios, IAMC 1.5°C scenarios

Motivation

In the context of decarbonisation, long-term energy scenarios play an important role to provide guidance to industry and policymakers. The debate about future energy systems, is often characterized by biases and belief systems rooted in broader public perceptions as opposed to expert insights and data (Bloomfield et al. 2021). Since the beginning of long-term energy planning, nuclear power has played a particularly important role, both due to expected technical progress, and the difference between expected costs and real cost developments. At the moment, another wave of technological forecasting expecting “advanced nuclear” to play a major role in decarbonised energy systems. However, recent paper from the Integrated Assessment Modelling community and scenarios with updated cost assumptions of renewables, in particular for solar photovoltaics and system integration costs, point in the opposite direction, i.e. that due to high costs, nuclear power is phased out in the coming decades (e.g.,Bogdanov et al. 2021). In this paper, we screen Scenarios of Integrated Assessment models based on the IAMC 1.5°C Scenario Explorer (Huppmann, Daniel et al. 2019) and the AR6 Scenario Explorer (Byers, Edward et al. 2022) to their assumptions on nuclear power, and their translation into relative and absolute contributions. In addition, these results are compared with energy scenarios of major international institutions and independent research teams. We identify two groups (1) with an increased share of nuclear; this group includes international organisations, also the IPCC with its IAM scenarios and the IEA with their NetZero by 2050 Scenarios; while (2) other consistently find a decreasing share of nuclear power, leading to very high shares of renewables. We conclude the need for a critical assessment of long-term scenarios, both with respect to cost assumptions of nuclear power and other variables, and the modelling of a largely decarbonised energy system.

Methods

We screen 409 Scenarios of 24 Integrated Assessment models based on the IAMC 1.5°C Scenario Explorer (Huppmann, Daniel et al. 2019) and 822 Scenarios of 84 Integrated Assessment models based on the AR6 Scenarios Database hosted by IIASA (Byers, Edward et al. 2022) to their assumptions on the development of nuclear power, and other elements of the energy system, and how these translate into relative and absolute contributions of nuclear power in long-term decarbonisation scenarios. We provide an in-depth analysis of those different energy scenarios based on the IAMC 1.5°C Scenario Explorer (Huppmann, Daniel et al. 2019) and data with regards to their pathways in the share of nuclear power over time and of the AR6 Scenarios. We cluster these scenarios and compare their underlying models as well as assumptions mainly with regard to CAPEX. In addition, these results are compared with energy scenarios of major international institutions and independent research teams publishing global scenarios.

Results

We find that in the universe of ambitious long-term decarbonisation scenarios, two groups can be clearly identified: (1) Some models conclude a rising share of nuclear, implying a steep increase in absolute power plant capacities; this group includes international organisations (IAEA 2020), also the IPCC (2018) with its IAM scenarios and the IEA (IEA 2021a) with their Net Zero by 2050 Scenarios with the highest nuclear projection since IEA history; while (2) other models consistently find a decreasing share of nuclear power, leading to very high shares of renewables. Figure 1 shows that the former group forecasts a slightly rising relative share of nuclear, which – given steeply rising electricity demand – implies a steep increase in nuclear power plant capacities. On the contrary, the decline of nuclear in the other group is linear until 2050/2060. Interestingly, some scenarios forecast a "rebound effect" after 2060, whereas in the larger subgroup nuclear phases out by 2060.

At present, we are analysing the first group of scenarios with respect to their assumptions. In general, assumptions of cost digression for nuclear are very optimistic, whereas they are rather pessimistic on renewables costs. Nuclear is often modelled as a baseload technology because flexibility options for renewables-based systems are underestimated. Also, we find an inconsistency in the International Energy Agency`s (IEA) annual World Energy Outlook (WEO): The highest value scenario for nuclear power is estimated by the current Net Zero Emissions scenario (NZE) of the IEA, which at the same time confirms that nuclear power is the most expensive way to provide electricity (IEA 2021b), which is confirmed by independent market analysts (Lazard 2021). We conclude the need for a critical assessment of long-term scenarios, both with respect to cost assumptions of nuclear power and other variables, and the modelling of a largely decarbonised energy system.

Session 11:15 – 12:15
Statistical approaches for energy economics

Room: CHE/184
Chair: Felix Jakob Fliegner

Shazam for the power sector - Application of Fourier transformation to unravel energy portfolio intermittency in the European power system
Felix Jakob Fliegner, TU Dresden

Simulation of Germany's security of supply: long-term forecasting of electric load profiles using machine learning
Benedikt Prusas, HS Düsseldorf

The financialization of the European futures market for carbon emission allowances
Tom Dudda, TU Dresden

Shazam for the power sector - Application of Fourier transformation to unravel energy portfolio intermittency in the European power system

Felix Jakob Fliegner[1]

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Keywords: Fourier analysis, power system flexibility, renewable energy integration, statistical analysis

Motivation

With rising levels of electrification in the EU power system, the impact of intermittent wind and solar power generation on swings in the residual load is expected to increase. This presentation demonstrates the implementation of a Fourier transformation to disentangle drivers of volatility from a high-level systems planning perspective and what flexibility needs arise from it. At the example of solar PV, and wind, timescales of significant oscillations are identified both individually and in portfolios of different countries. Depending on the relative shares of RE technologies to each other, volatility “fingerprints” can be found in the frequency spectrum per country. As a first of its kind, this work spans across the entire continent and includes offshore wind to the analysed technologies.

Methods

For this analysis a statistical analysis is performed with help of Fourier. Fourier analysis describes a mathematical analysis being applied to oscillating time series data, which allows disentangling major oscillations from minor ones. It is following the notion, that any kind of oscillator may be replicated by a set of periodical (co-) sinuses, where each sinusoid describes one “layer” of oscillation with a specific frequency, amplitude and phase. Oscillations with large amplitudes are more influential on the volatility of the original signal and therefore shape its total oscillation pattern the most. Their frequency indicates how often a given oscillation repeats itself over time. Phase angles are useful to assess; whether superimposed oscillations form a more constructive (amplifying) or destructive (damping) interference, i.e. if two “layers” of oscillation occur simultaneously or not.
In context of this study, Fourier is applied to a dataset of hourly availabilities of RE sources across Europe, based on PECD by ENTSO-E. The infeed is scaled up with capacity estimations from a TYNDP 2050 scenario. For the wide range of historical climate years, the Fourier analysis can then reveal re-occuring patterns of volatility from the past record and suggest how a 100% RE supplied

energy system of the future would behave in terms of volatility swings. To relate the native infeed to demand, a hypothetical demand dime series for 2050 is also generated based on MAF2030 values for the same set of climate years. In that way residual load curves can be studied and estimations on future flexibility needs are deducted. Finally, a correlation analysis of timeseries data reveals further insights in simultaneous events and smoothening.

Results

Major findings include a seasonal asynchronicity of PV and wind generation, reducing the season-long backup needs in Europe to a minimum. On a daily timescale, PV drives volatility the most and in combination with daily demand patterns it leads to strong day-night spreads of residual demand even in winter time. The volatility of wind energy in the medium term (weeks and months) is best addressed with geographical smoothening of non-correlated wind locations across the sea. An open-access python tool is made available to explore findings beyond what is discussed in this presentation. This presentation is based on a pre-print paper which handed in to Applied Energy.

Simulation of Germany's security of supply: long-term forecasting of electric load profiles using machine learning

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Keywords: long term forecasting, security of supply assessments, machine learning, artificial neural networks, gaussian process regression

Motivation

With the reduction of fossil fuels and the extended use of fluctuating renewable energies in the power grid, the importance of assessing future supply reliability is increasing as the power grid transforms.

Simulations to assess the security of supply require boundary conditions, such as the power demand. These are needed in an hourly resolution, but over a period of decades. Realistically modeling the boundary conditions at such high temporal resolution over long time horizons is a challenging task. The use of standard load profiles is common but limited. Therefore, we investigate the use of different machine learning techniques.

Methods

We examine multiple recurrent neural network architectures for autoregressive time-series forecasting. For non-autoregressive modeling, we consider ordinary feed-forward networks and Gaussian process regression with custom kernel functions. We evaluate these methods for the prediction of the total grid load of Germany by comparing the accuracy using the mean absolute percentage error (MAPE). Additionally, factors such as interpretability and uncertainty estimation are considered.

Results

The results show that recurrence is not necessary and even disadvantageous for this application. The network load of an hour is largely independent of the previous hour, and the error propagation is drastic for autoregressive forecasts. A significant part of the network load can be forecasted exclusively on the basis of calendar information, which means that a MAPE of 2.3 % can be achieved. The MAPE can be further reduced to 2.0 % by including weather data.

The financialization of the European futures market for carbon emission allowances

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Keywords: carbon futures, financialization, mixed data sampling, R-squared decomposition

Motivation

As well researched by the academic literature, the financialization of traditional commodity markets has fundamentally changed their behavior over the past two decades. With the European Union Emissions Trading Scheme (EU ETS), a new commodity market for carbon allowances was created in 2005. The bulk of carbon allowances trading takes place through derivatives, particularly forward and futures contracts. As freely traded on exchanges, this novel asset class naturally attracts the interest of financial investors seeking new risk-return profiles and diversification opportunities, which makes the EUA futures market prone to financialization. Emission allowances pose one of the main tools of the European Union to tackle global climate change. Based on the carbon price, firms decide whether to invest in less carbon-intensive technologies and sell emission allowances, or whether buying them and not reducing emissions is more economical - at least that is the theoretical intention of a carbon trading scheme. Thus, understanding what drives price movements of EUA futures is of pivotal importance - assuredly also to financial investors - but first and foremost to policymakers trying to cost-efficiently lower greenhouse gas emissions of the economy.

Methods

To measure the degree of financialization present in the market for European carbon emission allowances, we first identify fundamental variables that should drive the prices of EUA futures. Afterward, we regress returns and volatility of EUA futures on their fundamental drivers and variables serving as indicators for the influence of financial investors. Using R-squared decomposition, we investigate to what extent financial investors affect prices of EUA futures in relation to their fundamental drivers and how this relationship has changed over time. More specifically, we show how the contribution of each group of drivers to the explanatory power of the regression model evolves from trading phase II through the beginning of phase IV of the EU ETS, thereby indicating the degree of financialization of the European carbon futures market.

Results

Our results indicate emerging financialization as the importance of financial variables for explaining the variation in EUA futures returns increases over recent years.

Keynote 13:30 – 14:15

Room: CHE/S91, hybrid
Chair: Prof. Dr. Christian von Hirschhausen

Flexibility in infrastructure markets - A multi-level perspective

Prof. Steven A. Gabriel, PhD [1]

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Abstract
Infrastructure markets such as power, water/wastewater, natural gas, and transportation have seen a rise in flexibility options. For example, in electricity markets, due to intermittent renewable power generation (e.g., wind and solar), demand response and other load-shifting/load-curtailment options are an important part of the supply-demand profile. In wastewater, advanced wastewater treatment plants have the options of converting their waste to biogas, fertilizer (biosolids), or power (from methane) and should choose the right flexibility option for their and society's needs. In river systems, downstream users can pay upstream ones a market-based fee to improve the efficiency of upstream infrastructure to allow more water/less pollution downstream. In natural gas, destination-free liquefied natural gas (LNG) ships can take advantage of the best destination market prices. In transportation, flow-based pricing can give drivers the flexibility of trading off time and money. These are some important examples where flexibility has an important value. In this talk, we present several examples of infrastructure flexibility from a single-level and multi-level game theory perspective based on recent research and propose that this is a new paradigm for infrastructure systems.

Session 14:20 – 15:20
Energy efficiency and environment

Room: CHE/S91, hybrid
Chair: Maximilian Happach

Ecological footprint-environmental regulations nexus: The case of the Union for the Mediterranean
Burak Erkut, Bahçeşehir Cyprus University

Municipal networks for mutual support: How can this contribute to the implementation of energy efficiency measures?
Uta Burghard, Fraunhofer ISI

Determinants of energy intensity in Turkish manufacturing industry
Umut Erksan Senalp, Trakya University

Ecological footprint-environmental regulations nexus: The case of the Union for the Mediterranean

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Keywords: environmental regulations, environment patents, ecological footprint, trade, energy consumption

Motivation

Environmental regulations-ecological footprint nexus started to occupy an important space in the current debate of energy economics. Especially as a counter measure to environmental degradation, implementing environmental regulations remained on the agenda of scholars and policymakers alike, but whether these regulations actually have a reducing impact on ecological footprint remain open since the literature on the topic, and empirical evidence, remains fragmented and dissimilar. The current approach aims to investigate this for 5 member countries of the Union for the Mediterranean with panel data econometric techniques.

Methods

Panel data from France, Italy, Portugal, Spain, and Türkiye will be considered for 1992-2015, and will be tested for cross-sectional dependence, unit roots, and cointegration. Panel fixed effect regression estimations will be presented, also with Newey-West and Driscoll-Kraay standard errors. In addition, a country-level analysis will be conducted by using fully modified ordinary least squares estimation.

Results

The results indicate that overall only energy consumption and trade (measured as a percentage of GDP) matter for environmental footprints, but not environmental regulations. Country-level analysis indicate that there is a divergent situation among the 5 member countries.

Municipal networks for mutual support: How can this contribute to the implementation of energy efficiency measures?

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Keywords: energy efficiency, municipalities, networks, heating and cooling

Motivation

Municipalities play a crucial role in the transition to a low-carbon society. This is not only due to their major contribution to greenhouse gas emissions mainly through the energy consumption of buildings and transportation (Strasser et al. 2018) but also due to the dominant role of urban political actors and decision makers in the transition process (Cheung and Oßenbrügge 2020; Donnerer and Maraquin 2020; Heinelt 2017; Strasser et al. 2018). In recent years, climate and energy topics have moved more and more into the focus of municipal political agendas. Big drivers of the energy transition are the EU and global climate goals, National Energy and Climate Plans (NECPs) and networks like the Covenant of Mayors. Regarding energy and climate measures municipalities can be both: they can address their own property (e.g. refurbishing public buildings) or they can promote and create conditions to make energy and climate actions for local companies and residents more attractive (Burghard et al. 2019).

However, municipalities face a lot of challenges, including a variety of topics, targets, stakeholders, and market dynamics (Strasser et al. 2018). The PATH2LC project brings together municipalities on regional and international level to support them in the process of implementing their existing Sustainable Energy (and Climate) Action Plans (SEAPs / SECAPs). Five existing networks of municipalities in five countries (Portugal, Italy, France, Netherlands, and Greece) take over the implementation part of the project and are supported by scientific and dissemination partners. The core of the project is the 'Learning Municipality Network' (LMN) approach: very close cooperation of municipalities in the form of regular, well organised and moderated meetings including expert input and peer-to-peer learning.

In this abstract first results of the technical monitoring, i.e. the implementation status of measures defined in the climate plans, are presented.

Methods

The progress of each participating municipality and the LMN as a whole is monitored by the project team. Therefore, an annual survey is developed in which the implementation status of energy efficiency measures is collected. The monitoring can provide evidence of the effects achieved by the measures. In this abstract the results of the first monitoring from 2021 are presented.

Data collection:

The method is an online survey of participating municipalities in the Learning Municipality Networks (LMNs). The questionnaire was provided in national language and was completed by representatives of each municipality participating in the networks. The measures implemented were recorded, including energy savings, increase in the share of renewable energy and reduction in CO2 emissions. A total of 3 annual surveys are planned over a period of 3 years. Of these, one have been completed, of which the results are shown in this abstract.

Data analysis:

For the evaluation, the survey entries were reviewed manually and, if possible, missing information was added. For example, for many measures, the measure category could be added based on the short description of the measures.

A detailed evaluation at the level of individual municipalities is not possible due to the low response rate in the first monitoring. Therefore, the measures are evaluated at the level of all LMNs together. The same applies to evaluations of the individual measure categories and the baseline for the savings calculation.

Results

In total 301 measures were reported in the survey, of which 235 measures are part of a SECAP and 40 measures are not part of a SECAP. The results show that measures have been implemented continuously over the last few years. Especially since 2018, the number of implemented measures has further increased (Figure 1).

As shown in Figure 2, efficiency measures and measures regarding renewables are often implemented. Fewer measures were implemented in the area of heating and cooling, building retrofitting or social measures like stakeholder engagement.

It should be noted again, that savings were not indicated for all measures. However, it can still be seen that especially a few measures in the area of renewables and heating and cooling can generate large savings (Figure 3).

Most savings and also most measures were implemented in the electricity and transport sectors. This shows that there is still potential for further savings measures, especially in the area of heating and cooling.

In sum, it can be seen that measures have been implemented continuously over the last few years. Nevertheless, for many of the measures, no information is available on savings or energy sources. Most of the measures implemented are from the category of efficiency or renewable energies. It can be seen that especially a few measures in the area of renewables and heating and cooling can generate large savings.

Determinants of energy intensity in Turkish manufacturing industry

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Keywords: energy intensity, firm-level analysis, panel data

Motivation

The increase in the energy need of the growing manufacturing industry is considered as a problem by policy makers, since Turkey is an energy dependent country. The energy dependency has a negative impact on both energy security and trade deficit, which is one of the chronic problems of the Turkish economy. Therefore, in order to reduce energy consumption in manufacturing and service sectors, the energy efficiency law was enacted in 2007, the Energy Efficiency Strategy Document was prepared in 2012, and similarly, the National Energy Efficiency Action Plan was put into practice in 2018. The purpose of these policies is to reduce energy intensity (increase energy efficiency) and reduce energy consumption in transportation, manufacturing, services and agriculture. In this context, firms are provided with incentives and supports to increase energy efficiency. Despite the attempts of policy makers to define strategy to decrease energy intensity at the sector and firm level, there is no study in the relevant literature that determines the factors determining the energy intensity of firms operating in the Turkish manufacturing industry. The Vision, Main Objectives and Principles of the 11th Development Plan highlights the importance of energy efficiency. Our aim is to present a roadmap that can be used by the policy makers who implement the goal of reducing energy intensity in manufacturing industry.

Methods

In our paper, the determinants of the energy intensity of firms operating in Turkish manufacturing industry between 2003 and 2015 will be determined by using the firm-level Annual Industry and Service Statistics which is provided by the Turkish Statistical Institute. Our analysis will be carried out with the Fixed Effects method, which takes firm heterogeneity into account, and the Generalized Moments Method (GMM) will be used to control potential endogeneity in order to test the robustness of the findings.

Results

We aim to shed lights on the effect of firm charactersitics on a firm's energy intensity. Our preliminary results show that research and development expenditures, and firms' foreign ownership structure are the principal determinants of energy intensity in Turkish manufacturing.

Session 14:20 – 15:20
Renewables in transportation systems

Room: CHE/S89, hybrid
Chair: Bjarne Steffen

The competition of zero-emission vehicle technologies in road freight

Bjarne Steffen, ETH Zurich

Reviewing comparative life cycle assessments for battery electric vs. internal combustion engine vehicles for passenger cars

Christina Kockel, RWTH Aachen University

The role of public investment in building up a public electric vehicle charging grid

Marie-Louise Arlt, LMU München

The competition of zero-emission vehicle technologies in road freight

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Keywords: transport sector, freight, e-mobility, hydrogen, technology competition

Motivation

Commercial road-freight vehicles play an important role in decarbonizing the transport sector (Noll et al., 2022). In the passenger vehicle sector, a transition to zero-carbon drive-technologies is not only imminent, but the transitional technology itself is largely determined—battery electric vehicles (EVs) are poised to corner the market (IEA, 2020). Though we expect a similar transitional timeline to follow in the commercial vehicle sector, it remains uncertain which specific low-carbon technologies (e.g., battery electric or hydrogen fuel cell) will become prevalent, at what time, and in which specific applications. To address this uncertainty we develop a system-dynamics model to project the competition of technologies for road-freight vehicles. We represent different market segments and global regions, which are linked through technological and geographical spillovers. The outputs of this model offer both the market share forecasts themselves as well as a comprehensive analysis tool, with which policy makers may use for evaluation of appropriate intervention points to assess the energy transition in the road freight sector.

While there exist a handful of models that project market shares of road-freight vehicle drive-technologies, they are largely nationally or sub-nationally focused, consider only select vehicle drive-technologies, and do not include the effects of cost reductions from endogenous capacity deployment or technology advancements in outside markets (Fulton et al., 2009; ICCT, 2012; Seitz and Terzidis, 2014). We address these gaps by modeling a number of drive-technology options in specific application segments and global regions to capture positive feedback from experiential learning and exogenous market spillovers as well as to consider key global markets, namely the EU, the US, China, India and Brazil, which offer further insights into the future development and prevalence of alternative drive-technologies.

Methods

At the core of the model are the following key insights: competition between drive-technologies is modeled by way of investor simulation and the resulting endogenized system feedback. First, we assess the initial degree of competition between drive-technologies (i.e. diesel, battery-electric,

fuel cell electric, etc.) in different application segments (i.e. light-duty urban, heavy-duty long-haul) by comparing the total cost of ownership (TCO) of a vehicle (Noll et al., 2022). A probabilistic discrete choice simulation of independent investors then determines the selection of specific drive-technologies. It is assumed that the drive-technology with the lowest TCO would be the most attractive to a rational commercial investor.
Next, investor simulation and selection enables endogenized system feedback. Market share diffusion of low-carbon drive-technologies is dependent upon experience curve-based cost projections (Nykvist and Nilsson, 2015; Schmidt et al., 2017). Technology costs move down along their respective experience curves when total deployment capacity is increased due to larger market shares (Arthur, 1989; Mowery and Rosenberg, 1979; Schmidt et al., 2016). Similarly, exogenous feedback from external market spillovers also drives down costs along their experience curves (Beuse et al., 2020). Deployment of lithium-ion batteries, for example, in other prominent sectors, such as passenger EVs or stationary storage, extends the maturity of the technology and thus “spills over” to the road-freight sector by way of reduced battery costs.

Results

Our preliminary results show high market share projections of battery electric drive-technologies. For application segments with higher operating expenditure, such as low- or medium-duty application segments with lower energy storage capacities, competitiveness of battery electric vehicles is apparent already within the next five years. For application segments with higher capital expenditure, such as heavy-duty long haul segments with large energy storage requirements, high market shares of battery electric vehicles are realized later. Spillovers between modeled segments and regions as well as from exogenous markets seem highly relevant. We discuss these results’ implications for policy makers and sustainability transitions modelers. To enable the low-carbon transport transition in the road-freight sector, assistance from policy-makers is paramount—market forces alone will not suffice, especially in global regions where existing high-emission vehicles are cheap and low-emission charging infrastructure sparse. Strategic policy intervention is therefore required.

Reviewing comparative life cycle assessments for battery electric vs. internal combustion engine vehicles for passenger cars

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Keywords: GHG-emissions, transport sector, electromobility, life cycle assessment, sensitivity analysis

Motivation

The EU's commitment to climate neutrality by 2050 implies a transformation in all sectors. As outlined in the recent report of the European Energy Agency, this includes a 90 % reduction of greenhouse gas (GHG) emissions from transportation compared to 1990 levels (EEA, 2022). According to the report, one-fourth of the EU's total GHG emissions is attributable to the highly fossil-based transportation sector in 2019. Road transport causes the highest share with more than 70%, whereof individual passenger cars contribute the most (61%) (EEA, 2022). Policymakers consider the switch from internal combustion engine vehicles (ICEVs) to battery electric vehicles (BEVs) as a key component toward climate neutrality, which has thus shaped current developments in the automotive industry. From an environmental perspective, the motivation is primarily to reduce emissions from driving by substituting GHG-intensive diesel and petroleum with electricity primarily generated from renewable energy sources (RES). However, since the share of RES in the power grid fluctuates depending on the weather, the potential environmental advantages of BEVs over ICEVs strongly depend on the time and location of charging. Therewith, currently charging strategies can be an enabler for a low-carbon market diffusion of electric mobility.

As outlined in Buberger et al., 2022, however, focusing on operational emissions while neglecting other life-cycle phases poses an incomplete picture of the ecological consequences of the paradigm shift from ICEVs to BEVs. Therefore, to compare the comprehensive environmental impacts of ICEVs and BEVs, the Life Cycle Assessment (LCA) method has been extensively applied in many studies. Although this method is a standardized approach, literature on the environmental benefit of BEVs compared to ICEVs shows a broad range of both total results and environmental break-even points.

Methods

With the overarching aim to provide clarity on the causes of the disparate results, the purpose of this work is two-fold. First, the results of existing comparative LCAs of ICEVs and BEVs are outlined and discussed based on underlying assumptions and input parameters for modelling. Secondly, the most sensitive parameters across the life-cycle phases for each vehicle technology are identified to conduct a sensitivity analysis.

Data for this study were collected through a literature review. Since vehicle operation is the most sensitive life cycle phase, the limitations of the review are set on LCA studies considering Germany as the country of vehicle operation. The study is further focused on comparing ICEVs, distinguished between the fuel type petrol (ICEV-p) and diesel (ICEV-d), to BEVs. Other vehicle technologies, e.g., plug-in hybrid or fuel cell vehicles, are out of scope and therefore excluded from the analysis. To quantify the impact of the most influential parameters, an LCA for different vehicle classes and powertrains is conducted. The chosen sensitivity parameters are identified from the literature review and are varied by +/- 10 %.

Results

Figure 1 illustrates the results of analyzed studies from 2010-2022, showing the global warming potential (GWP) over the lifecycle of a vehicle. Overall, there is a broad range of both resulting footprints per technology as well as the environmental break-even point. Assuming the respective electricity mix of Germany for the modelled years 2015-2020, results on the total footprint of vehicles show an average GWP of 27 tCO2-eq./vehicle for BEVs, with a range between 17.5-40.0 tCO2-eq./vehicle. For ICEV-p, the average is 43.5 with a range between 32.0-60.5 tCO2-eq./vehicle. In all studies, the impact of the production phase is overall higher for BEVs but can be offset by the lower carbon emissions during the use phase. Regarding the production phase, the energy-intensive production of the battery, and thus the battery capacity and the electricity mix used for production, are key influencing factors.

For the use phase, the total mileage over the entire lifecycle, the specific consumption, the electricity mix used for charging and the share of urban driving are most relevant. To show the average deviation from the total GWP, a sensitivity analysis is conducted by increasing the selected parameters by 10 %. As displayed in Figure 2 and Table 1, conclusions are derived in which directions results of LCA studies can deviate depending on the underlying assumptions.

Key insights gained from this study include the following:

- the higher the total milage and specific consumption per vehicle, the lower the timespan of reaching the environmental break-even point between BEV and ICEVs
- an increased GWP of the electricity mix negatively influences the impact of BEVs

- the higher the share of urban driving, the lower the impact of BEVs and the higher the impact of ICEVs

Overall, the paper sheds a light on important factors to consider within the LCA modelling of vehicles and provides a guideline for interpreting LCA results.

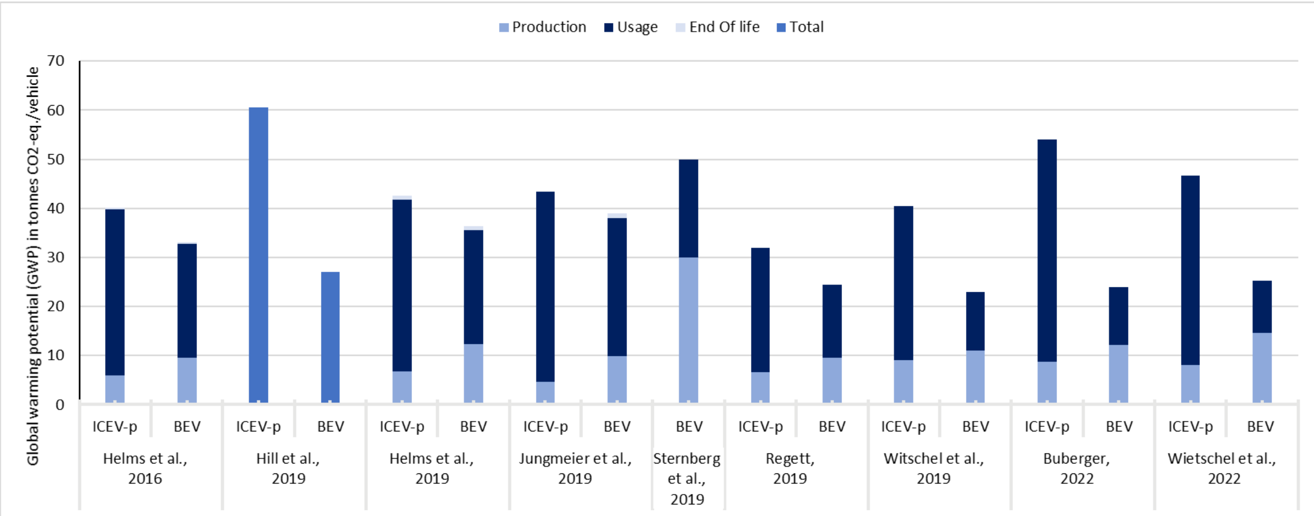

Figure 1: Total global warming potential (GWP) per vehicle, literature review on comparative LCAs of ICEVs and BEVs, German cases

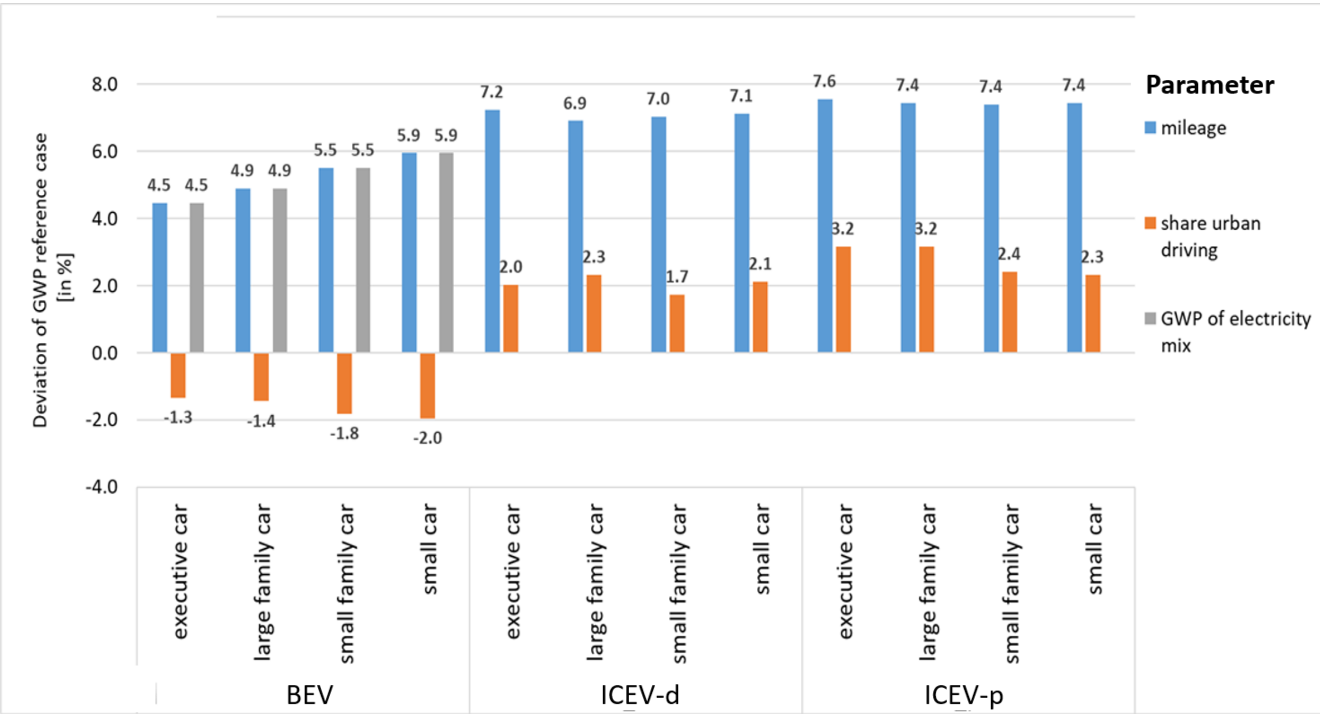

Figure 2: Results of deviation from GWP of reference case when increasing parameters by 10%

Table 1: Sensitivity analysis of parameters in the use phase and the average deviation GWP compared to a reference scenario

Parameter for sensitivity analysis	Average deviation of GWP compared to the reference scenario			Conclusion
	BEV	ICEV-p	ICEV-d	
Higher total mileage over the lifespan (+10%)	~+5.2%	~+7.5%	~+7.0%	The higher the total mileage of a car, the higher the environmental benefit of a BEV
Higher consumption compared to manufacturer data (+10%)	~+5.2%	~+7.5%	~+7.0%	The higher consumption of a car, the faster BEV break environmentally even with ICEV
GWP of electricity mix for charging (+10%)	~+5.2%	0.0%	0.0%	The higher the THGE of the electricity mix for charging, the later BEV break environmentally even with ICEV (and vice versa with lower emissions)
Share of urban driving (+10%)	~ -1,6%	~+2.0%	~ +2.8%	A higher share of urban driving leads to environmental benefits of BEV and at the same time disadvantages of ICEVs

The role of public investment in building up a public electric vehicle charging grid

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Keywords: electric vehicles charging grid

Motivation

The transition from conventional cars to electric vehicles requires a suitable public charging infrastructure. In this paper, I investigate the role of direct public investment - such as by municipality-owned utilities - in building up a charging grid. Leveraging cities and counties in Germany as relevant charging markets, I investigate three hypotheses: whether public investment is associated with a denser charging network; whether public crowds out private investment; and whether public investment crowds out attractive charging spots.

I use the German charging market as a case study. In Germany, the number of electric vehicles has steadily been increasing. Municipalities have further a general interest in developing local transportation infrastructure and are in charge of issuing permits for charging stations in public space. Thus, they have considerable control over the approaches being taken for the development of the local public charging grid. One of the significant decisions they may take is whether they request a locally-based and publicly-owned utility (i.e. "Stadtwerk") to build up a charging network if such a utility is available – or whether they leave the establishment of the grid to third parties, possibly supported by other economic policies.

Methods

Public procurement of a charging grid through a publicly-owned utility might, however, have an ambiguous effect on the density and quality of the network. On the one hand, it is known that the establishment of the charging grid suffers from a chicken-and-egg problem where the market may get stuck in a low-adoption equilibrium under uncertain demand for and supply of charging (Zhou and Li 2018). Public procurement could overcome this equilibrium by fiat, thereby generating higher electric vehicle adoption, and eventually triggering private investment. On the other hand, such public investment could occupy the most attractive charging spots and, through its potential market-shapening impact (subsidized pricing,

To identify the effect of public investment, I leverage the fact that 1) some municipalities charged publicly-owned local utilities (e.g. a local "Stadtwerk") to engage in the charging market while other municipalities did not; 2) some municipalities own utilities which can be used as a vehicle for direct investment into charging, while others do not. I use data provided by the Bundesnetzagentur on charging stations across Germany as well as electric vehicle registrations as provided by the Kraftfahrtbundesamt and the RWI GRID data. I further leverage utility ownership data provided by Orbis.

Results

Preliminary descriptive results indicate that municipalities in which publicly-owned utilities are active in the charging market have a denser charging network, at least in earlier stages of the development. I further find indication that such public investment might be associated with a negative impact on private investment and that public investment targets charging spots closer to the city center, than private investment.

Session 14:20 – 15:20
Hydrogen and impact on electricity transport infrastructure

Room: CHE/183
Chair: Martin Lieberwirth

Hydrogen electrolysis and electricity networks – What to support, what not?

Friedrich Kunz, TenneT TSO GmbH

Benefits of a hydrogen network in Europe with repurposed gas pipelines

Fabian Neumann, TU Berlin

Decarbonizing the industry sector and its effects on electricity transmission grid operation – implications from a model based analysis for Germany

Martin Lieberwirth, TU Dresden

Hydrogen electrolysis and electricity networks – What to support, what not?

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Keywords: electricity network, hydrogen electrolysis, support scheme, energy economics

Motivation

System integration is seen as the core of a future decarbonized and renewable energy system. Following the European system integration strategy, "energy system integration" refers to the planning and operating of the energy system “as a whole”, across multiple energy carriers, infrastructures, and consumption sectors, by creating stronger links between them (EC, 2020). In this context, hydrogen is often seen as important part as the energy carrier is versatile and can be used in different sectors and applications. For some industrial applications, it is the only technical viable option, like feedstock in chemicals or steel making. While in other sectors and applications, like transport or buildings, hydrogen is only one option among other solutions, like heat pumps.

On the one hand, increasing electrification of energy demands, both directly as well as indirectly through hydrogen, impacts electricity networks on the demand side and increases transport needs towards load centers. On the other hand, those demands need to be matched with renewable energies, predominantly from wind (onshore and offshore) and solar, which also need to be integrated in the energy system through the electricity network. Therefore, the role of an electricity transmission system operator gains more importance.

While hydrogen electrolysis is only one influencing factor, it is seen as important due to recent political ambitions as well as the need for further support. E.g. on EU level, initial political ambitions of 40 GW domestic electrolysis capacity by 2030 were recently increased to 10 Mt of domestic hydrogen production (roughly 170 GW) with the REPowerEU plan (EC, 2022). In Germany, recent political ambitions are 10 GW electrolyser capacity by 2030, while current scenarios of the national grid development plan prospects 68 GW by 2045. The challenge at hand is, how to foster the ramp-up of innovative hydrogen technologies, while ensure an efficient integration into the energy system.

Methods

In a first step, we reflect on the experiences with renewable support and discuss those, in a second step, in the light of a potential hydrogen support schemes. In particular we focus on are: (1) the value of auctions in support innovations, (2) the focus of the support scheme in the light of different stages of the value chain and different application options for hydrogen, (3) the aspect of technology neutrality for hydrogen production, (4) the type of support to ensure a flexible and system-oriented operation, (5) the spatial aspects and requirements of hydrogen production, and (6) the potential contribution to ancillary services. While we will mainly draw upon qualitative considerations, we support this with quantifications where possible.

Results

The results of our analysis can be summarized as follows. Firstly, support shall address specific applications to account for the "energy efficiency first" principle and thereby to make best use of limited RES capacities, especially in Germany. Moreover, hydrogen support shall be technology-neutral and promote a level-playing field. By this market efficiency can be increased and innovations can be fostered. Thirdly, support should be primarily investment-based to incentivize a flexible operation in line with needs of the system. Hydrogen production should be considered as a flexibility source to react to price signals and ensure production especially in times of high renewable surplus and lower market prices. Fourthly, a smart integration of hydrogen production with other stages of the value chain should be ensured as it is systemically beneficial. Among other options, an indirect combination of an electrolyser with renewables, i.e. common investments in RES and electrolyser capacities, should be aimed at. By this, electrolyser capacities can be located centrally to account for infrastructure needs while they are in close proximity to RES capacities and generation surpluses. Fifthly, support shall explicitly account for locational aspects to avoid additional infrastructure expansion needs. Finally, electrolysers can contribute to ancillary services and thereby should be incentivised to provide their potential. These features can help to address the system challenges while the required support of these innovative technologies is ensured and the ramp-up of the hydrogen economy is fostered.

Benefits of a hydrogen network in Europe with repurposed gas pipelines

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Keywords: hydrogen backbone, sector-coupling, PyPSA, energy infrastructures, retrofitting

Motivation

Electricity transmission expansion has suffered many delays in Europe in recent decades, despite its importance for integrating renewable electricity into the energy system. A hydrogen network which reuses the existing fossil gas network would not only help supply demand for low-emission fuels, but could also help to balance variations in wind and solar energy across the continent and thus avoid power grid expansion. The European gas industry has actively publicised this vision in a series of European Hydrogen Backbone reports. However, their outlook is not backed by a co-optimisation study of energy infrastructures.

Methods

We investigate this idea by varying the allowed expansion of electricity and hydrogen grids in net-zero CO2 scenarios for a sector-coupled European energy system with high shares of renewables and self-sufficient supply. We cover the electricity, buildings, transport, agriculture, and industry sectors across 181 regions and model every third hour of a year. With this high spatio-temporal resolution, we can capture bottlenecks in transmission and the variability of demand and renewable supply which is important to assess infrastructure trade-offs.

Results

Our results show a consistent benefit of a pan-continental hydrogen backbone that connects high-yield regions with demand centers, synthetic fuel production and geological storage sites. Developing a hydrogen network reduces system costs by up to 6%, with highest benefits when electricity grid reinforcements cannot be realised. Between 58% and 66% of this backbone could be built from repurposed natural gas pipelines. However, we find that hydrogen networks can only partially substitute for power grid expansion, and that both can achieve strongest cost savings of 12% together.

Decarbonizing the industry sector and its effects on electricity transmission grid operation – implications from a model based analysis for Germany

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Keywords: electricity grid modeling congestion management, hydrogen electrolysis

Motivation

With the latest federal election in Germany in late 2021, the newly formed government decided even to accelerate the deployment of renewable energies and increase the targeted renewable amounts aiming at renewable penetration levels up to 80% of the total electricity demand until the year 2030. Parallel to the decarbonization of electricity generation, green hydrogen is considered a favorable option to reduce carbon emissions in fossil fuel-intensive industries. While green hydrogen can be regarded as an essential pillar of the German energy transition, integrating large amounts of electrolyzer capacities poses particular challenges for system operators along the entire hydrogen value chain. The operation of electrolyzer capacities and production of green hydrogen imputes increased electricity demand, stressing electricity grids above the conventional electricity load level. Also, it requires a massive restructuring of the gas transportation and storage system. The question arises to which extent electrolyzer capacities cause additional grid bottlenecks and how a flexible operation of electrolyzers can contribute to efficiently managing future electricity grids. Since energy-intensive industries are distributed heterogeneously throughout Germany, the specific order in which they are decarbonized impacts the change of electricity loads and thus affects grid congestions differently. This research investigates the effects of the geographic distribution of electrolyzer capacities on the future transmission grid operation with a particular focus on how different decarbonization orders of specific industries impact individual grid bottlenecks and the efficiency of congestion management.

Methods

To investigate the impact of electrolyzer operation on the operation of transmission grids, the application of a fundamental electricity market model and scenario-based research is proposed. A scenario framework is created, representing a set of future electrolyzer infrastructures differing in the geographic distribution based on the decarbonization order of specific energy-intensive industries and the level of integration into congestion management practices. Especially the technology readiness level of industrial processes to utilize hydrogen effectively was taken into account for electrolyzer site selection. A linear transmission grid model for the German electricity transportation system, encompassing more than 500 grid nodes, is exploited to study interactions between hydrogen production and transmission grid operation in the target year 2030. The optimisation model comprises two stages: Wholesale electricity market clearing and grid operation optimisation. During the first stage, the cost-minimising power generation dispatch in the European electricity market at a market-zone level is determined in an hourly resolution for 8760 hours of a year to serve the market's demands. The operation of electrolyzer capacities is a direct model-endogenous result. The cost-minimising optimisation yields a dispatch schedule of electrolyzers in which hydrogen is produced during low price hours. In addition to specific technology dispatch, storage, and trade constraints, a pre-defined amount of total hydrogen production is enforced by the model for a year, assuming sufficient storage and transportation infrastructures. Both the hourly operation of the conventional and renewable generation and storage fleet and the operation levels of the electrolyzer capacities serve as input for the grid optimisation model. While the geographic distribution is not impacting the market-clearing dispatch at a market-zone level, it has a decisive impact on the operation of transmission grids. During the second stage, the grid model optimises the application of different congestion management measures, comprising the redispatch of domestic plants, the redispatch of hydrogen capacities, cross-border remedial actions, renewable curtailment, and demand-side applications to resolve grid bottlenecks resulting from the market-clearing dispatch in a cost-minimising way. In addition to the differences in the geographic distribution of electrolyzer capacities, two different operation modes are considered in the scenario framework, a flexible and non-flexible operation. A flexible operation allows for the active participation of electrolyzers in congestion management through load-shifting. During the non-flexible operation scenarios, the electrolyzers' imputed loads that are endogenously modeled during market-clearing cannot be adjusted to manage grid congestions. Like the market-clearing model, the optimisation of remedial actions is carried out in an hourly resolution for 8760 hours of a year but applying a rolling horizon modeling approach to handle the higher complexity due to the higher granularity of grid representation. The modeled remedial action and congestion volumes then serve as comparative benchmark indicators to evaluate different hydrogen infrastructures differing in the decarbonization order of energy industries and operation modes.

Results

Initial results of this research indicate that the operation of electrolyzer capacities, in general, affects the operation of the transmission system, significantly exerting a strong impact on congestion management results. But the geographic distribution of electrolyzer capacities assumed in the different scenarios heavily influences these results. Energy-intensive industries are distributed differently throughout Germany. For example, the large pulp and paper production and mineral processing facilities feature a more spatially widespread distribution than refineries, basic chemicals, and metal production facilities. As a result, the operation of electrolyzers impacts grid congestions differently. The spatially widespread deployment of electrolyzer capacities translates into higher congestion management volumes and thus integration costs. Therefore, the order in which those industries decarbonize significantly impacts the system integration of increasing electrolyzer capacities. Moreover, the participation of electrolyzer capacities in grid management, i.e. through load-shifting of electrolyzer capacities, can substantially counteract additional grid congestions resulting from hydrogen production, reducing total congestion management volumes and costs while preserving total hydrogen production levels. However, installing electrolyzers at more centralized industries reduces the required congestion management actions regardless of operation mode, due to the close proximity the renewable power generation capacities.

Session 14:20 – 15:20
Renewable auctions and financing

Room: CHE/184
Chair: Lisa Lorenz

Renewable procurement auctions and default: pre-qualification requirements

Silvester van Koten, CERGE-EI Prague

Market-financed large-scale solar power without support schemes?

Anurag Gumber, ETH Zurich

Preferential treatment in renewable energy auctions: an analysis of the reference yield model & German wind auctions

Prokop Čech, Jan Evangelista Purkyně University

Renewable procurement auctions and default: pre-qualification requirements

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Keywords: renewable procurement auctions, bidder commitment, pre-qualification requirements, bid-preparation costs, experimental economics, energy economics

Motivation

Support for renewable power plants is increasingly allocated with market-based methodologies using procurement auctions. While auctions are known to have attractive efficiency properties, experience shows that they have a significant drawback: Many renewable projects awarded in the auction are not actually implemented and realized. The literature suggests that the potential builders of renewable plants in their role as bidders may be overly optimistic about their future abilities and costs.

We specifically study two measures proposed for regulators/auctioneers to improve the performance of such procurement auctions, Financial Pre-Qualification (FPQs) and Physic Pre-Qualification (PPQs). Both measures require auction participants to make a commitment before the start of the auction. For the FPQ, the commitment takes the form of a financial bond that is returned when the project is implemented or when the bidder loses the auction. For the PPQ, the commitment takes the form of making a pre-investment by implementing a part of the project before the auction. The latter method is presently used for onshore wind auctions in Germany.

Methods

We use theory and numerical simulations to analyze and compare the performance of procurement auctions for support for renewable power plants. Using standard economic mathematical equations we calculate the equilibrium bidding behavior of bidders and derive formula for the key outcomes (such as expected bidder profits and expected auctioneer and government welfare). We illustrate the extent and size of the effects for different parameter values using numerical simulations. We are still in the process of preparing economic experiments.

Results

Our theoretical and numerical analyses indicate that the FPQ is vastly superior to the PPQ. Our outcomes indicate that a government that wants to allocate subsidies to (potential) renewable plant investors should not introduce Physical Pre-Qualifications (PPQ), but instead use Financial Pre-Qualifications (FPQ), as FPQ are superior to PPQ for all indicators. Moreover, our results indicate that the government should do its utmost to prevent the occurrence of sunk costs for potential investors.

Market-financed large-scale solar power without support schemes?

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Keywords: solar photovoltaic, power-market forecast, financial feasibility, carbon prices, subsidy free

Motivation

In recent years, investments in solar photovoltaic (PV) installations in Germany that are predominately aimed at self-consumption have benefited from prices achieving grid parity. Yet, bigger and larger solutions targeted at wholesale electricity markets are still often dependent on upfront subsidies and long-term PPAs that allow for longer and higher debt levels enhancing financial feasibility. While this public support model has worked for mainstreaming the technology for financial actors, at some point, much of the support would need to reduce as the scale of deployment increases manifold. However, intermittent technologies like PVs face a specific challenge: they are self-marginalizing i.e., their power prices significantly decrease in times of high PV feed-in, and these times are notably predictable on daily basis with low volatility by market participants, therefore presenting a potential to lock-in low prices in the long term. As such, this self-marginalizing attribute makes PV generation plants susceptible to financial infeasibility under pure market driven conditions in the long term. In such situation, we are resolved to estimate under what market conditions, especially under which CO2 prices, large-scale solar power will become market ready and profitable without support scheme. Accordingly, here we conduct an analysis of the European electricity market with focus on Germany using the Power ACE model to gauge evolution of wholesale prices and overlay the estimation on a utility-scale investment/financial model to examine feasibility of utility-scale PV plants.

Methods

The PowerACE simulation model is applied to determine long-run market prices covering period from 2020 to 2050 for five carbon scenarios ranging from €93/tCO2 to €350/tCO2 in year 2050. Unlike common approaches that minimizes long-run system costs, our model carries out investments on the expected profitability to agents thereby endogenizing investment decisions based on price forecasts on hourly demand and supply bids. In addition to the five scenarios, we also examine with 20% higher renewable generation from wind and solar in Germany, and with investments in carbon capture and storage (CCS) respectively.

The financial model is thereon developed to conduct detailed discounted cash flow analysis for a 50 MWp solar project-financed power plant. The model follows exogenous inputs related to revenues from PowerACE model, inputs related to tax and accounting from Bundesministerium der Finanzen, Germany, detailed investment costs from IRENA (2020), and other detailed inputs regarding operations, taxes, debt costs, from academic as well as widely cited industry sources. Finally, the model enables iterative calculation to control for the maximum debt a lender would provide the project to achieve minimum debt service coverage ratio (DSCR). This iterative calculation helps examine the realistic project level and equity level returns that would be attainable.

Results

What is remarkable in each of the PowerACE scenarios is that the market value factor, defined as average market value of the renewable technology vis-à-vis the baseload generator declines significantly for PV. Figure 1 depicts the wholesale price estimate and market value factor for different scenarios. As such, this leads us to examine the financial profitability of purely market led PV systems in situations when PV would not be as revenue attractive as other investments. Our findings suggest that having lower upfront investment cost, higher carbon price (figure 2), and/or higher tenure of debt have significant positive impact on the expected equity return and level of debt available. On the contrary, impacts of higher DSCR or debt interest rate are not as high. Hence, considering a pure market led investment where upfront subsidies are ruled out and long term PPAs may not be assured would result in mere ~50% debt levels with a 10-year tenure. Therefore, from a policy perspective we find that elongating the debt schedule without intervening in carbon prices or capital costs would be a plausible solution of increasing debt levels to 80% or more, as is the case with PV projects with assured PPAs and tariffs. In such case, for instance a publicly led debt guarantee mechanism could be useful in getting commercial banks to provide long term loans while having an insurance on their long-term commitment. Accordingly, our research aides in understanding the future capacity potential of PV in Germany and raises inquiry for future research on which market led policy solutions can potentially address the biggest risks prevalent in any utility-scale PV investment decision.

Figure 1: Spot electricity prices (above) and market value factor for PV (below) simulated with PowerACE

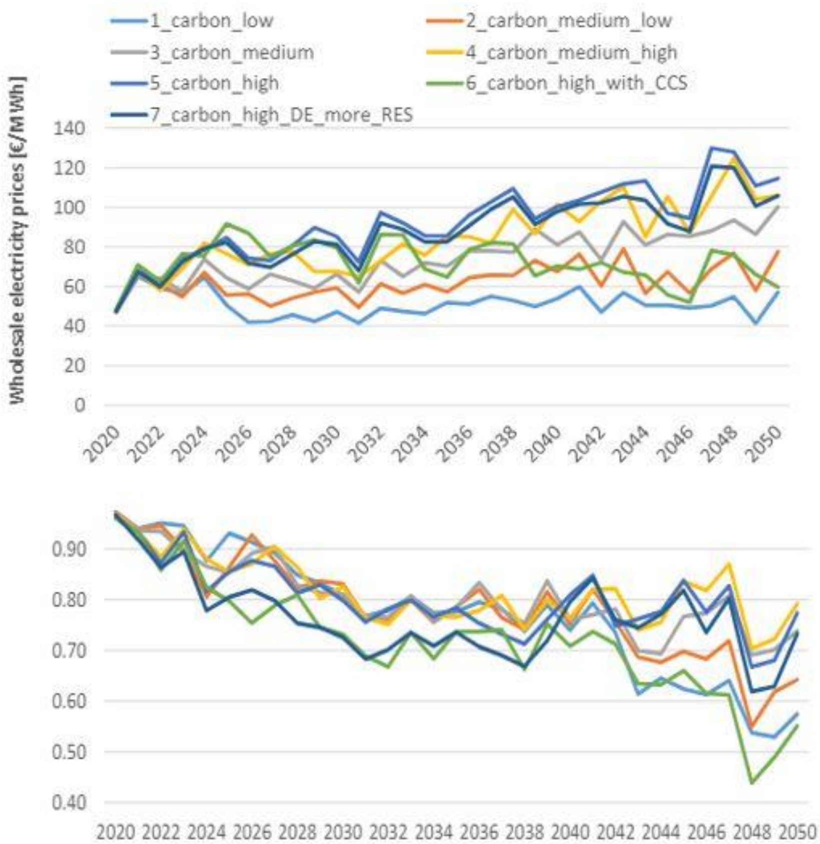


Figure 2: Carbon price impact on project debt and equity returns

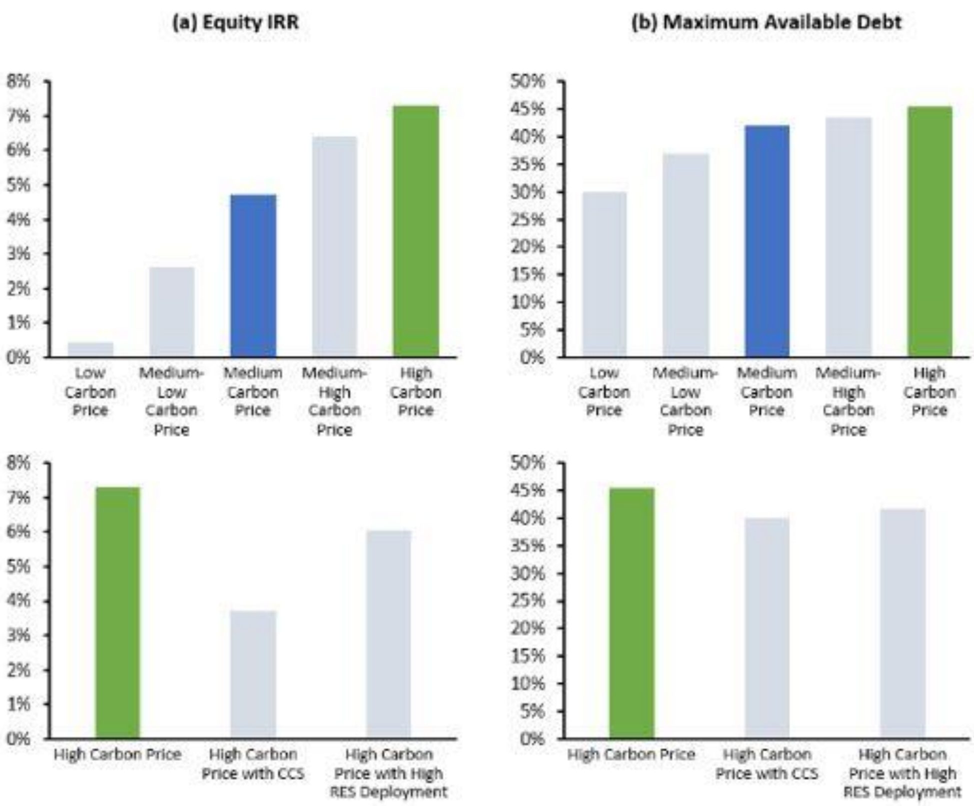
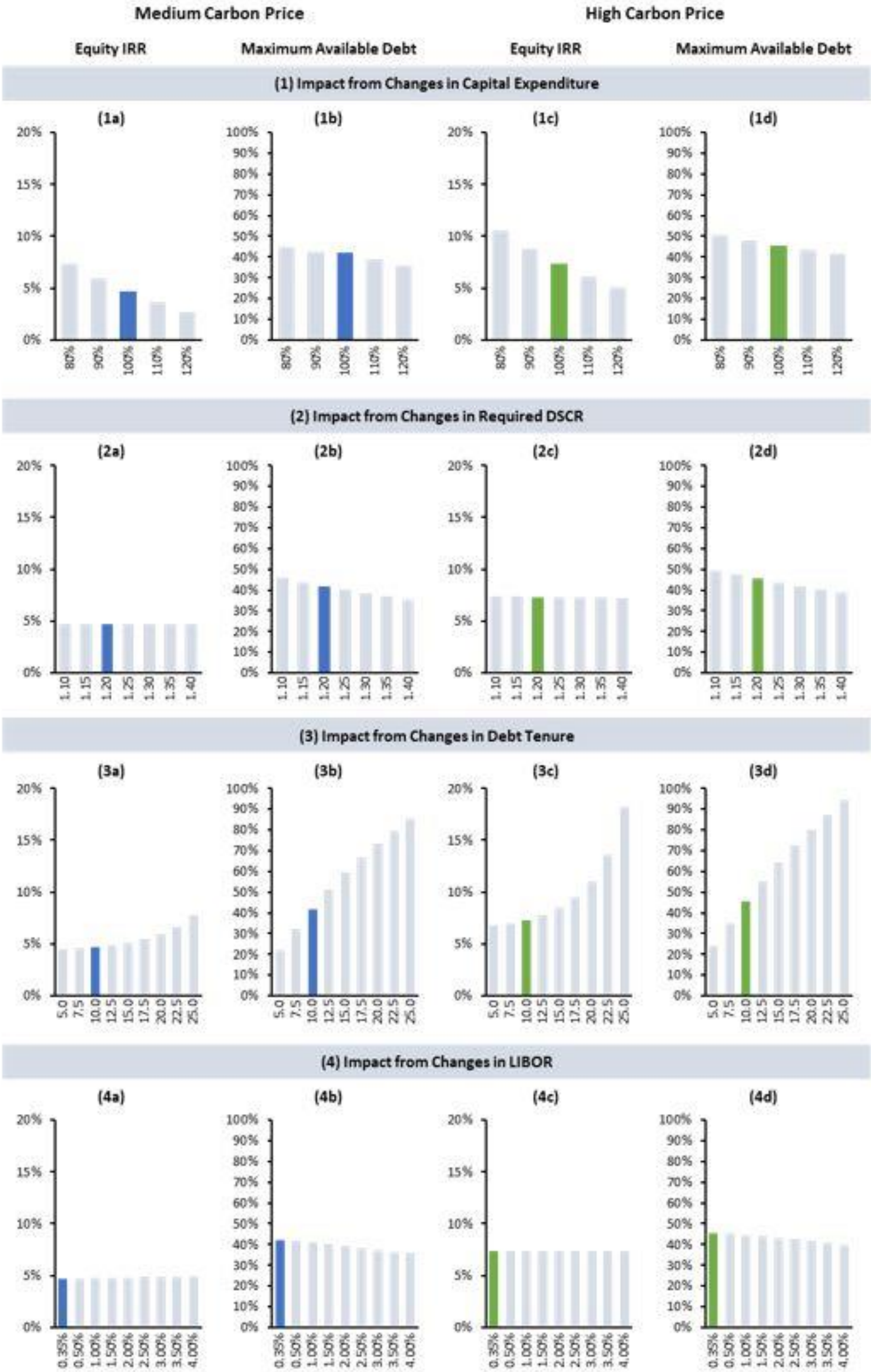


Figure 3: Scenario analysis on project debt and equity returns



Preferential treatment in renewable energy auctions: an analysis of the reference yield model & German wind auctions

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Keywords: renewable energy auctions, reference yield model, German wind auctions, stochastic simulation

Motivation

Procurement auctions are increasingly used to allocate and set the level of support in the form of subsidies for new renewable energy sources. Whether the auction will be successful depends largely on the auction design. There is no one size fits all solution and specific design elements usually come with trade-offs between different goals of regulation and as such a suitable regulatory framework will always depend on the priority of the regulator.

I analyse an auction design that adjusts the competitive conditions for bidders to compensate for differences in their sites' qualities, the reference yield model ("RYM"). Such an auction design is used for onshore wind auctions in Germany.

Relatively underexplored design element which have the potential of changing the behaviour in auctions as well as development of new projects in general. As the RYM compensates projects with different wind conditions differently, it is changing the underlying value of projects going to auctions. Based on the German specific design element I derive a more general approach and address the impact of preferential treatment of projects in Renewable Energy Auctions.

Several studies have been performed to explore the design elements applied in the case of German however none does address cost-efficiency issues while also taking into account the strategic effect of auction theory. E.g., Bichler et al. (2019) analyse German wind auction designs and conclude that the RYM leads to higher average remuneration per kWh.

I test whether and under which circumstances it can influence the outcome of the auctions and what is the effect on auction efficiency. The main research question is thus: does the reference yield model increase or decrease the cost efficiency of renewable energy auctions and what are the main drivers for the effect?

Methods

The model is based on predictions of auction theory calculated using stochastic simulations. Renewable energy auctions are typically conducted as multi-unit first price sealed bid auctions. Two simplifications are assumed; first, uniform pricing (second price) is used instead of discriminatory pricing (first price), although discriminatory pricing is mostly used in practice (as well as in German wind auctions). Uniform pricing can serve as a simple benchmark in the analysis, as only bidder´s costs and potentially correction factor is determinant for the bidding strategy (and both are known within the model). Second, the model does not assume bidders entering with multiple projects within one auction.

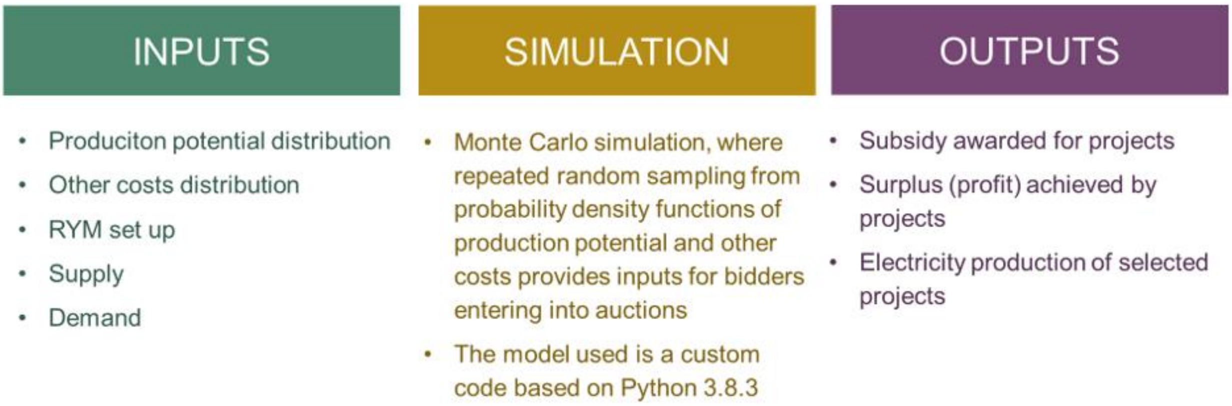
The model thus assumes that bidding one´s cost in a multi-unit auction with uniform pricing, when the bidder submits bid for only one unit, is a weakly dominant strategy (Milgrom, 2004).

All inputs distributions to derive minimum bids are inputs to the model, therefore the model can predict the behavior of bidders based on specified input distributions. As the number of inputs is significant and their distribution may also vary, the computation model is set up as a Monte Carlo Simulation. It calculates various representative scenarios. The output of the calculation is the amount of subsidy awarded, project surplus and achieved production. Simplified scheme is provided in Figure 1.

By calculating combination of different set ups of the input parameters the model shows the difference between scenarios with the RYM with scenarios where the RYM is applied only partially or not at all.

I also show the effect which the RYM may had on the auctions in Germany by inputting specific parameters of supply, demand (both known) and production potential distribution. The production potential distribution is estimated using geographical location of existing wind farms (using data from Open Power System Data) matched with average wind speed (taken from Global wind atlas).

Figure 1



Results

One could intuitively assume that if bad projects are compensated more and thus worse projects with higher costs are chosen in the auctions, then the average level of subsidy in auction should increase. However, considering bidding behaviour, such mechanism significantly decreases the potential for surplus creation for better projects.

Auction theory has provided a theoretical basis for the RYM a long time ago, with the analysis of the price preference policy which is analogically similar to the RYM (McAfee & McMillan, 1989). It showed that price preference policy has a strategic effect that can lead to a lower expected price for the regulator.

Bichler et al. (2019) concludes that the RYM leads to higher average remuneration per kWh, however considering bidding behaviour this does not and in many cases should not be the case. The results show that, in weakly competitive auctions, the reference yield model decreases the bidders' profits and the subsidies. Calibrating the model to data from German onshore wind auctions, I find that, in weakly competitive auctions, the RYM decreases the subsidies up to 22 EUR/MWh. In strongly competitive auctions, it increased the subsidies, but by less than 1 EUR/MWh. As the German wind auctions were mostly undersubscribed and thus weakly competitive, the net effect was decreasing.

It is important to note that if the RYM does not precisely follow the relation of wind conditions to costs and if it overcorrects, it might have substantial adverse effects. It can systematically promote worse projects over good ones and create possible surplus for bad projects.

The effect of the RYM depends on many factors, mainly the shape of the supply curve (production potential of projects), other costs distribution and demand/supply ratio of auctions. In principle the RYM levels the playing field and let the bad compete against the good. It might bring significant decrease of subsidy awarded, but it can also turn the competition upside down.

Keynote 15:45 – 16:30

Room: CHE/S91, hybrid
Chair: Prof. Dr. Dominik Möst

Technical pathways to and economic issues with decarbonizing electricity systems

Prof. Ramteen Sioshansi, PhD [1]

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Abstract

This talk explores two important issues in decarbonizing electricity systems. The first is understanding the potential role of renewable-energy technologies to decarbonize electricity production while maintaining reliable supply and the role of energy storage therein. The second concerns economic and market-design issues that arise from the use of different policy mechanisms to drive decarbonization of the electric power system. To this end, we present and survey the results of capacity-expansion modeling and market-modeling exercises that shed light onto these questions.

Session 16:35 – 17:35
Hydrogen and hydrogen-based commodities

Room: CHE/S91, hybrid
Chair: Philipp Hauser

Opportunities for the German gas grid by using synthetic fuels from an energy system perspective

Felix Kattelmann, IER Stuttgart

Amonia and its role in the European hydrogen market ramp-up

Philipp Hauser, VNG AG

Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities

Michael Moritz, Uniper

Opportunities for the German gas grid by using synthetic fuels from an energy system perspective

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Keywords: gas grid, infrastructures, energy system model, synthetic fuels, sector integration

Motivation

The ambitious plan to make Germany climate neutral by 2045 requires a radical structural transformation of the energy system. This not only necessitates a change in generation, but also a fundamental transformation of the underlying infrastructures of the energy system; almost all grids will have to be newly built, expanded, converted or deconstructed. The ambitious Greenhouse gas targets creates an enormous pressure on the gas grid, the total fossil gas consumption could decrease massively, which could necessitate gas grid dismantling. From an economic and systemic perspective, however, the gas grid is a valuable asset that has been built at great capital cost. Given the system transformation, it is beyond all question that new infrastructures will be a necessary part of the new energy system, but consideration to whether it is possible to keep using this existing infrastructure is imperative. The owners of the gas grid hope for continued operation of their valuable asset, either by a switch from natural gas to synthetic methane or by the conversion of their gas grids into hydrogen grids. This rededication would require considerable investment, while dismantling would also be capital-intensive and time-consuming. In view of the phase out of nuclear power and coal-fired electricity generation or the ban on new oil-fired heaters in buildings, it may even be economically attractive to invest in the expansion of gas grids due to the possible medium-term increase in gas consumption. Grid operators need clarity about the possible orientation of the gas grids so that first investment decisions can be made in the next few years. This work aims to contribute to this discussion by answering the issue from an energy system perspective: Are there opportunities for the German gas grid by using synthetic fuels in the future? The focus is on CO2 neutral fuels, but in light of war in Ukraine the possible option of persistently high prices for fossil gas will also be considered.

Methods

In order to analyse the infrastructures integrally within the context of the entire energy system, an adequate mapping of infrastructures into the energy system model TIMES PanEU takes place.

With this integrated model approach, interactions of the gas grid with other infrastructures can be taken into account. On the other hand, a conjoined analysis of the gas grid with the supply and demand for energy carriers (e.g. natural gas), which represent endogenously calculated parameters of the model, can be carried out. Consequently, this approach allows for dedicated grid analyses in the context of the transformation of the energy system.

TIMES PanEU is an energy system model and contains a depiction of Germany's entire energy system. Exogenous demands for energy services (e.g. space heating) are given and a variety of technologies are provided that can either meet the demands directly or indirectly via upstream conversion steps.

To enable the analysis of infrastructures, three grids (Electricity, Gas and Hydrogen) that are deemed crucial for the energy transition are newly implemented in the model additionally to the already existing district heating grid. All infrastructures are assigned costs for maintenance, expansion, possible deconstruction or conversion. The model then endogenously determines which capacities of the infrastructures are required for providing the demand for e.g. natural gas. For the analyses, different scenarios are calculated, having climate neutrality as a requirement and differing in the prices for the supply of hydrogen, natural gas and synthetic methane to find out whether low-cost synthetic fuels can replace today's fossil gas consumption and what influence high-cost fossil gas has on the system. Based on this, the necessary future gas grid capacities are subsequently estimated by the model. The fundamental topic of this work is whether there is a scenario in which the gas grid or certain parts of it can continue to be operated economically.

Results

As our analyses show, climate neutrality exerts enormous pressure on the gas grid, which results in sharply reduced gas consumption and an accompanying severe dismantling of the transmission and distribution grids to about 30%. However, low-priced synthetic energy sources lead to prospects for the continued use of the gas grid assets. A comparatively low price for syngas of 60 €/MWh enables the partial (about 50%) continued operation of both layers of the gas grid.

Low-cost hydrogen with a price of 59.4 €/MWh offers to keep more than 2/3 of the gas transmission grid in operation. However, the double-edged effect of hydrogen becomes apparent in this case, as the distribution grids cannot be maintained on a large scale with hydrogen, but have to be drastically dismantled. This effect is mainly due to the decline of gaseous energy carriers in the building sector. While with low-cost syngas in 2045 up to a third of the fossil gas consumption in 2020 can still be achieved by using syngas, low-price hydrogen only comes to about 1/10, resulting in a massive dismantling of the distribution grids. From an energy system perspective, the economically more attractive sector integration option in buildings is direct electrification, resulting in a decline of gaseous fuels.

High-price fossil gas accelerates this trend even more, with a permanent price of 71 €/MWh, the decline in gas consumption accelerates significantly, leading to 30% of the initial value being reached by 2030.

Nevertheless, all scenarios show that the present level of gas grid utilization will never be attained; even with highly optimistic price assumptions, there will always be a more or less substantial dismantling of the gas grid required, and the distribution grids in particular will be severely affected by this fundamental impact. From an energy system perspective, the dismantling of the gas grids, regardless of the specific scale, is an unavoidable trend due to the goal of climate neutrality.

Amonia and its role in the European hydrogen market ramp-up

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Keywords: ammonia, hydrogen import, hydrogen derivate, energy transport infrastructure

Motivation

Ammonia is expected to play a major role in the hydrogen market ramp-up in two ways: as a carbon-neutral feedstock and as a hydrogen carrier. The ongoing energy transition focuses in the next decade on decarbonizing the industry and transport sector. Against this backdrop, the German hydrogen council (Nationaler Wasserstoffrat) expects a German hydrogen demand of 90 up to 110 TWh in 2030. This demand has to be covered by domestic production and imports. While the expansion of wind an PV plants is a core action in Germany, another political objective aims to install a capacity of more than 10 GW electrolysis until 2030. Assuming 4,000 full load hours and an efficiency of 70%, the domestic green hydrogen supply will amount about 28 TWh/a. The gap to meet the expected demand amounts round about 60 to 80 TWh/a that has to be filled with non-green domestic hydrogen production, e.g., steam methane reforming with carbon capture and storage (blue hydrogen) or without CCS, that is the today's dominant hydrogen production method (grey hydrogen). The second supply alternative is importing hydrogen or hydrogen derivates such as ammonia.

There is a bundle of reasons why ammonia is likely to become important in the market ramp-up phase for hydrogen. While first approaches have discussed ammonia only as an import option, latest discussions focus on the entire ammonia value chain and its applications to replace fossil fuels in end energy demand sectors. There might be technical and economic advantages to use ammonia also as an energy carrier in the power and transport sector. However, an increase in ammonia applications pose the question of what would be the implications for the planned hydrogen infrastructure?

For this reason, this paper discusses the pros and cons of including ammonia in the hydrogen value chain from a techno-economic perspective and provides recommendations and ideas for further research in the field of energy system analysis.

Methods

The discussion is based on a wide collection of literature that reflects ammonia from both perspectives: as an energy carrier and as a transport carrier. First, the current and possible future applications of ammonia are presented. Second, based on different roles of ammonia in the decarbonized energy system, implications for infrastructures are discussed. The following indicators are used for assessing the different ammonia roles: process efficiency of the respective value chain, benefits and costs, aspects of system integration and interdependence to alternative transport infrastructure, life cycle assessment with special regard to CO2-emissions.

Results

It is expected that the structured analysis provides insights on the sustainable role of ammonia as a hydrogen carrier and for applications in the power, industry, and transport sector. Drivers and barriers are identified that may help investors to avoid sunk investments and policy makers to find appropriate supporting schemes.

This research is part of the BMBF hydrogen flagship project TransHyDE that aims to develop a hydrogen transport infrastructure (Reference number: 03HY201V).

Estimating global production and supply costs for green hydrogen and hydrogen-based green energy commodities

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Keywords: green hydrogen, green ammonia, hydrogen derivates, techno-economic analysis, transport cost, production cost

Motivation

Many countries decarbonise their energy systems by using renewable energies to mitigate climate change and achieve a sustainable energy supply. Renewable energy sources (RES), in particular wind and solar energy, can be used to produce green electricity. In addition to green electricity, hydrogen and hydrogen-based green energy commodities are projected to play a significant role in the decarbonisation of so-called hard-to-abate sectors, where direct electrification is difficult. Applications for synthetic green energy commodities could be long-term energy storage, feedstock for industrial processes and use as fuel in heavy duty transport or aviation.

Production potentials for green energy commodities are distributed unevenly around the globe. Countries with a high energy demand do not necessarily have access to large RES potentials. Germany, for example, would have to continue to rely on energy imports as part of a cost-effective decarbonisation strategy. Even in the long term, Germany will probably have to cover up to half of its energy demand using molecule-based energy carriers. A considerable part of these molecule-based energy carriers might be synthetic green energy commodities due to limited sustainable biomass potentials. Green hydrogen plays a central role. Hydrogen can be used energetically or as a feedstock for hydrogen-based commodities such as ammonia, methane, methanol or Fischer-Tropsch fuels like synthetic kerosene, gasoline or diesel.

We quantify the production cost and potentials of hydrogen and the hydrogen-based energy commodities ammonia, methane, methanol, gasoline, diesel and kerosene in 113 countries. Moreover, we evaluate total supply costs to Germany, considering both pipeline-based and maritime transport.

Methods

The methodology is based on Brändle et al 2020 (Estimating long-term global supply costs for low-carbon hydrogen, Applied Energy) that developed an optimisation tool for global hydrogen production costs.

We expand the model to optimise the production of four synthetic hydrogen-based energy commodities: ammonia, methanol, methane and Fischer-Tropsch liquids. In addition to a RES and an electrolyser (like in Brändle et al), the model now incorporates hydrogen storage, and the respective commodities' synthesis process. Furthermore, we extend the dataset built by Brändle et al. [13] to 113 countries and introduce country-specific weighted average costs of capital estimates to analyse the impact of differences in financing costs and country risk on the respective green energy commodities' levelised production cost. Our full set of results is available for download in a spreadsheet tool (https://www.ewi.uni-koeln.de/de/publikationen/globales-ptx-produktions-und-importkostentool/).

Results

We find that while pure hydrogen has the lowest production costs, its transportation costs are the highest, especially when it comes to maritime transport. Thus, hydrogen is likely to be traded mostly regionally by pipeline, for instance within Europe and North Africa. In the supply cost structure of synthetic, hydrogen-based ammonia, methanol and methane, by contrast, production costs are the dominant cost component and transport costs are smaller. This would potentially allow for the emergence of global maritime trade in these commodities. In the case of green ammonia supplied to Germany, the direct import of green ammonia by ship is cost-efficient compared to domestic production of ammonia from domestically produced or imported hydrogen. Only if a European hydrogen pipeline grid based on repurposed natural gas pipelines exists could ammonia production from imported hydrogen in Germany potentially be cost-effective.

Session 16:35 – 17:35
Renewables in developing countries

Room: CHE/S89, hybrid
Chair: Constantin Dierstein

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Winners of the best Diploma / Master's thesis award

Alexander Michael Floren and Malte Karitzky

Extension of Flow Based Market Coupling to the Core Region - An Analysis

Alexander Michael Floren

Tenant-generated electricity in Germany - An empirical study to identify and evaluate administrative hurdles in the implementation of photovoltaic projects

Malte Karitzky

South Africa's energy transition – Unravelling its political economy

Jonathan Hanto, Europa-Universität Flensburg, TU Berlin

How population migration affects carbon emissions in China: Factual and counterfactual scenario analysis

Yan Bu, Dalian University of Technology

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Extension of Flow Based Market Coupling to the Core Region - An Analysis

Alexander Michael Floren

Keywords: Flow based market coupling, available transmission capacity, core region, CWE region, model-based analysis

Motivation

This work deals with the planned expansion of the FBMC from the CWE to the Core region in Europe. The aim of this thesis is to gain initial insights into the effects of this expansion, whereby the results can serve as a starting point for further studies.

Methods

The investigations in this thesis are based on a model-based analysis. The model represents both the day-ahead market clearing and the subsequently necessary redispatch measures, whereby the 13 countries of the core region form the system boundary. The model is mainly based on a data set for the European electricity market in 2014. In order to obtain simulated results for one year, 25 representative reference hours were developed using the K-Means cluster algorithm. The analyses focus on the comparison of the two scenarios "CWE FBMC" and "Core FBMC". In the former, the FBMC is only applied in the CWE region, with trade with and among CEE countries using the ATC method. The second scenario simulates the full application of the FBMC in the Core region.

Results

Basically, an overall increase in welfare and efficiency of the Core FBMC compared to the CWE FBMC can be observed, with the former being estimated at around 201 million euros for the Core region. Here, the Core FBMC shows increased generation costs of market clearing compared to the CWE FBMC, but significantly decreasing grid congestion of around 31 percent. These lower grid overloads result in considerable cost reductions in redispatch. While the extension of the FBMC to France, Belgium and the Netherlands has only minimal effects, significant changes are evident in Germany, Austria and the CEE region. Germany significantly reduces its positive trade balance, while Austria becomes a net exporter. It becomes clear that by expanding the FBMC, the effects of trade flows on real physical load flows can be better mapped to a considerable extent. Furthermore, it is only through the Core FBMC that particularly relevant lines are identified as critical network elements in the FBMC algorithm, namely lines in the eastern part of the CWE region. The work concludes that the particularly critical network for the core market algorithm is in Germany and Austria and that the optimisation of trade flows is largely determined by the limitations there. This results in a considerable number of non-intuitive situations, especially in the CEE countries. In the Core FBMC, the simplifications of the FBMC also lead in part to incorrect estimations of the load flows, for example through internal trading.

enerWARD 2022
Winner of the best Diploma / Master's thesis award

Tenant-generated electricity in Germany - An empirical study to identify and evaluate administrative hurdles in the implementation of photovoltaic projects

Malte Karitzky

Keywords: Photovoltaics, tenant electricity, neighborhood solutions, hurdles and barriers, empirical evaluation

Motivation

This diploma thesis takes a closer look at the topic of tenant electricity. The development of the expansion of plants to date and their geographical distribution are classified in potential estimates. The focus is on the identification of existing stakeholders and the barriers and obstacles that are holding back an accelerated expansion of photovoltaic plants.

Methods

Key metrics on the existing tenant power expansion are evaluated and barriers are collected and structured. These are then evaluated as part of an empirical study to identify problem areas and derive possible solutions.

Results

The evaluations attest to particularly high barriers in the area of administrative effort. In addition, the framework conditions in the Tenant Electricity Act severely restrict implementation and the technical effort leads to high initial costs. On average, the participants in the survey achieve a return of 3.46% p.a. and demand 6.04% p.a. when implementing their projects. The burden on stakeholders cannot be characterized by a few influential barriers, but by the interaction of a multitude of barriers. Accordingly, no simple solutions can be defined to mitigate a multitude of barriers. However, the focus should be on increasing the subsidy through the tenant electricity surcharge and reducing administrative barriers through adjustments to the Tenant Electricity Act. Furthermore, there is a lack of marketing and information sources that facilitate entry into the tenant electricity field for non-specialists.

South Africa's energy transition – Unravelling its political economy

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Keywords: South Africa, coal, political economy, renewable energy, just transition

Motivation

The concept of a low-carbon transition is increasingly gaining traction in South Africa. This constitutes a major technical, social and political challenge as South Africa's energy sector is still shaped by the country's apartheid history and by post-apartheids political, social, and economic forces. Given South Africa's high coal endowment, the resource has been a critical part of South Africa's economy for decades.

In 2019, coal accounted for about 75 % of total primary energy supply and 88 % of electricity generation. Coal mining contributes 2.3 % to South Africa's GDP with 40 % to 45 % of the sales income attributable to the export market, namely to India, Pakistan and South-East Asia.

The energy sector is responsible for 80 % of South Africa's greenhouse gas (GHG) emissions. Thus, a transition away from coal is key for the country to achieve its Nationally Determined Contributions (NDCs) in line with the ratified Paris Agreement, its domestic policy targets and national development goals, and to reduce negative externalities from coal mining and coal power plants such as pollution and negative health effects.

The country has a high unemployment rate of over 40 % and vast economic inequality represented by a Gini-Coefficient of 0.63, now exacerbated by the Covid-19 pandemic. As a result, the concept of a just transition that acknowledges socio-economic and environmental aspects is regarded as a crucial component for a successful low-carbon transition, including coal phase-out. This case study aims at contributing to understand the guiding forces that influence and are influenced by the coal- and energy sectors in South Africa. The analysis will help to expand the understanding on how and why coal has been dominating the national energy sector and why a respective phase out has been developing rather slowly. The insights from the analysis are used to reveal key challenges and opportunities regarding an energy transition and to derive policy implications.

Methods

For this case study an in-depth, theory guided analysis of the political economy of electricity in South Africa was carried out, applying a theoretic Political Economy Framework. Drawing on semi-structured expert interviews, the aim is to identify the main actors, their main objectives and contextual factors shaping energy and coal sector related decision-making processes. In total, 5 political actors, 8 societal actors and 8 business actors were interviewed.

The interview guideline is separated into four main parts, asking the the interviewee about (1) current challenges, (2) the most relevant policies in South Africa's energy sector, (3) the process of policy formulation, and (4) relevant contextual factors. The guideline enables the completion of multiple interviews with a similar structure to ensure comparability, while also giving the interviewer the liberty of addressing the interviewees' area of expertise and related topics. Subsequently, a qualitative content analysis was conducted. In a first step, notes from the interviews, information from literature and the political economy framework were used to identify patterns and concepts in order to define a first set of objectives, related actors, and contextual factors. Following, a coding process was used to identify themes across interview data through an iterative process of reading and re-reading the transcriptions and therefore elaborating on initial codes, to make finer distinctions within each of the coding categories or collapse them into broader categories.

This process yielded four overarching coding categories (main objectives) with multiple sub-objectives each. While contextual factors usually directly relate to one of the four objectives, they were also coded into three different sets (Techno-Economic, Institutional, Discursive) of their own to create a helpful representation of the context surrounding South Africa's energy and coal sector.

Results

Through a qualitative analysis of 20 interviews in conjunction with a literature review, the important actors, objectives and context factors for the South African energy and mining sectors were determined. Four main objectives influencing the national energy sector could be derived: First, “Energy availability” is an objective mentioned throughout the interviews as South Africa still needs to find solutions to an immediate supply gap, rising electricity prices and access to energy. Addressing the issue of energy security and ongoing load-shedding is in the focus, as new procurement programmes aim to increase capacity in the short- and medium term.

The second objective “Maintaining profitability of the coal sector” is driven by economic, political and societal actors. Interviewees indicated coal-related (export) revenues and much needed employment that supports local communities to be essential factors in the prevalence of coal.

Third, "Environmental and climate protection" was recognised as an objective important to societal and political actors. Actors highlight the need for an effective national strategy for GHG reduction and a more competitive and investor-friendly regulatory environment for renewables. Lastly, "Reducing inequalities and employment insecurity" is a key objective acknowledged by all interviewees. It ties into the concept of a just energy transition that takes into account the multitude of socio-economic impacts. The challenge of finding employment alternatives for people currently employed in coal mining and the coal value-chain is regarded as essential to minimise detrimental effects on communities.

In South Africa, climate change mitigation goals and solutions cannot exclusively be considered in the context of low-carbon and energy efficiency. Rather, they are tied to broader socio-economic implications. Therefore, they need to be embedded into a just transition framework.

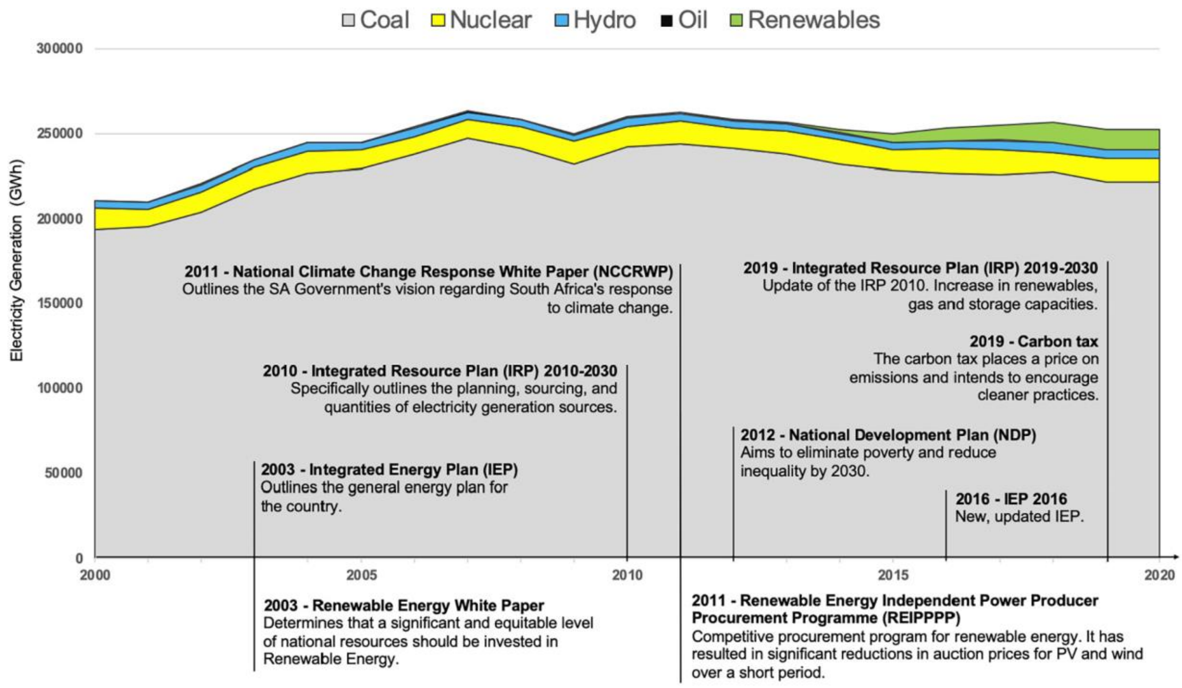

Figure 1

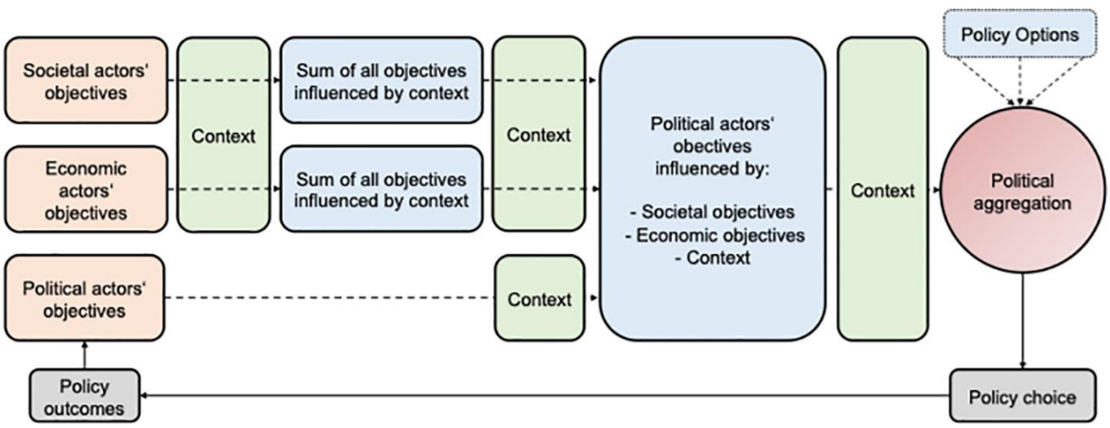

Figure 2

Contextual Factors

Techno-Economic
Electricity supply crisis with an immediate capacity gap
Old coal power plant fleet with low Energy Availability Factor (EAF)
Unfavourable market environment for new coal investments
High RE potential and decreasing costs
High share of international IPPs in RES sector
Electricity public utility Eskom (accounting for over 90% of ZA power generation) in operational and financial crisis

Institutional
Strong vested interests by multiple groups related to the minerals-energy complex
Energy and mining integrated in the same government department
Political disputes about ownership in power sector persist and limit uptake of RE via mainly privately owned, foreign IPPs
Strong societal influence by workers unions affiliated with the coal sector
No overarching plan that includes all aspects of government, business and society

Discursive
Negative health and environmental effects of coal mining
High employment numbers related to coal cause for opposition of renewables to maintain status quo
High unemployment and societal inequality
Civil society challenges new coal and nuclear projects in courts
Uncertainty among investors due to delays in policy implementation
Negative socio-economic impact of the Covid-19 pandemic
Dependence on coal-exports makes South Africa vulnerable to fluctuations in the global coal market

Objectives

Energy availability
Security of supply
Affordable electricity
Electricity access

Maintaining profitability of the coal sector
Revenue from coal
Rent-seeking and vested interests
Employment and regional development

Environmental and climate protection
Climate change mitigation
Procurement of renewables (RES)
Reducing negative effects from coal

Reducing inequality and employment insecurity
Creating employment alternatives
Ownership
Stakeholder engagement

Actors

Political
President
Political parties (ANC, DA)
National government
Government departments
Municipalities
Provincial government
Local government

Societal (incl. business)
Civil society
National/international NGOs
Think tanks
Universities
Trade unions
Coal industry
Mining companies
SOEs (Eskom, Sasol)
Renewable energy industry
Representatives of businesses
Banks
International investors
Independent Power Producers (IPPs)

Figure 3

How population migration affects carbon emissions in China: Factual and counterfactual scenario analysis

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Keywords: population migration, carbon emissions, geographically weighted regression, multi-regional input-output analysis, China

Motivation

China's large-scale inter-provincial population migration has a vast impact on social changes, and significantly altered the energy consumption demand of various provinces, and further affected the spatial distribution of carbon emissions. Nevertheless, less attention has been paid to the impact of population migration on carbon emissions.

Methods

To make up for the niche, this paper develops an innovative framework by integrating a geographically weighted regression model, a population migration matrix, and an environmentally extended multi-regional input-output model to assess the impact quantitatively based on factual and counterfactual scenarios.

Results

The results show that the carbon emissions increased by 78.16 million tonnes (Mt) in 2017 due to population migration, of which direct carbon emissions increased by 6.91 Mt and indirect carbon emissions increased by 71.25 Mt. It must be emphasized that population migration increases indirect carbon emissions driven by urban consumption and investment in the provinces with net in-migrants. But these provinces transfer more carbon emissions to the regions with net out-migrants, which implies that population migration exacerbates carbon emissions inequality. This especially increases the carbon emission reduction barrier of provinces with net out-migrants. Overall, these empirical discoveries shed light on making regionally coordinated carbon reduction policies.

Session 16:35 – 17:35
Sector integration of heating and cooling appliances

Room: CHE/183
Chair: Carl Philipp Anke

Optimisation of costs, carbon emissions and thermal comfort in a building-level energy system model

David Huckebrink, Ruhr-University Bochum

Sector integration with residential heat pumps: the impact of building characteristics and user behaviour

Evelyn Sperber, Deutsches Zentrum für Luft- und Raumfahrt e. V.

Load shifting of distributed cross-sectoral energy systems in economically optimised operation

Sebastian Berg, Fraunhofer UMSICHT

Optimisation of costs, carbon emissions and thermal comfort in a building-level energy system model

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Keywords: multi-objective optimisation, energy system modelling, residential heating, sector coupling, thermal comfort

Motivation

To mitigate the effects of climate change, it is necessary to decarbonise the energy system as a whole. Countries worldwide committed to greenhouse gas (GHG) emission reduction targets, for which a switch from fossil fuels to renewable energy sources is needed. This energy transition comes with great technical and social challenges and leads to highly complex decision-making situations. To support decision makers, energy system models (ESMs) are used to describe and optimise the design and operation of energy systems.

While many efforts focus on the power sector, other energy sectors are often neglected. However, decarbonising the energy system holistically is crucial for meeting emission reduction targets and including multiple energy carriers in ESMs also provides valuable synergies. For instance, buildings can act as thermal energy storages and provide flexibility to the electricity sector. Human behaviour has received even less attention than the heating sector [1], although a recent IPCC report deems it a highly relevant topic to meet global climate targets. In particular, individual behaviour in the residential heating sector drives energy demands, carbon emissions and the flexibility potential described above.

In this work, we therefore provide a coupled ESM of the power and residential heating sectors that includes an endogenous measure for thermal comfort, and thus a behavioural aspect, as an objective function. To reflect interests more realistically, we consider system costs and GHG emissions as two additional objectives. The simultaneous optimisation of all three objectives results in a Pareto front and allows to study and quantify trade-offs between the potentially conflicting objectives. Thereby, we address a third shortcoming of many ESMs that take a single-objective cost-minimising approach and thus only result in a single solution.

Methods

The methodology has three main pillars: (i) a building model that endogenises temperature as a decision variable in the open energy system modelling framework Backbone [2]; (ii) an empirically founded method that allows to proxy thermal comfort as a function of room temperature; (iii) an implementation of a multi-objective optimisation method in Backbone.

The building model [3] consists of three nodes representing the building's structural components, the interior and the building's floor. Each node is given a heat capacity for conversion of the nodes state between energy and temperature. Connections between these nodes are implemented using U-values and areas of the respective components, allowing for heat transfer between them based on their temperature differences. Thus, the model can control the temperature at the interior node through scheduling of heat pumps or gas boilers.

The endogenisation of temperature in the model allows to assess thermal comfort by using the percentage of people dissatisfied (PPD). This empirically founded method, prevalent in the scientific literature and national standards, measures satisfaction with thermal indoor conditions. Since the PPD is an exponential function, we approximate the PPD by a linear function of the deviation from a set temperature to be integrated in the multi-objective optimisation.

The implementation of the augmented epsilon-constraint method (AUGMECON) in Backbone [4] calculates a set of Pareto-optimal solutions for the building model. The method is highly flexible in terms of sectors, technologies and system size as well as number and type of objectives. Here, it is used to minimise system costs, GHG emissions and the function for thermal discomfort that sums up the PPD of all modelled hours.

Results

In a first step, the model of an individual building is used as is and the resulting Pareto front is shown in Fig. 1 from different perspectives in 3-dimensional solution space. Different conflicts between the three objectives of minimising costs, discomfort and emissions can be observed. First, there is a clear trade-off between costs and emissions that is influenced by the emission level, but mostly independent of the level of comfort. Marginal emission abatement costs increase with decreasing emissions. Second, higher thermal comfort increases costs significantly only at emission below 0.5 t. For emissions above this threshold, comfort can be increased at almost no additional cost. Finally, there appears to be no conflict or even correlation between comfort and emissions, i.e. at each comfort level, any level of emissions can be achieved and vice versa. This is, because the sources of renewable energy are only limited by financial resources in this simple model.

In a second step, the building model will be enhanced, and the comfort function will be improved. To do so, additional nodes for buffer and domestic hot water storage and radiators will be added to the building model for a more realistic depiction of residential heat provision. The improved comfort function will use a piece-wise linear approximation of the PPD including different clothing levels, which affects the PPD across a broad range of temperatures. In the final step, publicly available data on the European building stock [5], heat demand [6] as well as electricity generation and transmission [7] will be used to build a larger scale aggregated energy system model including a flexible residential heating sector. This will eventually provide a multi-objective sector-integrated optimisation model of the energy transition, including the often overlooked heat transition and behavioural aspects.

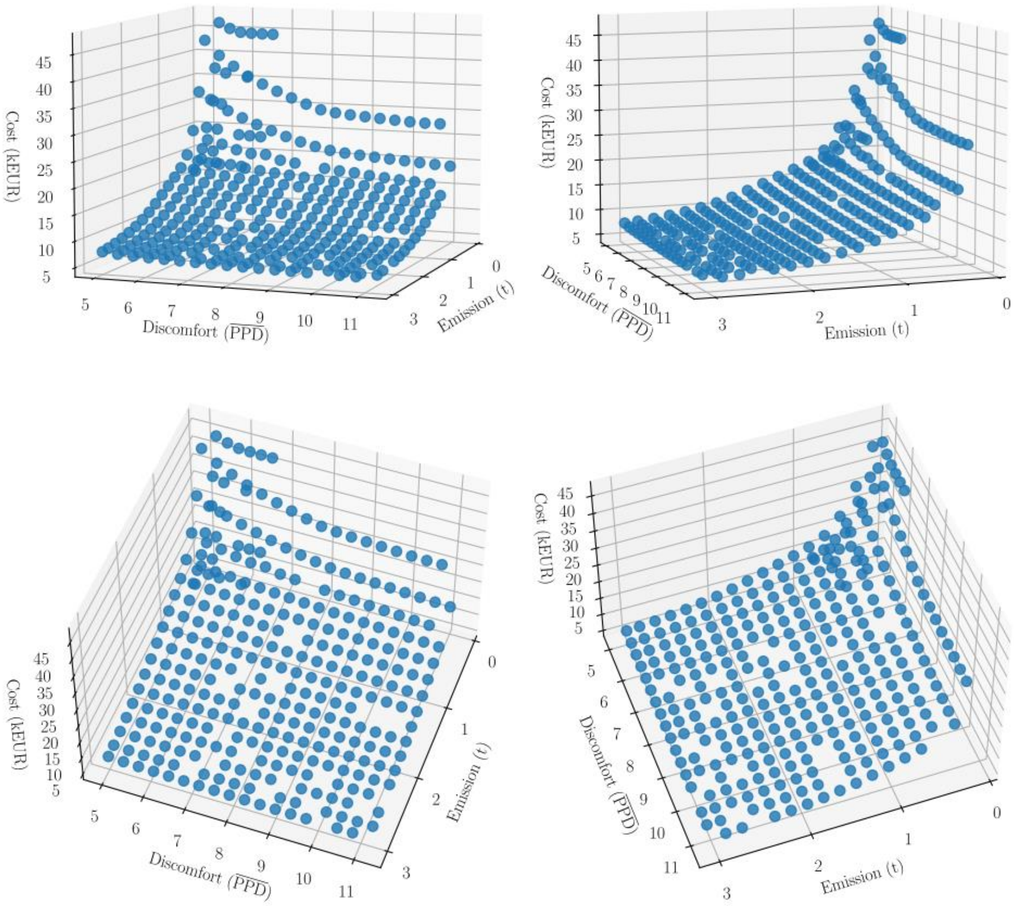

Figure 1

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Sector integration with residential heat pumps: the impact of building characteristics and user behaviour

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Keywords: heat pumps, demand response, building thermodynamics, agent based simulation, optimization

Motivation

The current energy crisis requires a rapid transformation of the building heating sector. According to plans of the German government, heat pumps are to play a decisive role in this: from 2024 onwards, at least 500,000 new heat pumps are to be installed in Germany every year [1].

As a technology at the nexus of the power and heat sector, the system-wide requirements and impacts of a large heat pump expansion need to be carefully assessed. On the one hand, this relates to the challenges, but also chances that heat pumps pose for the electricity system. On the other hand, the prerequisites on the building side for efficient operation of heat pumps need to be taken into account. This is particularly relevant if heat pumps are to be used as a demand response (DR) option for balancing supply and demand in the energy system of the future.

A number of studies address the system-wide impacts and interactions of heat pumps, taking into account their DR potential. However, in most studies the building side is insufficiently considered. In particular, there are knowledge gaps regarding the role of characteristics of the buildings in which heat pumps are used, such as the thermal efficiency level and the heating distribution system. In addition, the influence of user behavior has so far been poorly assessed. In this context, a high DR potential can be exploited by users temporarily rising or lowering the temperature in the building, making use of passive heat storage inside the structural thermal mass [2].

This study contributes to filling existing research gaps in the assessment of sector integration with residential heat pumps. The following questions will be answered:

- What effects do residential heat pumps have on the electricity market – with and without exploiting their DR potential?
- What is the influence of building characteristics and of user behavior regarding comfort temperature settings?

Methods

To answer the research questions, an innovative integrated model is developed that adequately considers both the building side and the electricity market. It consists of an optimization model for residential heat pump dispatch linked to a reduced-order model of building thermodynamics that is integrated into the agent-based simulation model of the German electricity wholesale market AMIRIS [3,4].

Within AMIRIS, the main actors of the electricity market (power plant operators, traders, storage facilities, etc.) are modeled as agents (see Figure 1). These agents make independent decisions based on the information they acquire in order to pursue their own interests (e.g., profit). From a modeling perspective, each of these agents can be assigned individual decision algorithms, ranging from simple if-then decisions to optimization algorithms to artificial intelligence.

In AMIRIS, a heat pump aggregator agent is introduced as an intermediary between the wholesale market and residential heat pumps. The aggregator calculates the heat pumps' electricity demand by means of a reduced-order model of building thermodynamics. This internal model features a simplified physical description of building archetypes and computes the electricity demand depending on weather, building and heat pump characteristics as well as comfort temperature levels [2].

Heat pumps can be used as a price-based DR option in the model. By considering real time electricity tariffs provided by the aggregator, the operation of heat pumps shall be shifted away from price peaks to phases of low electricity prices. To this end, an integrated GAMS optimization model computes the cost-minimal heat pump dispatch from a microeconomic perspective. Special attention is paid to passive heat storage in the structural thermal mass of buildings, which is limited by the comfort temperature settings by the users.

Results

While the integrated model development is ongoing and planned to be operational before Enerday 2022, results are already available for a simplified model set-up that considers one building archetype per scenario run (instead of 36 buildings as foreseen in the finished model). The simulations show that heat pumps add to peaks in the residual load, and thus to the demand of backup capacity in the power system. This is especially true if heat pumps are employed in old buildings with poor insulation levels. Dynamic electricity tariffs, which trigger a flexible operation of heat pumps, reveal the benefit of DR: residual load peaks are reduced, but only if buildings provide a high storage mass. The latter is especially the case for modern buildings with underfloor heating. When operated under dynamic tariffs in such modern buildings, heat pumps can also integrate wind power generation that would otherwise have been curtailed. The effects are stronger the higher the accepted temperature variation in the building by the users.

The model further allows to calculate cost and savings for heat pump operators dependent on the electricity tariff. Thus, it is also possible to evaluate tariffs not only in terms of their benefit for the system, but also from a micro-economic perspective.

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Load shifting of distributed cross-sectoral energy systems in economically optimised operation

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Keywords: distributed cross-sectoral energy system, load shifting, flexibility, optimisation, electricity price

Motivation

Flexible operation of distributed cross-sectoral energy systems (DCES) can help to cover residual load. Consequently, it can replace flexible conventional power plants and thus reduce CO2-emissions. As a further benefit, flexible operation is economically profitable.

Still, flexibility potential remains unused in the majority of facilities, even though units that could be used for flexible operation, namely DCES, already exist.

This study aims to outline the flexibility potential and the necessary investments in DCES, as they are crucial for the electricity transition in the German energy system. In order to support the integration of volatile renewable suppliers and replacing flexible conventional power plants, DCES can deliver flexibility for the electricity sector, while being cost-efficient with low CO2-emissions.

DCES are local energy systems including and combining energy conversion plants such as combined heat and power systems (CHP), heat pumps, compression or sorption chiller and thermal energy storage (TES). They are already deployed in many buildings, districts and manufacturing industries with increased energy demand. Within a typical DCES, a CHP produces electricity and heat, a chiller converts these into cooling energy, and a storage can decouple the electricity, heating and cooling generation. Up to now, most DCES are primarily designed to cover the energy demand of their facilities, while flexibility provision is irrelevant.

To utilise the DCES' flexibility potential, the operators need to receive economic benefits as compensation for their effort. As the volatile electricity spot market displays the need for flexibility implicitly, it determines the flexible operation. In times of high residual loads, the price of electricity is also high, which is an incentive for the operator to feed-in electricity. By acting on the electricity market in real time and running a DCES in flexible operation, the operator can gain an economic benefit.

Methods

To analyse flexible DCES operation, we develop mixed integer linear programming (MILP) models for DCES and use measured demand data (electricity, heating and cooling). By using the electricity price, a mathematical solver calculates the economically optimised operation of the units. We analyse these results of the optimised load profiles and display the flexibility of the DCES by comparing it with a reference concept.

Furthermore, we investigate the flexible operation and economic effects by using different electricity price scenarios. To compare the calculations with the status quo, a fixed-price scenario is used. Furthermore, we develop dynamic pricing scenarios. For this, on the one hand, we use the current spot market price and on the other hand, future price forecasts that have a higher volatility compared to the current ones. The optimisation of the model operation regarding dynamic pricing provides additional flexibility.

In a case study, we analyse a DCES of a specific hospital in Hattingen, Germany. Up until now, the implemented energy units run in a non-flexible operation mode. We simulate the flexible operation and analyse the influence of the electricity price scenarios as well as the effect of different units' sizing concepts.

Results

The results show load shifting of the CHP in flexible operation compared to reference operation. While CHP electricity generation in the non-flexible concept is only dependent from heat demand, a heat storage allows shifting electricity generation towards high price periods in the morning and the evening. Within these high price periods, the CHP charges the heat storage and during low price periods, the CHP switches off, and the heat storage covers the heat demand. Depending on the energy demand and the design of the DCES units, differences in natural gas and electricity purchases as well as electricity feed-in can be seen. Explicitly, the size of the CHP has a significant impact on the quantity of the energy flows. Only a CHP with a nominal load bigger than the electricity base load of the hospital enables feed-in potential and therefore electricity sales to the market. These results occur particularly when using a dynamic pricing scenario. The savings increase compared to a fixed-price scenario. A more volatile electricity price allows even more savings.

Hence, the economic optimised flexible operation of the hospitals' DCES in Hattingen provides flexibility to the electricity market, while the operator saves money even without having to install new costly energy units. The already existing units only need to be modified for smart connection between each other and to the market. The expenses to digitise the DCES are relatively low and should be an objective for the future anyway. Thus, the investment costs for the provision of flexible operation are low.

This study shows economic and ecological optimization potentials in the operation of already existing distributed cross-sectoral energy systems. The presented method can be applied easily for other DCES.

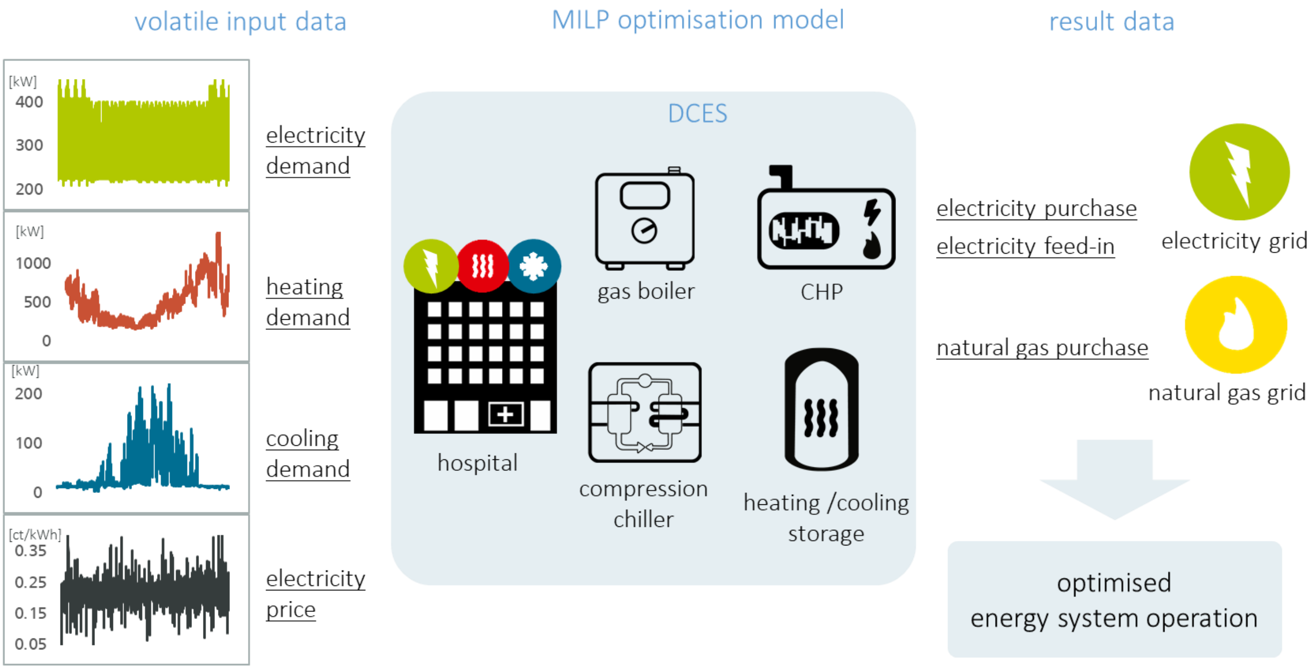

Figure 1

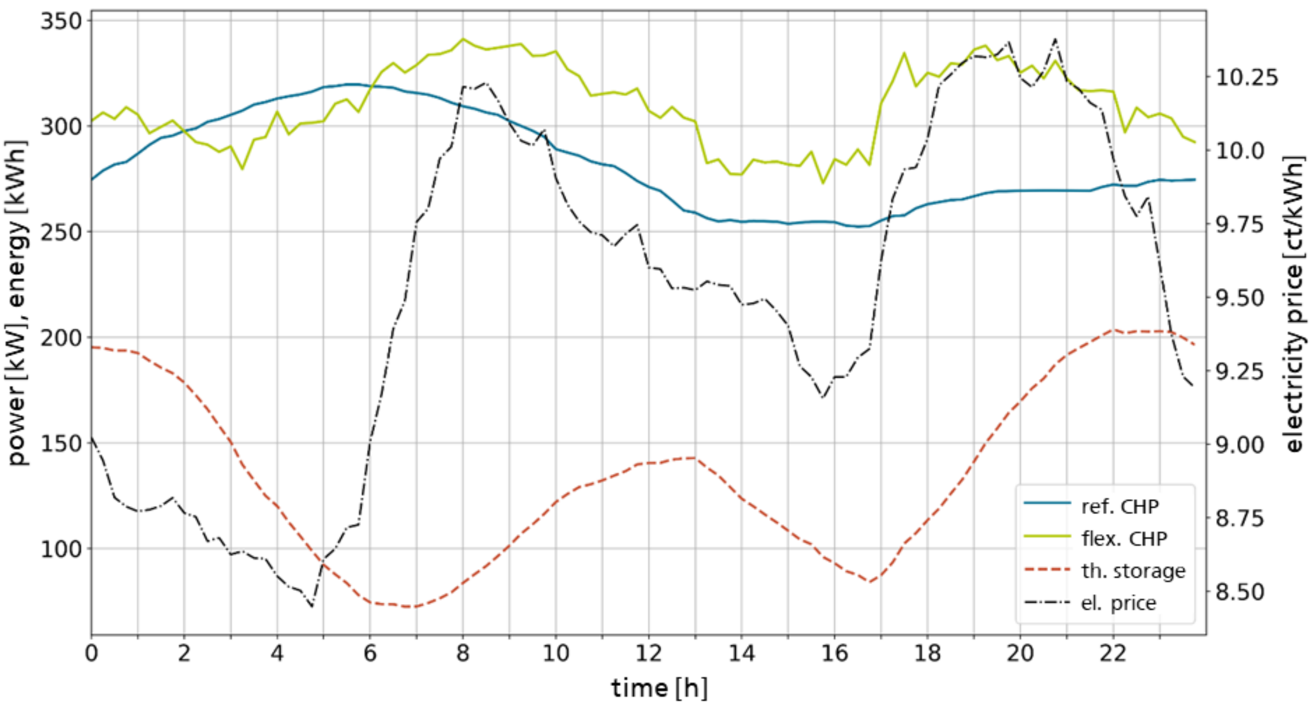

Figure 2

Session 16:35 – 17:35
Decentralised energy systems

Room: CHE/184
Chair: Jens Maiwald

Optimal economic and environmental design of multi-energy islands

Tom Terlouw, Paul Scherrer Institut

Local sustainable communities: consumer involvement for sustainable development in energy transition

Matthias Maldet, TU Vienna - Energy Economics Group

Peer-to-peer trading in decentral energy markets with pro-active consumers

Jens Maiwald, HS Zittau/Görlitz

Optimal economic and environmental design of multi-energy islands

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Motivation

Limiting global warming to 2°C requires an immediate transformation of the global energy system. Renewable energy sources have to be widely integrated, in combination with various flexibility options, to ensure a reliable and sustainable operation of the overall energy system. To achieve this, the electricity system is transforming towards distributed energy systems. Geographical islands can play a crucial role to become a forerunner towards more sustainable and distributed energy systems, since they are isolated and are usually dependent on fossil fuels imported from the mainland. This work presents the optimal design of multi-energy systems on geographical islands.

Methods

A mixed integer linear program is formulated and solved to minimize costs and greenhouse gas (GHG) emissions while meeting the energy demands of given end-users. Figure 1 shows a schematic of a multi-energy system that comprises hydrogen, natural gas, syngas, and (renewable) electricity as energy sources and carriers and uses a wide set of energy technologies considering grid-connected and autonomous configurations. Previous analyses on multi-energy systems typically exclude life cycle GHG emissions or only consider GHG emissions from system operation. However, costs and GHG emissions are generated over the entire life cycle of an energy system, and GHG emissions as well as other environmental impacts from (for example) the construction of system components can have a significant environmental burden. To fill this gap, the central contribution of this paper is to evaluate costs and GHG emissions during the entire life cycle of multi-energy systems on geographical islands. This allows to evaluate trade-offs regarding a cost or environmentally optimal design now and in the future. Further, the optimal design—the outputs from the optimization problem based on costs and/or GHG emissions—is evaluated with respect to environmental trade-offs, such as material utilization and land occupation. The model is tested on three geographical islands; Crete (Greece), Eigeroy (Norway), and Western Isles (Scotland, UK).

Results

Our model decides whether to install a set of energy technologies based on the annual system operation using hourly demand and generation profiles considering costs and environmental impacts. The model includes the following set of technologies:

- PV solar, onshore, and offshore wind electricity,
- Battery energy storage systems and sensible heat storage systems,
- Polymer electrolyte membrane electrolyzers (PEME) and fuel cells (PEMFC),
- Long-terms hydrogen storage,
- CHP units—based on natural gas and a fuel mix of renewables; syngas and hydrogen.,
- Biomass gasification,
- Electrical heat pumps,
- Solar thermal heat generation,
- Natural gas boilers,
- Battery electric vehicles.

Different system configurations are evaluated. Besides grid-connected and hybrid systems, special attention will be provided to autonomous systems entirely disconnected from the electricity grid.

Local sustainable communities: consumer involvement for sustainable development in energy transition

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Keywords: energy community, EU taxonomy, resource utilisation, sustainable development, sector coupling

Motivation

Decentralisation and consumer involvement are becoming increasingly important in the energy transition. Through the introduction of energy communities, consumers have increased opportunities to use energy sustainably. However, according to the United Nations Sustainable development goals, resource sustainability is an important aspect that must be addressed. Therefore, the European Union taxonomy for sustainable activities considers water sustainability and circular economy operations as key performance indicators for classifying sustainable activities. Sustainable communities applying such actions on the community level are predominantly based on the voluntary nature of limiting energy and resource consumption. As many consumers may not be willing to reduce consumption without further benefits, incentives for sustainable behaviour must be created. Therefore, local sustainable communities (LSC) are introduced as an extension of conventional renewable energy communities beyond the sector electricity, gas and heat. These combine the financial incentives for local energy use in energy communities with sustainability aspects of communities. Moreover, technology involvement to enable efficient sector coupling within the LSC is a critical aspect. In LSCs, business models are extended to be applicable to resource utilisation. Resource reduction is to be promoted through financial rewards for sustainable behaviour. Furthermore, disposal of resources without recovery of energy or material contradicts sustainable development goals. To use the full potential of LSCs, additional stakeholders such as wastewater treatment operators or waste management companies must be part of the LSC. In summary, the combination of business models, technology operation and industry involvement are the fundamental pillars of an LSC. This work examines the contribution of LSC operations to sustainability.

Methods

An existing sustainable community in Waidhofen/Ybbs (Lower Austria) is extended to an LSC to investigate the impact on sustainable resource utilisatoin and circle economy. Previously mentioned business models, technology operation and industry involvement are applied to the community to assess their impact. The LSC operator acts as a coordinator for the processes within the LSC. An optimisation model for sector coupling in energy communities is developed for the investigation.

Business models that are already applied in energy communities are adopted for the LSC. Additionally to electricity trading/exchange, trading/exchange of heating and cooling is implemented. To address resource utilisation, the business models are extended to water sharing and waste treatment. Water consumption prices are regulated within the LSC. Water consumption beyond a predefined threshold causes additional costs for consumers. Furthermore, consumers can gain financial benefits by reducing their total water consumption and provide water consumption rights to other LSC consumers.

Technology operation is considered in the form of joint generation and conversion technologies. The LSC operator owns the technologies and consumers can purchase electricity, heating and cooling from the LSC at a predefined price.

Waste treatment sustainability is considered by implementing industry partners in the LSC. Recovered energy from incineration is assigned to the LSC. However, the LSC must cover the costs for treatment and labour. Similar approaches are investigated for sewage sludge energy recovery by sewage treatment operator involvement in the LSC.

The impact on energy system operation and resource sustainability is investigated by the application of the optimisation model. Cost minimisation is performed in the process to assess the flows between LSC members and sectors. However, technology parameters can emerge as limiting factors. Thus they must be considered as constraints in the model.

Results

The results reflect the total optimum of the LSC operation in terms of operational costs in all sectors. Due to the consideration of multiple sectors in the LSC, a large variety of options to purchase energy and resources arises for consumers. Energy procurement from the LSC has a higher significance for consumers without their own generation and conversion technologies like PV or heat pumps. Consumers without own conversion technologies benefit from other consumers, as investments in technologies can be saved while still contributing to a sustainable energy transition. Furthermore, revenues can be generated by trading energy. Additional revenue streams result from rewarding consumers' resource savings. Consumers with a higher (stochastically predefined) willingness for resource reduction can generate higher revenues.

All tradings are performed via the LSC operator. Sector input flows arise from consumer trading and recovered energy of resource treatment like waste and sludge incineration. Trading is mainly performed in the electricity sector. In the considered setup, the most efficient heat generation option is the joint LSC heat pump. Therefore, electricity procurement from consumers for heat pump operation is more efficient than direct heat procurement from consumer heat pumps. However, by providing technology services to the LSC members, the LSC operator can generate revenues that are required for technology investment.

Costs for each consumer vary dependent on the willingness for resource reduction and on the consumers' generation and conversion technologies. Consumers having both can achieve the least costs. These aspects lead to the main conclusion that for an efficient operation of an LSC, an efficient technology use from the consumers' and LSC operator's perspective is required. Furthermore, a sustainable mindset and willingness to sustainable resource utilisation are vital aspects for consumers to benefit from the LSC in the best possible way.

Peer-to-peer trading in decentral energy markets with pro-active consumers

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Keywords: agent-based modelling, cellular approach, regional markets, consumer behaviour

Motivation

While the German energy transition proceeds, increasing shares of volatile near-load generation on the supply-side encounter a demand-side that remains spatially and temporally inflexible. Consequently, this leads to a higher level of organizing secured energy supply. Battery storage systems, power-to-x-technologies and so-called demand side management will make demand side more flexible. But, the other part of the overall solution will be the consumer behaviour itself. Decentral markets which allow pro-active buying behaviour for all consumer groups could provide potential benefits for enhanced local interconnection of generation and consumption and mitigate the overall increasing organizational effort.

Methods

A combination of Agent-based Modelling (ABM) and the so-called Cellular Approach (CA) is used to create a bottom-up simulation model of a regional, decentral energy market. Corresponding to the idea of the CA, each model entity is willing to achieve the equilibrium between generation and consumption on its own. Therefore, the entities can take advantage of the regional market and sell or buy electricity. ABM allows the simulation of imperfect markets with agents characterised by asymmetrical information and their individual preferences.

Results

Based on a real existing supply system with heterogeneous market participants the model allows to simulate different future energy generation scenarios in combination with a counterfactual market situation. The observed market scenario here, allows peer-to-peer electricity trading based on the cellular approach, all simulated in two different Renewable Energy Scenarios. The results show that this flexible trading mechanism provides the targeted financial incentives for purchasing electricity exactly when it is regionally abundant. Flexible pricing tariffs motivate consumers to adjust their consumption patterns within their individual willingness to pay. For an energy system that is becoming increasingly decentralised anyway, this has a relieving effect and the transferred amount of regionally generated electricity into higher grid levels can be reduced.