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7th AIEE Energy Symposium

Current and Future Challenges to Energy Security

– the energy crisis, the impact on the transition roadmap –

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INTRODUCTION:

CURRENT AND FUTURE CHELLENGES TO ENERGY SECURITY

– the energy transition, a pathway from low carbon to decarbonization –

The AIEE - Italian Association of Energy Economists (Italian affiliate of the IAEE - The International Association for Energy Economics) has organized this international with the scientific cooperation of the SDA Bocconi School of Management to bring together energy experts engaged in academic, business, government, international organizations for an exchange of ideas and experiences on the present and future landscape of energy security.
The previous editions of the AIEE Symposium on Energy Security, organized in Milan and Rome, were an opportunity to explore new energy trends, challenges and creative solutions for the energy security, the availability of new technologies, the emergence of new market conditions and of new market operators.
The AIEE Energy Symposium on Energy Security has become an important yearly appointment and in our uncertain world of possible pandemics organizing also this edition as a virtual event was an excellent alternative.
Following up on the success of the past editions this seventh AIEE Energy Symposium to provided a fresh look on the major forthcoming issues offering an excellent occasion to continue the dialogue and to share best practice and experience with delegates from all over the world.
The AIEE Symposium is a forum to discuss all these problems, continuing the dialogue of the past editions analyzing the transformations of the concept of energy security in this context.

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Matteo Di Castelnuovo, Director, Master in Sustainability and Energy Management (MaSEM) e SDA Associate Professor of Practice in Energy Economics, President of the Program Committee
Carlo Andrea Bollino, Honorary President AIEE, Chair of the Organization Committee and IAEE past President

Keynote speakers:

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Perspectives of the impact of energy transitions on the oil and gas producing states

Guido Bortoni, President CESI
Ensuring energy security while keeping an unbumped decarbonisation pattern

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Alberto Biancardi, Director of studies and international relations · GSE, Italy
Marco Falcone, Government Relations and Issues Manager, Esso Italiana, Italy
Silvia Pariente-David, Consultant on energy and climate change and Senior advisor – Center for Mediterranean Integration, France
Alicia Mignone, Senior Energy Advisor, MAECI and Ex President of the IEA Committee on Energy Research and Technology, Italy
Angela Picciariello, Senior Researcher, International Institute for SustainableDdevelopment - IISD

Regulatory challenges and market developments

Massimo Ricci, *D*irector of the Wholesale Energy Markets and Environmental Sustainability Department and Head of Energy Division of ARERA - The Italian Energy Authority
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Elisa Scarpa, Deputy Director Market Strategy & Structuring Edison, Italy

Energy industry challenges to a low-carbon economy, the RES and gas role in the transition

Carlo Di Primio, AIEE President, Italy
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Xavier Rousseau, Senior Vice President Strategy and Market Analysis, Snam
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Leonardo Artico, Head Industry and Skills Development, Motus-E, European Platform for Mobility, Italy
Franco Del Manso, International Environment Affairs Manager UNEM, Italy
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Luciano Martini, Director Department of Transmission and Distribution Technologies, RSE, Italy
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Alexander Akolo, Dilinna Lucy Nwobi, and Adejumoke Akinbusoye

WILLINGNESS TO PAY FOR UNINTERRUPTED ELECTRICITY SUPPLY FROM INTERCONNECTED SOLAR MINI-GRIDS IN A DEVELOPING ECONOMY

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Overview

Affordability is one of the hallmarks of communal electricity. Many communities in Nigeria and in particular South-West Nigeria, suffer the misfortune of the non-availability of quality and adequate electricity supply. However, the deployment of Interconnected Solar Mini-Grids (ISMGs) in these underserved communities could guarantee the service commitments of the Electricity Distribution Companies to these areas. Six of these underserved rural communities in South-West Nigeria: Ilushin, Bolorunduro-Efire, Ofiki, Tede, Aiyesan, and Araromi-Obu across Ogun, Oyo, and Ondo states were purposely selected for this study. This study aims to estimate the monthly willingness to pay (WtP) amount for uninterrupted electricity supply from ISMGs and investigate the predictors of WtP in the selected communities.

Method

Data was collected through Focus Group Discussions (FGDs) conducted amongst electricity consumers in the selected study communities. Six (6) participants each were selected at random from the study areas for the FGDs. A set of themes was developed from the transcriptions of the conducted FGDs in the selected communities to analyse the data and make patterns of meaning in the data sets. The thematic analysis technique. A qualitative approach was employed to investigate the WtP for uninterrupted electricity supply.

Results

The study found that all the participants were either connected to the distribution networks of the Ibadan Electricity Distribution Company Plc or the Benin Electricity Distribution Company Plc. However, all participants lamented the poor quality of electricity supplied to their communities, and in the case of the Aiyesan and Araromi-Obu communities, participants lamented that they had not had

electricity supply in the past 16 years. None of the participants was satisfied with the level of electricity supplied to their respective communities. Conversely, participants in the Tede community expressed their lack of interest to connect and pay for an uninterrupted electricity supply from an ISMG. This is as a result of their desire to enjoy stable electricity like their surrounding communities. In the remaining communities, the participants expressed their willingness to connect to ISMGs due to its perceived benefits such as reduction in noise pollution, attraction of businesses and investors, access to information (television and radio programs), etc.

The monthly WtP amount of most of the participants in the study areas was N2,500. Most of the participants stated that as long as there is a guarantee from the Mini-Grid developer and operators of uninterrupted electricity supply, they are willing to connect and pay for electricity from ISMGs. The guarantee of uninterrupted electricity supply was the factor that most influenced the participants' WtP for uninterrupted electricity supply from ISMGs.
Other factors in rank-order include installation of prepaid metres, affordability of tariff, domestic and business uses, security, rural-urban migration, noise pollution, and high fuel price Participants' level of education and house ownership did not impact participants' WtP for solar energy.

Conclusions

Results from the study reveal that the participants are willing to pay between N1,500 to N10,000 per month for uninterrupted electricity supply from ISMGs. Its predictors are the guarantee of uninterrupted electricity supply, installation of prepaid metres, affordability of tariff, domestic and business uses, security, rural-urban migration, noise pollution from generators, and the high petrol price.

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Iryna Sotnyk and Tetiana Kurbatova

FORMING SOLAR BUSINESS PROSUMERS CLASS: THE CASE OF UKRAINE

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Overview

The concept of prosumerism plays an essential role in implementing the green energy transition for many nations worldwide since it involves the self-consumption of renewable energy generated by small energy producers. The development of prosumerism contributes to power supply decentralization, energy market liberalization, and the spread of using renewable energy technologies and smart grids.

The leading countries, which have significantly succeeded in green power advancement, have positive achievements in prosumerism promotion. For transition and developing economies, prosumerism is a new but prominent way to struggle with energy poverty and ensure energy security. A vivid example is the transition economy of Ukraine, which first experienced political pressure and gas blackmail, and later unprovoked military aggression by the former main energy importer - the Russian Federation. Therefore, the research aims to assess the prospects of forming a class of business prosumers in Ukraine in the solar photovoltaic energy sector.

Method

We examine the conditions to form a class of solar business prosumers in Ukraine: enterprises that use electricity generated by their solar power plants to meet their energy needs. To assess the feasibility of such an energy transition, we analyze the state policy for stimulating solar energy advancement in the industrial sector and the results of its implementation. We use investment analysis tools and compare the decision about the transition by green energy producers, namely industrial photovoltaic solar power plants, with that of prosumers. The net present value, profitability index, and discounted payback period of construction projects of industrial photovoltaic solar power plants with capacities of 100, 300, 500, and 700 kW located in the Sumy region were evaluated. Three options for the use of green electricity were considered: 1) sale of 20% of generated electricity at a feed-in tariff and self-consumption of 80% of electricity, 2) sale of 50% of generated electricity at a feed-in tariff and self-consumption of 50% of electricity, 3) self-consumption of 100% electricity.

Results

We have found that stimulating state policy remains the main factor in solar energy development in Ukraine. It ensured the growth of green energy in the total power mix up to 9% in 2009-2021. However, the formation of the prosumer class directly depends on the competitiveness of small solar power plants. The obtained results indicate that projects for constructing industrial photovoltaic solar power plants with a capacity of 300, 500, and 700 kW are profitable at the current market electricity prices and feed-in tariffs. However, constructing a 100- kW photovoltaic solar power plant is not competitive when selling 80% and 50% of the generated electricity at the feed-in tariff. The profitability of all projects rises with an increasing self-consumption share of the generated electricity. That is, the most profitable option for all projects is the third one with 100% of the generated electricity self-consumption.

Conclusions

By assessing the economic feasibility of 100-, 300-, 500- and 700-kW industrial photovoltaic solar power plants projects to implement in the Sumy region with three different energy-use options, we proved that Ukraine has all conditions to develop a solar business prosumer class.

We confirmed that an increase in the self-consumption share improves the projects' profitability and motivates the industrial photovoltaic solar power plants' owners to become prosumers. Therefore, with the preservation of current market conditions and state regulation of the sector, Ukraine has every opportunity to form a class of business prosumers in the photovoltaic solar energy segment.

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Amir Alborz Moezzi, Alireza Shadmand, Fazel M. Farimani

EU ENERGY RESILIENCE, A FINANCIAL ANALYSIS OF EXTRA-TERRITORIAL SOLAR PV POWER PLANTS AS A SOLUTION

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Overview

Global energy crises and climate change have become fundamental issues in the past decades; economic and geopolitical conditions tend to make countries more dependent on independent energy resources. These matters have advanced investments in renewable energy projects. Due to the environmental effects and resource limitations of fossil fuels, renewable energy projects have become the forerunner. In addition, one of the most preferred energy resources is solar power. Therefore, investing in extra-territorial electricity projects (due to lower marginal cost) could be a viable solution to achieve energy resilience and mitigate the costs of political uncertainty. Considering Iran's photovoltaic power potential, it would be a premier choice for the EU to invest in and use. This paper assesses an experimental small-scale commercial power plant scalable for large-scale exploitation in Iran.

Methods

The initial step in establishing a solar PV power plant utilizing solar panels is to select a suitable location and afterward run a simulation to check its technical and financial feasibility. First, in order to achieve electricity exportation objectives, four cities – Khoy, Urmia, Mako, and Salmas – are chosen based on closeness to the border and availability of power transmission lines; The study uses eight parameters to determine the optimal region: altitude, sunny hours, wind speed, maximum temperature, relative humidity, all-sky Insolation clearness index, average precipitation, and 2-meter temperature. All the data was gathered, normalized, and weighted. The statistical gap was removed using a multiple-criteria decision-making (MCDM) approach, precisely the Order Performance by Similarity to Ideal Solution (TOPSIS) method. The optimal region was found by running a TOPSIS code written in Python. For the economic analysis, there are four major solar PV power plants: standalone, grid-tied PV with and without battery bank, and hybrid PV (Berwal AK et al., 2017). An on-grid system of 10MW with potential for scalability was selected. Subsequently, the system was designed and simulated using PV*SOL software; the solar panel model, energy inverter, installment costs, project lifetime, import tariffs, and tax exemptions were interpolated to estimate the project costs and revenues. At last, all the data was processed to calculate land area and financial feasibility by calculating Levelized Cost of Energy (LCOE), NPV, IRR, and Simple Payback Period.

Results

The score of each of the four regions was obtained after doing the necessary calculations for the eight criteria on each region, and then the weighted normalized data was interpolated into the TOPSIS code to select the suitable location for setting up a solar PV power plant. The optimal site was determined to be Khoy city, in West-Azerbaijan province (38.5455° N, 44.9590° E). For the capacity of 10MW, an area of 0.56km2 has been calculated.

To conduct a feasibility study, after the proper location was chosen, a simulation in PV*SOL software was run -with a project lifetime of 25 years- to calculate the costs and revenues of the project. Investment costs considering 20% import taxes are 12.481 million USD, yearly operation and maintenance (O&M) costs have resulted as 400 thousand USD, and annual energy production has resulted as 26.28 GW. The yearly revenues in the average-case scenario of electricity price in the EU have resulted in 6.9 million USD, and in the worst-case scenario, 6 million USD.

For the LCOE, NPV, IRR, and Simple Payback Period of the project, six basic assumptions have been considered: 1- The O&M has been calculated based on the PV*SOL software simulation; 2- a tax exemption of 10 years has been integrated (based on official Renewable Energy Support Policies in Iran); 3- yearly panel degradation is assumed to be 0.5% (based on the PV panels' producer data sheets); 4- discount rates are as follows: 2.5%, 5%, and 16.46%

The calculated results are presented in *Table.1*.

Electricity Price Scenarios	NPV (i = 2.5%)	NPV (i = 5%)	NPV (i = 16.46%)	IRR	Simple Payback Period	LCOE
Europe (Average Electricity Price)	$ 94,000,000	$ 72,000,000	$ 29,000,000	1.05	2.94	0.07$ kW/h
Europe (Min Electricity Price)	$ 79,000,000	$ 61,500,000	$ 24,500,000	0.96	3.25	

Table.1 - Calculated NPV, IRR, Simple PP, and LCOE of the project

Conclusion

In this study, the feasibility of extra-territorial investment and exploitation of energy to the EU has been studied regarding the climate and techno-economical aspects. Results showed that Iran has a great potential to generate solar electricity via photo voltaic rays in a profitable manner. Based on the results, the final price of electricity generation in the worst-case scenario is significantly cheaper than in the EU. Furthermore, the calculated payback period shows that the investment will be repaid fairly shortly, making the project almost risk-free. As a result, this paper demonstrates the feasibility and lucrativeness of investing in Iran to reinforce Europe's energy safety because of the abundance of suitable locations to establish solar farms.

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David P. Brown, Andrew Eckert, Douglas Silveira

STRATEGIC INTERACTION BETWEEN WHOLESALE AND ANCILLARY SERVICE MARKETS

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Overview

In electricity markets, system reliability requires the instantaneous balancing of supply and demand. In addition to the wholesale electricity market, the procurement of various ancillary service (AS) is vital in achieving this objective. An important design feature is whether ancillary service markets clear simultaneously or sequential with wholesale markets. We propose a model to study the strategic implications of simultaneous versus sequential timing when firms compete in the ancillary services and wholesale electricity markets. Considering the case where ancillary services markets clear before wholesale markets, we demonstrate that when firms face increasing marginal cost curves, a strategic incentive to reduce ancillary services output and, consequently, lower their marginal costs in the wholesale market arises. We employ data from Alberta's electricity markets to demonstrate the quantitative implications of our findings. Our numerical results show that the strategic commitment effect has a small impact on wholesale market outcomes but a large impact on the equilibrium in the ancillary services market, elevating the market-clearing price.

Methods

We combine theoretical and empirical frameworks to analyze the strategic implications of simultaneous versus sequential market-clearing in wholesale-AS market competition. Our theoretical analysis is based on a model of wholesale and AS market competition to understand how changes in market timing can impact equilibrium market outcomes. We assume that generators compete via Cournot competition in wholesale and ancillary service markets. Importantly, the provision of AS output impacts a generator's cost of providing wholesale output because it precludes the use of a portion (or all) of a generation unit's available capacity in the wholesale market. Consequently, this creates a linkage between the AS and wholesale market output choices impacting strategic behavior and equilibrium outcomes in both markets.

Our empirical analysis employs data from Alberta`s electricity market – covering the period January 1, 2020 to December 31, 2020 – to illustrate our model's results in a setting that reflects key features of real-world electricity markets. We model the Alberta setting as one in which there are four large strategic firms behaving as Cournot producers in both the AS and wholesale markets, taking the supply from price-taking fringe producers, and imports in the case of the wholesale market, as given[1]. In the wholesale market, we formulate the price-elastic demand function facing the strategic Cournot producers as the perfectly price-inelastic wholesale demand, net of price-responsive supply from importers from neighboring jurisdictions and fringe producers. In the AS market, the AS demand function represents the pre-specified AS quantity set by the Alberta Electric System Operator (AESO), net of price-responsive supply from fringe firms that are observed to compete in these auctions. Unlike the wholesale market, importers cannot supply the AS product.

We compute unit-level marginal cost functions for the four large strategic firms and estimate linear marginal cost functions associated with generating output. In addition to having generation resources that can be called upon to supply output (i.e., "dispatchable resources"), firms have must-run generation units (e.g., wind and cogeneration) whose supply into the wholesale market is exogenously determined and has zero marginal cost.

[1] See Brown, Eckert, and Shaffer (2022) for additional details on firms' offer behavior in Alberta's electricity market

We take this supply as given and assume the strategic firms make output decisions in the wholesale and AS markets using their dispatchable units. After establishing parameter estimates for the wholesale and AS residual demand functions and firms' marginal cost functions, we adapt our model to consider four firms and permit zero marginal cost must-run generation, and use the equilibrium wholesale and AS market output levels to numerically solve the simultaneous and sequential move models for each hour in our sample. In each setting, our model can be translated into a mixed complementarity problem (MCP) where we allow for the presence of a zero-bound on AS market output. We utilize the PATH solver in GAMS and the University of Wisconsin's NEOS server to solve the large number of model cases (NEOS, 1998; Ferris, 2000).

Results

Our theoretical results show that, with sequential timing, firms reduce AS market output because of the strategic effect[2] in the wholesale market, resulting in increased wholesale market output. This result in a decrease in the wholesale price compared to the case where the AS and wholesale markets clear simultaneously.
In addition, we show that moving from simultaneous to sequential timing causes firms to decrease the AS market output in order to reduce their subsequent marginal costs in the wholesale market, resulting in a higher AS price.

Our numerical results demonstrate that the presence of the strategic commitment effect has a small impact on wholesale market outcomes. On the other hand, we find that the presence of the strategic effect has a large impact on the AS equilibrium outcome, leading to AS price increases ranging from 8% to 33%. The large effect in the AS market is driven by the fact that the market is highly concentrated and fringe supply is highly inelastic. As a result, small changes in output by the large firms in the sequential setting can have a sizable impact on AS market outcomes. Alternatively, the wholesale market is larger in magnitude and has a more elastic fringe supply function. This induces smaller differences in equilibrium outcomes in the sequential versus simultaneous market-clearing cases.

When looking across both markets, we find that total procurement costs only increase by a small margin in the sequential move setting. While the AS prices increase considerably, the AS market is relatively small compared to the wholesale market. Consequently, the small price reductions in the wholesale market counteract the large increases in the AS price. This demonstrates that looking only at the AS market outcomes in isolation may lead to conclusions that the elevated market power results in a considerable reduction in consumer surplus. However, this overlooks a key component of the overall market outcome, the impact on wholesale market competition. Our findings stress the importance of considering the strategic linkages between AS and wholesale markets, and the overall impact on market outcomes and procurement costs across both markets.

Conclusions

We demonstrate that a strategic incentive arises in the setting where the AS market clears prior to the wholesale market. In particular, we show that firms have an incentive to reduce their AS output in this setting because it allows them to commit to competing more aggressively in the subsequent wholesale market.
The presence of this strategic incentive leads to a higher AS market-clearing price, but puts downward pressure on the wholesale price. Consequently, the net effect of moving to sequential timing on the total procurement costs across both markets is ambiguous.

[2] The strategic effect reflects the impact of a firm's AS output on its rivals' wholesale output

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ROBUSTNESS ANALYSIS OF POWER SYSTEMS WITH A HIGH SHARE OF RENEWABLES

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Overview

The objective of this research work is to evaluate the behaviour of power systems with different levels of renewable energy share under contingencies in the electrical grid. Papers [1], [2], [3] study the influence of renewables on the robustness of the electricity system, although our contribution additionally considers the effect of the interdependence between the electricity and gas systems. Today, both infrastructures are closely related, since natural gas has become the main backup source to meet energy demand when sufficient renewable generation is not available.

Method

The assessment of the robustness of electricity systems with integration of renewable generation must consider the interactions between gas and electricity transmission networks. This article uses the software SAInt (Scenario Analysis Interface for Energy Systems), [4]. This tool is based on a mathematical formulation of models for electrical networks with a quasi-dynamic behavior, for gas networks with a time evolution of the fluid conditions in the pipelines, and a formulation to represent the interconnections between both systems.

Results

The robustness analysis is applied to a case study of Belgium, since the general data are public (generation, electricity and gas consumption, and technical constraints of each infrastructure component) [5], [6], [7]. The study is carried out during the 24 hours of a critical day for electricity demand and gas consumption with low generation availability. Due to the big cold wave during the study day, the Belgian electricity system suffered several contingencies such as the freezing of wind turbines, failures in the gas supply to gas-fired power plants, and failures of several transmission lines. This paper analyzes four cases:

- Base case without contingencies (Case 1)
- Base case with contingencies (Case 2)
- Case with higher share of renewables and without contingencies (Case 3)
- Case with higher share of renewables and with contingencies (Case 4)

In Cases 3 and 4, renewable energy represent 38% of the electricity generation mix compared to 21% in Cases 1 and 2.
From the results of the simulation of the electrical system, the electricity that could not be supplied in the network demand buses in each hour has been obtained. Similarly, the evolution of the gas not supplied in the consumption nodes of the gas network is also obtained. Case 2 presents an increase of 14% of the electricity not supplied regarding case 1, as several simultaneous contingencies occur, including line outages and generator shutdowns. In addition, in this case, the contingencies in the grid has a more significant effect on the gas system by affecting buses that fed compressor stations, causing a lack of gas supply.

In the cases with a higher share of renewable generation, there have been significant changes. Case 3 reduces average gas consumption because of the renewables contribution, which has an impact on the fluid stored in the network's gas pipelines by 2% with respect to Case 1. Case 4 increases the electricity not supplied due to the lack of generation assets to mitigate the imbalances derived from the simulated events.

It should be noted that as renewable generation increases in the grid, more critical problems appear in the supply, where variability in generation defines the system performance.

Conclusions

From a long-term energy perspective, it is verified that a future consisting entirely of renewable generation is not possible with today's technology. Robust energy infrastructures must remain in place while the energy transition is successfully completed. The objectives of decarbonization of the electricity sector cannot be achieved without energy storage to back up the intermittency of renewable generation (large-capacity electrical batteries, hydroelectric pumping or Power-To-Gas facilities).

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ON THE IMPACT OF NUCLEAR POWER GENERATION ON ELECTRICITY SPOT PRICES: A FRENCH PERSPECTIVE

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Abstract

The soaring power prices on businesses and households in Europe has became the main topic discussed in EU leaders's meetings.
Indeed, European electricity prices surged in last year, driven mainly by two fundamental determinants : natural gaz supply from Russia, and problems with French nuclear plants.

In this paper, we explore the impact of nuclear plants generation on the spot price of electricity in France, taking into account power load dynamics in France and prices of imported natural gas in Europe as control variables.
Our main results show that there is a strong negative relationship between nuclear electricity generation and power spot prices. Indeed, the supply squeeze, caused by a wave of repairs at nuclear power stations of a country which deriving 70% of its electricity from nuclear energy, induced an historical jump in electricity spot prices in France.
Moreover, the soating of gas prices,as Russia has cut the volumes it sens to Europe after its invasion of Ukraine, exacerbated the upward effet of nuclear generation on french power prices.

Keywords: Electricity spot prices, Nuclear plants, Natural gas, Load

Introduction:

Due to Covid-19 pandemic and successive lockdowns, the mean of electricity spot prices reached a low record of 32 €/MWh in 2020. However, the progressive opening of the economy induced an increase in these prices during the first semester of 2021. Indeed, mean of electricity spot prices during this semester was around 55 €/MWh ; which seems to be ''normal'' prices in comparison with historical power prices in France and Europe.

But, during the 2021 second semester, this mean reached 159 €/MWh ; an increase of around 300%. At the first semester of 2022, and due to russian invasion of Ukraine, the power prices jumped to 221 €/MWh and this increase dynamics is still continuing during 2022.
From a french perspective, although the surge in power prices in Europe was driven by record gas prices as Russia curbed its supply, its seems that the wave of repairs of nuclear power stations is playing a central role at the historical jump in electricity spot prices in France.
Indeed, France is deriving about 70% of its electricity from nuclear energy. EDF (Electricité de France), operating the world's largest fleet of nuclear reactors, is challenged by the nuclear power shortage. France, once Europe's top power exporter, providing about 15% of the region's total power generation is not producing enough nuclear energy. For the first time, France has become a net power importer as its own production of nuclear energy hit a 30-year low.Thus nuclear supply squeeze is turning into an economic threat more than Russian gas flows.

In order to quantify the impact of nuclear energy production on spot electricity prices taking into accout the imported natural gas prices and load dynamics as control variables, we carry out an empirical analysis on a data sample running from 1/1/2021 to 10/1/2022 of the these variables.

Our empirical results show that the spot electricity prices was negatively impacted by nuclear power generation and positively impacted by natural gas prices.

The negative impact of nuclear power generation induces an inverse relationship as the decrease in nuclear generation will have an impact of making electricity power prices much higher. Indeed, according to the merit order principle, the nuclear plants have much lower marginal prices than thermal plants (coal, natural gas).Thus, the less nuclear electricity is produced, the more the power equilibrium price will be higher

The positive impact of gas prices can be explained by the fact that, in the EU energy system, the wholesale electricity price is set by the last power plant needed to meet overall demand. This 'marginal' plant is natural gas plant. The imported natural gas, after Russia has cut the volumes it sends to Europe, and amid fierce global competition for non-Russian gas, is continuously soaring. The effect of this price surge has been to drive up the price of producing power from gas in Europe, resulting in higher electricity prices as the power price is linked to natural gas.

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Diyun Huang and Geert Deconinck

COUPLING EUROPEAN LONG-TERM ELECTRICITY MARKET WITH JOINT ENERGY AND TRANSMISSION RIGHT AUCTION – INSTITUTIONAL SETTING, MARKET MECHANISM AND GRID MODELLING COMPARISON BETWEEN NODAL PRICING AND FLOW BASED ZONAL PRICING

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This research on implementing joint energy and transmission right auctions in European long-term market is unfolded with three dimensions. First, the current and future challenges for European electricity market are analysed and development of long-term cross border market is advocated. Tapping the potential of renewable energy resource complementarity over large geographical areas with cross-border market creates a more optimized and lower cost system. The establishment of long-term cross-border market with bilateral contracts or wholesale energy sales well in advance is of vital importance for the future. Market mechanism based on price signals is essential to lower transaction costs for cross-border cooperation, as it could render administrative negotiations for cost allocation across borders less necessary. Price stability for consumers is always crucial aspect of market design. In the wake of recent energy crisis, the importance of stable price from long-term markets for consumers and instruments to hedge against spot market volatility is greater still. At the same time, certain contractual arrangements in long-term market such as power purchase agreement in combination with the physical or financial transmission rights can generate stable cash flows for renewable investors. The design and allocation of cross-border transmission rights stand at the centre of the long-term market development. Is there another way to design long-term transmission rights to facilitate the long-term cross-border market?

Second, the joint energy and transmission right auction (JETRA) developed by O'Neil et al is proposed for long-term cross-border market development [0]. JETRA provides the possibility to auction energy, financial transmission rights and physical transmission rights simultaneously. Looking back, prioritized long-term interconnection access prevailing prior to liberalization had been examined by European institutions with critical views due to its anti-competition effect [0].

The focus of European electricity market has been on the development of spot market. The key characteristic that differentiates the long-term auction from the priority long-term interconnection access is that the market clearing in JETRA is financial prior to the real time market. The market outcomes are liquidated after each round. Temporally, it does not give prioritised transmission capacity to the long-term market participants compared with the ones in spot market. Liquidated outcomes imply that auctions prior to real time do not interfere with physical dispatch to optimize the whole system according to real time constraints. In particular, the pricing and settlement rule is designed to link products in multiple timeframes and keep consistency between long-term and spot markets. Market participants that procure energy contract or transmission rights in the previous auction round will be paid the amount to obtain the exact same quantity of energy or transmission rights in the current auction. This could enable the network users that procures energy or transmission rights to financially hedge the spot market price and congestion risk.

Third, a case study based on a stylised network is used to illustrate the implementation of JETRA under nodal and flow based zonal pricing. The flow-based market coupling mechanism currently implemented in day-ahead market is carefully examined and adapted for JETRA under zonal pricing.

Governance of day-ahead market coupling revolving around zonal pricing determines the institution set ups and their functions. TSOs and power exchanges are responsible for grid and market operations respectively within bidding zones. By comparing the auctioning outcome between nodal and zonal market, the bottlenecks of zonal market design in supporting the transmission right and trade potential across borders are identified. In the long-term time frame, an important aspect to examine is the role of higher uncertainties and how it amplifies the inefficiency from current institutional set ups and flow-based market coupling methodology. Introducing the financial transmission rights in the auction backed by bilateral contracts in JETRA, prediction of transaction patterns across border is much more challenging for TSOs in the long-term time frame. At the same time, precondition of well-functioning hedging for cross-border trade is to keep the firmness of financial transmission rights. To fulfil the precondition, a much more conservative grid modelling has to be made to ensure the firmness of FTR in the forward market [0]. We investigate this by two aspects: 1) comparing grid modelling process and parameters; 2) comparing how effective the hedging functions under nodal and zonal pricing by the total costs for grid users.

Compatibility of current European flow-based market coupling zonal design with JETRA is problematic when it comes to implementing JETRA to couple long-term market. Increasing uncertainties in the long-term time frame further impedes TSOs to calculate efficient flow-based market coupling parameters. At the same time, including hedging products such as cross-border financial transmission rights brings higher requirement for grid modelling of joint auctions. This has profound implications for the effectiveness of the hedging instruments and long-term cross-border market development. The effect of coupling the long-term market based on the flow-based market coupling institution and mechanism is analysed on the system operator and grid users respectively.

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Siqi Meng, Renjin Sun

HOW DOES THE PROVINCIAL RENEWABLE ENERGY DEMAND EVOLVE UNDER MULTIPLE INFLUENCE FACTORS? AN EMPIRICAL STUDY BASED ON CHINESE DATA

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Abstract

Renewable energy is an important engine to promote the improvement of environmental quality and ensure energy security all over the world, and its demand has different evolutionary characteristics in spatial and temporal dimension. Based on this, the article uses the data of China's 30 renewable energy power consumption levels, renewable energy policy, green innovation, GDP, population, industrial structure upgrading, energy efficiency and fossil energy consumption from 2012 to 2021, based on the expanded STIRPAT model, and through spatial measurement methods, considering both the horizontal dimension of space and the vertical dimension of time, the evolution characteristics of renewable energy demand in the province under various influencing factors with renewable energy policy and green innovation as the main research object are analyzed empirically.

The empirical results show that:

(1) China's renewable energy demand presents obvious spatial spillover effect, and presents the spatial positive correlation distribution characteristics of "high- high" type agglomeration and "low-low" type agglomeration.

(2) The renewable energy policy has a positive effect on promoting the demand for renewable energy. From the horizontal spatial dimension, it shows a positive spatial spillover effect, but there is a certain effective distance threshold within 1200 kilometers. From the perspective of vertical temporal dimension, the promotion effect on demand as a whole has a marginal increasing trend, among them, 2016-2019 showed a significant upward trend.

(3) From the perspective of sub-regions, there are certain regional differences in the impact of basic variables dominated by renewable energy policy and green innovation on renewable energy consumption. Green policies and innovations in the eastern and central China can significantly stimulate the demand for renewable energy, and the central region has a stronger driving effect.

(4) About 13% of the impact of renewable energy policy on the demand for renewable energy is indirectly realized through green innovation. Finally, this paper puts forward targeted policy recommendations from the perspective of sub resource areas.

Key words: Renewable Energy Demand, Renewable energy policy, Green Innovation, Spatial Spillover

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EVALUATING THE INTERACTION BETWEEN ENERGY EFFICIENCY, DEMAND RESPONSE AND ELETRIC SYSTEM RELIABILITY

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Overview

The integration of EE, DR, and ESR is an emerging area of research with limited implementation experience. To the authors' knowledge, previous studies have focused on the interactions of EE and DR and the interaction between EE and ESR. However, there is no study aimed at demonstrating, with empirical data, the interaction between EE, DR, and ESR. Traditional EE measures combined with DR and other technologies, such as storage systems, can lead to increased energy productivity by creating a more flexible and reliable energy system. EE affects the available load by reducing or shifting it from peak to off-peak periods (and vice versa) or increasing the potential for flexibility. Following an EEI (suppose the installation of a heat pump), the load shape is higher in some hours, which increases EE availability and encourages greater participation in DR programs. In this case, EE and DR complement each other. The relationship that exists between EE and ESR interventions is discussed in [1, 2] which shows that by using a sufficientlyhigh level of energy efficiency, there will be fewer outages, which have a positive effect on system reliability [3]. From the grid operator's point of view, efficient energy use (especially during critical hours)gives benefits to the power system by making it more reliable and strengthening its ability to adapt to challenges. This results in lower demand in terms of DR.

Methods

This paper aims to improve knowledge and demonstrate the validity of EE interventions (EEIs) through the use of a tool for evaluating the benefits of energy efficiency measures (EEMs) in the environmental sphere and in terms of DR and ESR. In order to evaluate this interaction, a quantitative method is proposed and validated on real results in an Italian case scenario, taking into account the analysis of smart meters data for residential users located in southern Italy in Calabria. The proposed evaluation methodology uses as input data the hourly profiles of the base users (before an EEI) and the estimated profiles (after an EEI); it also employs the national average fuel mix used for the production of the electricity fed into the electricity system, the number of annual peak hours estimated by the TSO, and the demand for availability in terms of DR. Input concepts are briefly explained below:

- **A basic hourly profile:** This is a utility profile on which no EEI has beeninstalled.
- **A measured hourly profile:** This is a user profile on which EEI has beeninstalled.
- **The hourly national energy mix:** This is the set of primary energy sources used to produce the electricity that is subsequently fed into the national electric system for sale to the end user.
- **The number of critical hours in the electric system:** The peak is defined as the set of the number of hours in the year when the probability of system inadequacy is greatest, i.e., the hours when there is a poor ability of the system to meet the demand for electricity within predeterminedlevels of safety and quality. The TSO determines them for the capacity market. In particular, the adequacy assessments verify the ability of the electricity system to cover the demand for electricity with the necessary reserve margins at all times during the period under consideration. For this reason, annual peak hours are identified as the hours with the lowest adequacy margin on a national basis for each calendar year.

In detail, the used indicators are:

- **DR demands from the electric system:** Reliable operation of the electric system requires a perfect balance between real-time supply and demand. This balance is not easy to achieve since both demand and supply levels can change rapidly and un expect
- **CO_2 emissions**—in order to estimate social benefits, an estimate of CO2 savings will be made, taking into account the hourly energy production mix in the system;
- **change in system demanded energy (DR)—**to estimate the DR benefits, the amount of energy made available for the DR service will be evaluated by considering the historical demands of the electric system;
- **change in energy reflecting on critical hours**—in order to estimate the benefits of the electric system, the difference in the amount of energy that occurs during the critical hours after the EEI will be evaluated.

Based on the collected data, an aggregation of users was evaluated with real hourly profiles covering the period from January 2020 to August 2020. These results show how efficient energy use may affect DR resource availability and power systems reliability. Based on the collected data, an aggregation of users was evaluated by dividing 1 MW by the average power of the considered profile. The number of consumers aggregated is 2247. Based on aspects considered let us now analyzed the effects of EE interventions, reported in *Table 1.*

		BASE Profile	**HP Profile**	**HP&TI Profile**
DR	Nr. Successes	726	1306	1306
	Nr. Failures	974	394	394
	En. Successes (MW)	726	1306	1306
	En. Failures (MW)	974	394	394
	Remuneration Successes [€]	14769,97	23383,83	23383,83
	Remuneration Failures [€]	-148877,4	-62738,8	-62738,8
	Total remuneration [€]	**- 134107,43**	**-39354,97**	**-793965,93**
CO_2	Total tonnes CO_2	10017	2600	2508
Critical hours	Nr. critical hours with higher load HP (max. 500)	-	442	419
	Tot. Higher load (MW)	-	471,5	240,2

Table 1 **-** Comparison of profiles under three factors: the amount of change in energy made available in the DR, the amount of CO_2, and the change in the amount of energy during critical hours

Concerning the first aspect related to the energy made available in the DR, it can be observed that:
In the basic profile, the number of successes in providing this service is 726, which is significantly lower than the number of failures recorded, which is 974. This figure tells us that users are unable to provide this service. They participate in DR but only record losses.
In contrast, after EE intervention with the heat pump, the number of failures decreases, recording only 394 failures, and 1305 services were successfully provided. In this case, with the heat pump, electricity consumption increases, so the availability given to the electrical system to cut the load increases.
It was also observed that the HP + TI profile shows exactly the same data as the HP profile, with 394 failures and 1305 successful delivery. Therefore, the addition of thermal insulation brings EE benefits but gives no DR benefit because the load curtailment can occur at times when DR service is not required. It also has no impact on demand response, which is why the two profiles record the same results.

The second aspect measured is the efficiency of the interventions carried out by assessing the reduction of CO_2 emissions associated with the energy needs of this aggregation of users.
As expected in the middle of the day the energy consumption is high but the CO_2 produced is not so different from the morning hours when the energy consumption is very low. This is due to the energy produced by RES (especially photovoltaic systems).

In the evening hours, when there is no more availability of renewable energy the energy consumption drops again but the CO_2 produced remains very high.

	BASE Profile	*HP Profile*	*HP & TI Profile*
CO_2	10017	2600	2508

Table 2 **-** The Total tones of CO_2 emissions obtained for each profile

The critical hours are the third aspect that is evaluated, seeing the critical hours for the electrical system, hours in which there is a more significant load and therefore a greater risk to having a system blackout.

	BASE	**HP**	**HP & TI**
Nr. critical hours with higher load HP (max. 500)	-	442	419
Tot. Higher load (MW)	-	471,5	420,2

Table 3 **-** Comparison of critical hours to the base case

Analyzing the critical hours in the HP profile compared to the base profile, the number of DR related failures decreases, but the number of critical hours where we have higher load increase increases to 442. Considering the HP+TI profile, the number of critical hours decreases to 419, so a benefit from the power system perspective can be observed.

Conclusions

In this paper, the authors developed a method that suggested a related tool able to catch the benefit of an EEI in terms of social benefits, i.e., CO_2 emission reduction, DR availability, and electric system reliability. A possible solution, especially for EPC, is the pay-for-performance contract (P4P). P4P has already been implemented for several years in the United States. Currently, we are observing this concept being introduced in the EU regulatory framework with the SENSEI project, which proposes an advanced EPC version that combines pay-for-performance (P4P) arrangements with energy performance contracting (EPC). The P4P model allows EE values on the entire value chain to be offered on a bidding
platform to players in the market as an investment. This approach encourages long-term investment and transparent cash flows (pay) in energy-efficient buildings by metering energy savings smartly and achieving a return on investment (ROI) based on proven and measured savings in the buildings (performance).

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POTENTIAL REDUCTION PROJECTION OF RESIDENTIAL ENERGY CONSUMPTION AND ANALYSIS OF LOCAL ECONOMIC IMPACT WITH A PERSPECTIVE ON TRADITIONAL TIMBER HOUSES IN JAPAN--A CASE STUDY OF KYOTO CITY

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Overview

In recent years, problems such as global warming and primary energy resource depletion have become increasingly serious. On the supply side, Japan has a low energy self-sufficiency ratio, depends on the Middle East region for about 90% of its crude oil (Agency for Natural Resources and Energy, METI, 2020), and is heavily dependent on Asia and Oceania for LNG and coal, and is greatly affected by international conditions. On the demand side, final energy consumption throughout Japan in 2019 will be 1.2 times higher than in 1973, of which the residential sector will be 1.8 times higher, accounting for 14% of the total (Agency for Natural Resources and Energy, METI, 2021). Energy-saving policies in the residential sector have therefore become an important issue. In addition, due to global warming countermeasures, the consumer and residential sector is required to achieve a 66% reduction in CO_2 emissions in 2030 compared to 2013, which is a very high reduction (Ministry of the Environment, 2021). Furthermore, the Building Energy Saving Law came into force in April 2021, and energy-saving measures for buildings will become more important in Japan in the future. The improvement of insulation performance is one important energy-saving measure for Japan, as 67% (MILT, 2018) of houses in Japan have no insulation and old insulation standards.

In Kyoto City, the final energy consumption of the residential and commercial sectors accounts for 56% of the 2019 average, with the household sector accounting for 25% (Regional Energy Supply and Demand Database, 2022), which is above the national average. In addition, in the four wards of central Kyoto, 30% of wooden houses (Statistics Bureau, 2008) were built before 1960 due to Kyoto being an ancient capital, and it can be expected that the number of older, uninsulated houses is above the national average. Therefore, a case study of Kyoto City, Japan is carried out in this study, with the residential sector as the research target, to determine the potential for reducing residential sector energy consumption through improved insulation and the impact of this action on the local economy.

Methods

This study uses the bottom-up method to estimate Kyoto City household sector energy consumption. First, Kyoto households are grouped into detached houses or apartment buildings by structure. Each housing group is classified according to its insulation performance in terms of the average heat-penetration ratio into no insulation, the old standard, the new standard, the next-generation standard, and ZEH (Zero-net house, hereafter ZEH), and the annual energy consumption for each house is calculated using Design builder. The annual energy consumption is multiplied by Kyoto City 2020 population, household, and housing statistics data to calculate the city-wide domestic energy consumption. In addition, the potential for reducing Kyoto City household sector energy consumption through the improvement of insulation performance by rebuilding old houses to ZEH is clarified.

The regional economic effects of energy savings from the Kyoto City household sector energy consumption reduction potential identified above and from the construction of new ZEHs in old houses will be assessed.

As an evaluation method, a regional economic cycle analysis developed by the Ministry of the Environment will be used. The regional economic cycle analysis integrates the 'input-output table' and 'regional economic calculation' for each municipality and identifies the financial flow of the regional economy and the balance of payments for regional energy. Using this analysis method can evaluate the energy balance improvement effects and regional economic ripple effects associated with the construction of ZEH through energy reduction.

Results

There is a significant reduction in energy consumption due to improved insulation performance and a high local economic benefit from the construction of ZEH. On the other hand, the financial and other burdens on the household sector associated with the improvement of insulation performance and the construction of ZEH are temporarily significant. Therefore, national and local government subsidy policies alone are not sufficient and other policy support measures must be considered to promote energy efficiency and conservation in the household sector.

Conclusions

Some traditional houses have become important cultural assets because they are tourist destinations in Kyoto City. Therefore, one important issue is to reduce local energy consumption and carbon while protecting cultural assets, and it may be possible to reduce energy bills by reducing energy consumption, generating avoidable costs, and using these costs to protect cultural assets. 2) At present, the retrofitting or improvement of the thermal insulation performance of houses cannot proceed smoothly without subsidies, and the payback period for reducing energy consumption bills alone is long. The introduction of virtual power plants and emissions trading for municipalities is expected to shorten the payback period. 3) the war in Ukraine has exacerbated Europe's energy problems in the context of deteriorating relations with Russia. Improved insulation is expected to reduce energy consumption on the demand side and alleviate the primary energy shortage problem.

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EXPLICIT DEMAND RESPONSE FOR SMALL END-USERS AND INDEPENDENT AGGREGATORS

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Accommodating an increased share of electricity generated from renewable resources on the one hand, and more active consumers on the other hand, puts pressure on the electric grids in the EU and requires the system to become more flexible. Demand-side flexibility can be cheaper than investments in the transmission or distribution networks, and including it in the system increases the reliability and resilience of the grid. In the European Union, the EU Directive 2019/944 formalizes the role of Demand Response in the electric system, and gives the opportunity for a new entity, the Independent Aggregator, to pool together the resources of multiple end-users and participate with them in the markets.
This presentation examined the progress of explicit Demand Response for small end-users across 26 EU Member States, and the status of Independent Aggregators as of the end of 2021.
Through a survey, expert interviews, and desk research, the authors found that the engagement of small end-users in explicit Demand Response has increased in most of the Member States since the previous JRC report published in 2016. Even though the first step towards making explicit Demand Response available to end-users is through their supplier, which is the case in 22 EU Member States, independent aggregation is recognized by the national legislation in 19 cases, of which in 7 countries independent aggregators of small end-users also exist and operate.

Youngho Chang, Ridwan D. Rusli, Jackson Teh

ENERGY TRANSITION AND ENERGY SECURITY IN GERMANY: A PATH TO SUSTAINABILITY AND SECURITY

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Abstract

In the course of the Ukraine-Russia war, the West's, the natural gas supply disruptions and the Ruble payment debacle, energy security has become a top priority issue for the German government. This has not been the case before. We use the 4A framework of energy security to analyze Germany's energy transition ("Energiewende") over the last 20 years. While Germany's forced build-up of renewables capacity and exit from nuclear and coal is a pioneering achievement among industrialized nations, the process has been very costly. While the acceptance of climate change policies is very high among its society and voters, affordability to energy consumers and availability of energy resources have steadily decreased in recent years. High feed-in tariffs and fuel taxes force German households to pay the highest electricity tariffs and among the highest fuel prices worldwide. Part of the country's fiscal capacity is required to support energy-intensive industries. Exit from nuclear and coal electricity production necessitates increasing natural gas imports, which in turn creates geopolitical dependency on gas producing countries like Russia, requires extensive collaboration with European neighbors and partially undermines the environmental benefits of the coal exit. Moreover, growth in renewables capacity has slowed down, hampered in part by local public resistance and increasing bureaucratic hurdles. The technological leadership of the country's multinationals and SMEs has been challenged by increasingly sophisticated and efficient competitors, for example from China. To ensure Germany's energy security the country must accelerate domestic renewables capacity and infrastructure, expand European interconnector investments and diversify its natural gas supply options.

Jeffrey Binder, Adam Cohen, Antonio Muller, Ricardo Raineri

PEACEFUL USES OF NUCLEAR ENERGY IN LESS INDUSTRIALIZED COUNTRIES: CHALLENGES, OPPORTUNITIES, AND ACCEPTANCE [3]

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While the idea of nuclear energy in many people remember some adverse events in recent human history, its peaceful uses are extensive less known and have greatly benefited society. For example, in the U.S., where nuclear power accounts for 19% of electricity, a January 2022 Pew Research Center survey found that 35% of U.S. adults say the federal government should encourage the production of nuclear power, 26% say it should discourage it, and 37% say it should neither promote nor prevent it.
The peaceful uses of nuclear energy go far beyond power generation, which today accounts for 10% of the world's total electricity supply and is the second-largest electricity source with negligible CO_2 emissions during its operation. Also, for the past 70 years, atomic energy has significantly improved human life in health, agriculture, food preservation, industry, and understanding of our world and universe..
Nuclear technology is used in the diagnosis and treatment of cancer and other diseases, radiography cameras, blood irradiators, and radio sterilization of biological tissues for the treatment of various conditions; it helps the development of scientific knowledge on the understanding and searches for a solution on environmental issues, like climate change and tracing of ecological impacts; in augmenting agricultural productivity and the elimination of food diseases, like reducing the threat of fruit flies in Latin America; and in for various industrial applications like radiography, flow measurement and leak detection in industry and mining, in dredging operations in ports, and space exploration, among many others. Not to mention the critical impact of nuclear energy programs on a solid workforce and the technological development of the countries that scale their capabilities.
On the energy side, and to achieve the deep decarbonization required to keep the average rise in global temperatures below 1.5°C, combating climate change without an increased role of nuclear power generation would be much more complicated. The IEA state that achieving the pace of CO_2 emissions reductions in line with the Paris Agreement is already a considerable challenge, as shown in the Sustainable Development Scenario. It requires significant increases in efficiency and renewable investment and an increase in nuclear power. Also, the World Nuclear Association notices that nuclear power plants, throughout their life cycle, produce about the same amount of carbon dioxide-equivalent emissions per unit of electricity as wind and one-third of the emissions per unit of electricity compared to solar.

In this work, we unveil the opportunities and challenges within less industrialized countries to developing a plan and their capabilities to take advantage of peaceful uses of nuclear energy and power generation.
Some of the critical issues/questions we address in this work are:

- How should governments interact with civil society in analyzing and evaluating the peaceful uses of nuclear energy? How should the benefits and risks of peaceful uses of nuclear energy be communicated to civil society? What role has the scientific community here?

[3] This work builds from the IAEE Webinar "Peaceful Uses of Nuclear Energy in Less Industrialized Countries: Challenges, Opportunities, and Acceptance." We thanks Ted Jones, senior director for national security and international programs at the Nuclear Energy Institute, Washington, D.C., for his contribution and participation on the webinar and inspirations for this work.
CHALLENGES, OPPORTUNITIES, AND ACCEPTANCE July 11, 2022

- What steps should countries take to build capacities to become ready to decide on building critical infrastructure for the peaceful uses of nuclear energy?
- How can IAEA and other industrialized countries support capacity building in less industrialized countries to be ready for a yes or no decision regarding nuclear energy?
- How important are the institutional framework and strong and independent regulatory and supervisory authorities in the nuclear industry for an atomic program's success and safe development?
- In many countries, institutions are weak, which can seriously threaten the success and safety of any nuclear energy program. How can governments and the international community protect from this risk by exposing the world industry to higher downside risk?
- How should we address the lack of human capital, scientists, and experts in the field?
- Is nuclear power a realistic and cost-effective solution for less industrialized countries, given significant upfront investment costs and construction periods? Is an SMRs turn-on key a solution for less industrialized countries?
- When building nuclear power infrastructure, upfront investments are significant compared to other power generation sources, such as solar or wind, which can develop. How can less developed countries secure access to finance, and what are its essential requirements?
- What are the critical characteristics of technology when deciding on the alternatives of nuclear technologies available in the market and future SMRs?
- Should nuclear power generation be evaluated as a standalone project, only looking at a long-term reliable supply of cheap energy?
- Chernobyl, Three Mile Island, and Fukushima nuclear accidents marked a stopping point in many countries on their decision to implement a peaceful use of atomic energy program. How can we assure that safety standards, in a broad sense, have been enhanced to preclude future situations like the ones there? Should the safety standards depend on organization structure development and modernized reactor design?

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Sofia Bufoli

CO_2 CAPTURE AND SEGREGATION TECHNOLOGIES

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Overview

The use of fossil fuels for energy generation has always brought most human activities to release large quantities of carbon dioxide into the atmosphere thereby irreversibly altering the climate balance of our planet. In order to reach as soon as possible the goals established in 2015 by the Paris Agreement, it is clear the need to introduce additional technologies to expand the current renewable sources landscape. These "promising technologies", as stated by the IPCC, are the Carbon Capture and Storage technologies (CCS and CCUS).
This paper focuses on the definition of the main carbon capture and storage processes and technologies, which have acquired a key role in the fight against climate change. Starting from a brief overview of the existing plants in Italy, I specifically analyzed the carbon dioxide removal strategies, with a quick mention about the ocean storage of CO2.
Finally, I compared the advantages and disadvantages of the proposed solutions, including an analysis of the costs and future developments of these technologies.

Method

First of all, I defined the main carbon capture processes that can be classified in post-combustion, pre-combustion and oxycombustion; then I analyzed the Enel S2C2 pilot plant in Brindisi, Italy and the Eni Ravenna CCS Hub and finally I described the Carbon Dioxide Removal technologies (CDR), focusing on afforestation and reforestation, Direct Air Carbon Capture and Storage (DACCS) and Bioenergy with Carbon Capture and Storage (BECCS).
The DACCS is an emergent technology which consists in capturing the CO2 directly from the air through an engineered mechanical system, which currently has a TRL equal to 6, while the BECCS solution is discussed also in the IEA 2DS scenario where it provides around 14 Gt of "negative emissions" in the period up to 2050 and in particular 1,1 $GtCO_2$ in 2050 (16% of the 6 $GtCO_2$ captured for that year).
In conclusion I mentioned the ocean storage of CO_2, a strategy that plans to take a relatively pure stream of CO_2 (previously treated and compressed) and transport it to the ocean depths where it is released becoming part of the ocean carbon cycle. Among the main strategies, some of them consist of transporting this stream of CO_2 by ship and inject it into the ocean, or deposit it directly on the seabed: in the first case the CO_2 can be released by towed pipes or transported to fixed platforms that feed CO_2 lakes which must be at depths greater than 3 km where the CO_2 is denser than sea water.

Results and conclusions

Both the IEA and the Carbon Sequestration Leadership Forum (CSLF) have asserted that, in order to reach net zero emissions by 2050, CCS technologies in 2030 and 2050 must exceed respectively 10-15 times and 100 times the current value of 40 $MtCO_2$/year, if not, the IPCC expects the cost of mitigation to increase by 138% in 2100.
Even though there are still problems to be solved (in fact, in 2019, the MIT Technology Review ranked them as first among the 10 technical challenges in the world and this mainly because of the costs and energy consumption) these technologies are short-medium term solutions that we cannot exclude from any of the CO_2 reduction scenarios consistent with the targets set by the Paris Agreement and they must assume a role of primary importance in the energy transition in order to decarbonize the industry and in particular its most energy-intensive sectors, also called "hard-to-abate".
The costs can vary within very wide ranges, depending on various factors such as CO_2 capture conditions, compression and transport conditions and the type of the storage site, however, the cost is mainly related to the CO_2 capture operations and it's affected by the concentration of CO_2 in the stream of gas sent to separation.

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VALUING MINING RESOURCE INFORMATION AND SEARCH

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Overview

Searching for exhaustible resources is one of most important challenges for energy policy. In recent years, as a decarbonization trend is prevailing world-wide, exploitation of conventional resources such as petroleum, coal, and natural gas has not been attracting attentions of businesses and policy-makers. However, development of shale gas / oil wells remains important. Methane hydrate is becoming one of the most promising exhaustible resources. In the context of carbon neutral technologies, Carbon dioxide Capture and Storage (CCS) (or Carbon dioxide Capture Utilization and Storage (CCUS)) is considered as an indispensable measure, for which storage reservoir is interpreted to be a virtual "resource" to be prepared. Thus, searching for such reservoir is understood as a type of modern resource exploitation. In this respect, the importance of exhaustible resource exploration remains unchanged regardless of the change of the social trend.

It is sure that technologies of resource exploration have become sophisticated more than ever before while the procedure remains unchanged, too. That is, resources under the ground or under the sea are identified, located, and excavated. Thanks to the recent development of sensing, information and data processing technologies, processes of identification of the resource as well as determination of its location are much more efficient and accurate than the time of conventional petroleum and gas. On the other hand, the process of excavation is more physical than informatics, so may have benefited less from recent technology development than the other processes. As a result, there are found many cases where the existence of the resource there is determined, but the cost for excavation is uncertain and most likely expected to be high, and thus the development cannot be launched. Methane hydrate is a typical example of such situation. CCS/CCUS may also be same. Note that for Japan, it is scientifically reported that Japan has a plenty of methane hydrate reservoir under the sea alongside Japan islands' coast. As is known, Japan has virtually no oil and gas reservoirs on its land, and thus, the possibility of methane hydrate availability can be an ultimate solution to national energy security. However, the biggest problem is uncertain cost.

The purpose of this study is to develop a model of optimal strategy for searching for resources in such a modern context of resource exploitation, in which we know the resource is surely there under the ground or under the sea, but due to the uncertainty regarding the exact location and cost to get to the location, we hesitate to launch the search. The analysis of the model helps clarify the values regarding the resource search, in particular, the value of information that can be provided by state-of-the-art sensing and data processing technologies.

Methods

To make our mathematical formulation easier, we consider a situation where we drill a tunnel in a horizontal direction instead of digging a hole vertically. Also, assume that drilling is discrete steps rather than continuous. It can start with the first step of drilling and keep going from left to right. The number of steps of drilling is finite, up to N steps. Assume that it is sure that there exists the object of drilling. Let us call it treasure. The treasure can be found when we taken-th step of drilling, butnis unknown until it is actually found. More specifically, while we are sure that we can obtain the treasure sometime, to do so, we need to keep taking steps of drilling until we find it. We stop drilling once we find the treasure, but we can stop anytime and give up to find it.

Let us assume the following:
- The value of the treasure is h dollars.
- To take a step of drilling, the cost of c dollars is needed. Doing nothing, instead, costs nothing.
- It is assumed that $h > c$.
- Discounting regarding time preference is neglected.
- Total cost to drill to the end, taking the final N-th step, is larger than the treasure's value, that is, $Nc > h$.

Results

We can make a variety of this modeling with various settings. A simplest one is to assume that we are a risk-neutral decision-maker. Let $V_N(n)$ denote the value of the series of untaken-steps to go. It is formulated in a recursive manner as follows:

$$V_N(n) = \max\ \{-(n-1)c, p_N(n)(h - nc) + (1 - p_N(n))V_N(n+1)\ \}$$

where $p_N(n) = \frac{1}{N-(n-1)}$

The following proposition holds:

Proposition 1:
Assume the following inequality: $h > \frac{N+1}{2}c$. Then, the solution for $V_N(n)$ *is obtained as the difference between these two, namely:*

$V_N(\mathrm{n}) = h - \frac{N+n}{2}c$
(Proof omitted)
An interesting question would be about the value of information regarding the place of the treasure. Assume that there is a state-of-the-art sensing technology that can tell with perfect accuracy where the treasure is in the series of steps. Let $V_N^c(\mathrm{n})$ denote the value of the series of untaken-steps to go when the perfect sensing technology is available. Then, the following proposition holds.

Proposition 2:
The value of information, $V_N^c(\mathrm{n}) - V_N(\mathrm{n})$ *at every step of drilling is non-negative.*
(Proof omitted)

Analysis can be extended in various ways, including risk-averse case, sensitivity analysis, etc

Conclusions

The model presented here is a very simple one, but it can capture a key aspect of resource exploitation that is common to many modern energy and climate policy measures. The emphasis is upon the insight to the role of technologies such as sensing and data processing for methane hydrate, CCUS, etc, which helps for valuation of those technologies.

Milien Dhorne, Marc Baudry

TOWARDS CARBON NEUTRALITY AND ENERGY INDEPENDENCE IN EUROPE: CAN NEW STORAGE AND RENEWABLES PUSH FOSSIL FUELS OUT?

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Overview

Variable and renewable energy (VRE) sources lie at the core of the European energy decarbonating and independence strategy. A larger share of renewable generation requires flexibility options to cope with production fluctuations. In this context, energy storage is acknowledged as a promising solution to cope with intermittency but its contribution to the power system is still uncertain. We investigate in this paper the development of energy storage solutions as dispatchable assets to compete with existing and future fossil fuel power plants. We present a theoretical model showing that storage can increase or decrease CO_2 emissions but may support the development of solar and wind. We confirm these results with a stochastic competitive equilibrium framework, calibrated on the current Western European power system, to derive the market value of new storage technologies and their impact on the power system. We estimate the long-term equilibrium of flexibility and renewable capacities under a coal phase-out policy. We subsequently analyze the CO_2 emissions and the fossil fuel consumption. We find evidence that the development of storage, stationary or vehicle-to-grid, is delayed by the competitive advantage of new gas power plants. We underline that storage provides moderate beneficial effect on CO_2 emissions or energy independence. However, our results suggest VRE development could in the long term be accelerated by storage, making a case for a smart design of transition policies.

Methods

As recent literature showed the role of storage was ambiguous, we first introduce a two-period stylized theoretical model. We account for two fossil generation technologies, baseload and peaking units, and two renewable sources, solar and wind. We demonstrate that because of efficiency, dispatch and investments effects, storage does not necessarily reduce CO_2 emissions in the short and long term. Interestingly, storage support the development of the most intermittent VRE technology, solar, but has unequivocal impacts on wind energy. We therefore raise awareness on the necessary conditions for storage to sustain the energy transition and highlight the importance of empirically assess the situation in Europe.

To quantify the energy-only market-based development potential of promising storage technologies and their impact on the price structure, we propose an empirical model representing the current and future Western European electricity power system. We simulate an interconnected version of the European grid until 2040, with 10 of the most important countries for comparison. Our framework relies on stochastic optimization methods to better suit and handle the intermittent nature of renewable-based power systems. On top of providing a probabilistic and frequency analysis, such method renders robust results for the consideration of VRE and storage economic viability, to depict an accurate situation of the near future.

We construct scenarios by sampling weekly historical data, similarly to a Monte-Carlo approach, which aim at faithfully representing the fundamental discrepancies between seasons and the various states of the power system. Secondly, we derive long-term market equilibria, under efficient hypothesis, by minimizing the total cost of the European power system by allowing investments in new storage and gas capacities. Solving the two-stage problem – capacity expansion and operation - involves a multi-cut algorithm based on Benders decomposition. Our model is calibrated on the Western European power system, with fine modelling of the existing flexibility park, including pumped-hydro storage and nuclear availability. Our work relies on an exhaustive, heterogeneous, and unit-level representation of existing power plants.

Results

We first derive from our methodology estimates of the long-term equilibria of flexibility capacities under different environmental policies. In particular, we investigate the possibility of a complete coal phase-out in Western Europe and its consequences on flexibility needs. We find evidence that the development of storage is moderate and located in a few countries of interest. Overall, intermittency stemming from ambitious renewables targets is largely mitigated by the predominant contribution of new gas facilities and, to a lesser extent, of V2G, as it accounts for the main share of the new storage capacity. New gas facilities remain strong competitors to stationary storage indeed and completely preclude it from the market. Moreover, the V2G market size only amounts to 8% of the electric fleet. In case of new gas moratorium, V2G ensures most of the flexibility needs before 2030 but stationary storage (Li-ion batteries and power-to-hydrogen) becomes cost-optimal in Northern countries (Germany, the Netherlands and the United- Kingdom) and amounts to 30 GW by 2040.

Secondly, we analyze incremental investments due to the presence of storage on the wholesale market and their distributions among renewable firms. We highlight a positive effect of storage on solar and offshore wind, but no effect on onshore wind. Remarkably, V2G tend to better suit solar production while stationary storage copes with offshore fluctuations. These findings confirm the theoretical results.

Finally, we characterize to what extent new storage reduces fossil fuel consumption and CO_2 emissions. A pathway relying on new gas facilities prevents approximately one year of emissions by 2040, due to an early and steady reduction of coal consumption. It however increases the energy dependence towards fossil gas. Freezing new gas investments increases CO_2 in the short term, but by supporting investments in VRE, ends up being more promising for the 2040-2050 period. These metrics are of utmost importance to apprehend the possible path towards energy independence and carbon neutrality, as well as the way to reinforce renewable investments. Our results indicate that additional value is to be found in supporting storage development at the expenses of new gas.

Conclusions

In the recent years, storage has regularly been presented as the last piece to solve the energy transition and independence dilemma by complementing renewable sources. We bring evidence that market-based storage development remains uncertain without additional policies. Reaching the critical market size for storage will require stronger energy commitments and a concerted reflection of the role of fossil gas in the transition. As the main takeaway, renewable expansion will sooner or later face dropping market revenues, that storage could alleviate but not gas power plants. By supporting low prices and reducing volatility, storage sets up a more sustainable environment for renewable development. Additional value is also to be found in the reduction of fossil fuel consumption and CO_2 emissions. Our study consequently makes the case for an adequate and smart design of support policies that integrates the transfers storage operates between market firms, and the non-market welfare improving services it provides.

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Diyun Huang and Geert Deconinck

COLLABORATIVE GOVERNANCE FOR EUROPEAN CROSS BORDER NETWORK INVESTMENTS – BUILDING INCLUSIVE INSTITUTIONS WITH USER VOTING APPROACH

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Reconciling centralised and decentralised governance elements to break the gridlock from fragmented national decision making structure and accommodate future technology shift

Current pan European transmission network planning and investment mechanism comes from the requirements of Third Energy Package. National TSOs, are envisioned in the Third Energy package to play a central role in the European electricity network investment and act as the main planners, operators and investors for cross-border network. Countries participate in the pan European cross-border network investments by sharing the same planning methodology and investment process. However, energy mix determination, network investment approval and remuneration regulation are the responsibilities of national authorities. Incentives for stakeholders at national or local level are not always aligned for cross-border coordination. For instance, the consumers in exporting countries will face higher price with increasing energy export. Thus national regulatory authorities in the exporting country may hesitate to approve large capacity interconnections that leads to price hike for their consumers. To break the gridlock from current fragmented national decision making structure in interconnection investments, this research proposes collaborative governance for cross- border investments that centres around the idea to involve directly affected users to vote for potential projects. The governance structure consists of two interwoven elements: i) institutions; 2) network investment process and methodology. The digital infrastructure of the user voting system is proposed to be backed by blockchain technology.

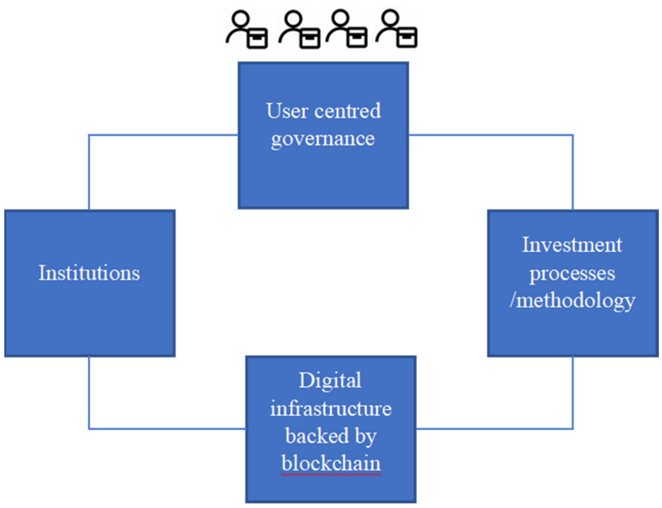

Figure 1 - Main components of user centred governance

Facing fundamental technology shift, decentralised and centralised elements should be reconciled in future transmission investments. Traditionally, the electricity sectors are segmented into sectors such as generation, transmission, distribution, end consumers. Technology shift plays an important role in challenging the effectiveness of current transmission network governance.

Mobility, heating transition and digitalization will not only increase new electricity demand substantially, but also bring device controllability, trading possibility for consumers and form new contractual relationship between grid and consumers. New technical and commercial characteristics blur the boundaries between the sectors in electricity industry. The big wired centred power system and its institution designs need a reshuffle. A poly centric governance structure is envisioned for market operation and interconnection investments with stakeholders involved from subnational, national and regional levels.

New governance layers, user voting approach and joint regulated asset base

New governance layers are proposed to be included in the cross-border cooperation for network investments, in addition to the national institutions. At subnational governance level, involvement from cities and states in the energy governance allows the local policy flexibility and innovation. Cities and states that are often responsible for making local mobility and housing decarbonization policies will play a critical role in the next phase of energy transition. Their input is proposed to be an essential part of the scenario making process. These inputs are aggregated by national planners or energy authorities to form a more detailed National Energy and Climate Plan (NECP). At supranational level, new regional institutions such as independent system operator, regional planner and regional energy committee are envisioned with functions involved in cross-border electricity market and network investments. As an important component of collaborative governance, regional energy committee that has a fair representation of different sectors serves as a user cooperative, a common supervisory and dispute resolution body.

In the cross-border network investment process, user voting approach is proposed as a novel mechanism complemented by administrative project approval. In the European context, it contributes to streamlining process for cross-border network expansion that democratise the project selection to prioritize user preference. Three main elements are proposed for cross-border cooperation between generation and transmission investments: 1) using national energy and climate plan that includes subnational level energy development plans for scenario building; 2) coordinating grid investment and renewable auctions; 3) linking plan input assumptions with tariff setting in the joint regional RAB. The first two measures aim to improve the input information accuracy and the investment accountability from the network design and planning aspect. The network cost allocation envisioned in these investments follows the benefit pays principle. Electric usage of the new network is calculated to be the proxy of project benefit. Users or grid user group identified to be most impacted are invited to vote for potential projects. For users without sufficient analytical capability, they can also delegate their voting power to its representative in regional committee. In essence, users indirectly or directly get involved in the scenario data collection, project analysis and network investment decision making.

A joint regulated asset base (RAB) for user approved projects is proposed as a long-term commitment tool for investors against regulatory risks across borders. Setting rate of return according to risk patterns in different phases of transmission projects can give investment incentives while lowering financing cost over long-term. The efficiency between generation and transmission network investment coordination and transmission investment accountability is held by differentiating tariff for non-compliance of network planning scenario input. Collectively, users have influence on the market rule making that is determinant for network utilization rate. Users are effectively the owners of the joint asset base, co-direct the investment trend and co-govern the asset remuneration. Blockchain with its distributed ledgers stored all over network, facilitates trust building between previously unknown institutions. It is proposed to be the underlying digital infrastructure for a smart platform that implements envisioned collaborative governance in cross-border transmission network investments.

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IMPACT OF E-MOBILITY ON DISTRIBUTION SYSTEMS: THE ROLE OF SMART TARIFFS FOR VEHICLE GRID INTEGRATION

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Overview

Advanced economies and emerging countries are developing net-zero emissions roadmaps to reach carbon neutrality in the mid of this century. They are supported by several international agencies and organizations, which are building different scenarios to reach globally this goal, with all the underlying challenges. In recent times, with the energy crisis triggered by the conflict in Eastern Europe, it appears evident that decarbonization of our economies is also beneficial for energy security, with renewable sources that can be freely leveraged to produce energy decreasing the dependency on fossil fuels (often concentrated in few areas). In last years the electricity sector has been a forerunner in the decarbonization through RES, especially in EU where the CO_2 emissions in this segment decreased by almost 50% in comparison with 1990. However, other sectors lag behind in the decarbonization path, such as transportation: indeed, in the EU transport was the only sector to register an increase of CO_2 emissions (+25%) in 2019 with respect to 1990. Therefore, significant efforts shall be focused on this segment, where according to IEA emissions shall decrease from 2020 levels by 20% in 2030 to be on track to reach carbon neutrality in 2050. One of the most relevant solutions for the decarbonization of transport sector is represented by e- mobility, which can leverage on higher efficiencies compared to internal combustion engines and on the widespread diffusion of renewable power plants that can supply cleaner electricity to the vehicles. The diffusion of alternative vehicles will also be supported by normative initiatives, such as the EU proposal to ban the sale of new fossil fuel cars from 2035, which has been endorsed by the European Parliament.
The transformation of the transport sector, which will be to a larger extent covered through electrification, will have a non- negligible impact on the power system and their infrastructure: alongside the electrification of end-uses which will increase the power consumption in the next decades, a relevant amount of electricity shall be supplied to vehicles, leading to needs for replacement and upgrade of power infrastructure. With regard to e-mobility the major challenges are related to the power component, due to the possibility of having multiple charging events concentrated close to the current power peaks (e.g. in the evening), leading to the substitution of power components such as transformers, feeders and cables. The possibility to leverage on smart charging mechanisms, and in the first place to smart tariff schemes aiming to flatten the demand profile could deliver significant benefits in a systemic perspective.

Methods

CESI developed a methodology and a specific tool to estimate the additional investments needed in a distribution system due to the presence of electric vehicles, and the related savings that can be obtained in case of an improved tariff scheme. In the specific case, the comparison has been done between a flat tariff (a unique price for the entire day) and a Time of Use tariff (enabling to have a lower price during the night, period characterized by a lower electricity demand).
The analysis has been divided in two main tasks: (i) Assessment of the demand of electric vehicles, (ii) Quantification of investments in the distribution grid.
For the first task, CESI developed a proper tool to estimate the demand of e-mobility in a certain area, which consider a series of factors, including:

- Type of vehicles (e.g. passenger cars, light duty vehicles, heavy duty vehicles, bus, etc.).
- Charging points, with differentiation based on nominal power and technology (e.g. unmanaged charging, V1G or V2G).
- Charging behavior (i.e. timing and duration of charging events).
- Charging location, considering habits of different types of users.

- Use of the vehicle (i.e. travelled distance).
- Share of electrification, with the possibility to assess different scenarios of e-mobility penetration.

The type of tariff implemented is also considered in the tool, with the flat tariff that does not affect the time of the day a user will recharge its vehicle, while the ToU tariff incentivizes the driver to recharge the EV when the price is lower. Considering those factors, it is possible to calculate the demand profile associated to EVs with an hourly discretization.
In the second task, according to the information available on the distribution components, a proper classification of the different assets with respect to their load factor (i.e., the ratio between the maximum power and the nominal power) shall be carried out. This activity could be done by splitting the components in classes according to their load factors (e.g., 10% of thetransformers present a load factor of 0.9, 20% have a load factor of 0.8, etc.). Subsequently, the conventional load (i.e., the electricity demand excluding e-mobility) is calculated considering the rate of load growth foreseen for the year in the targeted scenario. Through a proper distribution of the electricity demand on the different underlying distribution assets is possible to calculate the new load factors associated to the increase of the conventional load. After setting a proper threshold for the load factor above which the component shall be substituted, it is possible to calculate the investments needed related to the increase of the conventional load. This calculation shall rely upon a solid base of costs related to the specific components and to the area object of the study. Finally, adding the contribution of e-mobility to the electricity demand is possible to identify the eventual new peak power and repeat the previous steps for calculating the new investments needed. In this way it will be possible to clearly identify and quantify the additional investments needed in the distribution grid exclusively caused by e- mobility and compare the cases between flat and smart tariff.

Results

According to the analysis made, which are dependent on the context in terms of load profile and future growth, uptake of electric vehicles and ageing of distribution components, the introduction of a ToU tariff could lead to savings in investments even greater than 50%. However, the possibility to defer grid investments to this extent depends also on the willingness of the users to adopt the tariff scheme and the availability of technologies that could enable a proper programming of the charging events. On the other side, ToU tariffs could represent the first and easiest step for the integration of EVs in the network, suggesting the presence of a relevant potential for investment savings through more complex smart charging technologies (e.g. V1G, V2G) and the possibility to proactively use EVs as a useful resource for the power system.

Conclusions

After a brief recall of the decarbonization objectives set by the EU with special focus on transport sector, the paper will provide an overview of the tariffs schemes adopted in some key countries highlighting pros and cons for e-mobility, considering the specific environment of Italy. Thereafter, the methodology adopted to minimize the investment effort in distribution grids leveraging on tariff schemes will be described in detail. Finally, the possible benefits arising from appropriate tariff schemes in terms of avoided or deferred investments will be discussed.

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FEASIBILITY STUDY FOR THE CONSTRUCTION OF A DEMONSTRATION PLANT FOR THE PRODUCTION OF E-FUELS

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Overview

E-fuels are synthetic liquid or gaseous fuels, produced through the combination of CO2 and H2 from renewable sources to produce renewable fuels. The overall effect of the e-fuel production process is to transform renewable electricity and CO2 into chemical energy in the form of climate-friendly fuels, which can be used as energy carriers (Dena, 2019) (Fratalocchi, 2020). The e-fuels characteristics are very similar to those of the corresponding traditional ones and this makes them compatible both with the existing transport, distribution and storage infrastructure, and with the current end use systems. (Frontier Economics, 2018).
The production of e-fuels is mainly based on the synthesis processes of green hydrogen produced by the electrolysis of water (using renewable energy sources) and carbon dioxide (CO_2) which can be captured from a concentrated source (fumes of an industrial site), from the air (through Direct Air Capture, DAC solutions) or by exploiting the CO2 of biogenic origin deriving from the production of biofuels. E-fuels can be considered climate-neutral fuels since the production process don't release incremental CO2 and, thanks to their compatibility with internal combustion engines, they can be used to power road vehicles, airplanes and ships, helping to decarbonise the transport sector.

Methods

The project presented in this paper was commissioned to Innovhub SSI by unem to define the technical-economic parameters of a demonstrative pilot plant, able to produce sufficient quantities of e-fuels (Fischer-Tropsch) to carry out performance tests, as well as to evaluate the technical and economic potential for a future development in the Italian energy landscape.
The work officially began in February 2021 thanks to the collaboration between Innovhub SSI and the Politecnico di Milano. In particular:
- the GECOS Group of the Department of Energy carried out the technical-economic analysis of e-fuel production plants, defined the process specifications of the main components and estimated the investment and operating costs of the plant;
- the Energy & Strategy Group of the Department of Management Engineering was entrusted with the task of identifying and characterizing the economic variables associated with the construction of e-fuels production plants in Italy and to demonstrate the feasibility of the project.

Results

The technical-economic analysis carried out in this project confirms that the production of e-fuels is technically feasible using existing and relatively consolidated technologies. Nevertheless, the expected energy yields, meaning by this the percentage of electricity of renewable origin transformed into chemical energy stored in the e-fuel produced, are relatively modest and the predicted production costs are significantly higher than those of conventional fossil fuels. These criticalities could be balanced by the much lower need for huge infrastructure investments to ensure energy supply to the various transport sectors, compared to a full-electrification scenario. Furthermore, e-fuels have the main advantage of being usable in sectors that are difficult to electrify (air and sea transport) maintaining the existing vehicle fleet and, therefore, would allow a more rapid decarbonisation of those sectors without having to achieve a complete replacement of the fleets.

Conclusions

E-fuels have an energy density much higher than that of batteries and therefore allow for the reduction of greenhouse gas emissions in transport, while preserving the current circulating fleet of vehicles.

It is also possible to continue to use the transport, distribution and sales infrastructures nowadays in use for current liquid fuels as they are also perfectly compatible with e-fuels.
The production of e-fuels also represents an important solution to the problem of long-term storage of energy produced from intermittent renewable sources. In Europe, the production of wind and photovoltaic energy is constantly increasing but is characterized by a strong intermittence in relation to weather conditions, based on daily, weekly and monthly variations. The amount of renewable electricity produced in excess of the grid demand can be efficiently stored for seconds, hours, days and weeks (e.g. in batteries), but convenient solutions for long-term storage are not yet available (O`Connell et. Al., 2019). Thanks to their high energy density, e-fuels can balance the intermittency of renewable electricity production (in large-scale stationary systems as well as in mobile tanks), integrating the traditional energy storage systems (Blanco and Faaij, 2018).
Nevertheless, since the overall efficiency of the process is a fundamental parameter to judge its validity and to guarantee its long-term sustainability in this study, we tried to select only those process and plant solutions which gave the best performance in terms of energy efficiency, reduction of CO2 emissions and minimization of production costs.

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STUDY OF ENERGY INDEPENDENCE OF EUROPEAN COUNTRIES IN THE CONTEXT OF NEW GLOBAL SECURITY CHALLENGES

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Overview

The energy independence of the country is a fundamental component of its sovereignty. It determines the independence of one country from the energy resources of others. The European Union imports 90% of the gas it consumes. Until recently, the share of the Russian Federation in this import was 45%. This is about 140 billion cubic meters of natural gas, of which 15 billion cubic meters were supplied in liquefied form. The EU also imports about 25% of oil and oil products from Russia and 45% of coal.
A sharp rise in energy prices began in early 2021, during a heated dispute over the commissioning of the Nord Stream 2 gas pipeline. With the beginning of the full-scale Russian invasion of Ukraine on February 24, 2022, the next jump in prices took place. This rise culminated on March 7, when gas prices topped $3.800 per 1.000 cubic meters as a result of Russian threats to cut off gas supplies to Europe as a countersanction. On average, over the past six months, the price of gas has increased by 40% compared to December 2021. At the same time, the United States has banned the import of Russian energy carriers, but the European Union is not yet ready for a complete rejection of Russian energy carriers.
The war in Ukraine exacerbated the problems in the energy market and necessitated an immediate review of the strategy for the energy independence of the EU providing. Our paper examines the prerequisites for building such strategies and explores the possibilities of developing energy systems in Europe, given the significant reduction in dependence on Russian energy.
Various world organizations are engaged in research in the field of energy security and independence. At the National Technical University of Ukraine "Igor Sikorsky Kyiv Polytechnic Institute" we are also engaged in researching energy development strategies on the European continent and globally based on the application of intelligent data mining and system analysis. In order to monitor and comparative analysis of the energy independence state of different countries, a methodology (metric) for quantitative measurement of this indicator has been developed. It summarizes the characteristics of the country's energy system by such groups of indicators as the country's potential for access to fuel and energy resources; the balance between energy production and consumption; the ability of the country's energy system to develop and transition to renewable energy and energy efficiency. An integral indicator that aggregates the quantitative values of these groups of indicators is the Energy Freedom Index.

Methods

In [1] we proposed a method of a quantitative assessment of the state of energy systems of countries in the form of an integrated index Energy Freedom Index. The index is built using the methodology of constructing composite indicators [2].
The conditions of functioning of the energy sector of the studied countries have significant differences. To perform an effective analysis, we use data mining techniques including comparative, correlation and regression analysis. Also, the groups (clusters) of countries were built using the k-means method according to the Energy Freedom Index, so that each subset consists of similar countries.

Results

This situation shows that the countries of the European Union have been implementing the strategy of energy independence too slowly, probably because they saw an economic advantage in the use of

imported Russian fuel resources. For each country, the ability to abandon Russian fossil fuels is determined by their energy systems' structure and state of development.
The proposed Energy Freedom Index of the country (*Ief*) aggregates the outlined components and is calculated on the basis of three separate sub-indices, each of which can be the object of independent analysis, namely: sub-index of energy potential, sub-index of energy balance, and sub-index of energy development. Since the factors whose influence is reflected in the outlined sub-indices (energy potential, balance and development) strengthen or weaken each other, the integrated Energy Freedom Index is defined as the product of three sub-indices. The Energy Freedom Index was calculated for 2000-2020 and 141 countries.
The conditions of functioning of the energy sector of the studied countries have significant differences. To perform an effective comparative analysis, we divide a group of countries into subsets (clusters) according to the Energy Freedom Index so that each subset consists of similar countries. Based on the calculated data of the Energy Freedom Index, the studied countries were clustered according to this indicator using the k-means method. The results of clustering in six clusters are as follows.
Cluster 1. High value of Energy Freedom Index. According to the results of the study, the countries that demonstrated the highest level of energy freedom included Angola, Congo, Mongolia, Norway, Azerbaijan, Australia, Nigeria, Saudi Arabia, Mozambique, United Arab Emirates, Colombia, Oman, Algeria, Kazakhstan, Russian Federation, Turkmenistan, Venezuela, Bolivia, Indonesia, Ecuador, Canada, Iran, Cameroon, Ghana, Laos, Uzbekistan, Malaysia, USA.
Cluster 2. Average value of Energy Freedom Index. Countries with an average level of energy independence include Bhutan, South Africa, Paraguay, Peru, Brazil, and Argentina. The main criteria for grouping countries and assigning them to the second cluster is the balance of production and consumption of all types of electricity.
Cluster 3. Sufficient value of Energy Freedom Index. In the countries of the third cluster with a sufficient level of energy independence should be distinguished Egypt, Ivory Coast (Côte d'Ivoire), Tajikistan, China, Yemen, Niger, Iceland, Vietnam, New Zealand, Serbia, Romania, Bulgaria, Botswana, Poland, Albania, Uruguay, Czech Republic, Belize, India, Switzerland, and Pakistan. Ukraine also fell into this group.
Cluster 4. Low value of Energy Freedom Index. Rising risks of unbalanced use of energy resources and insufficient development of the energy sector have led to a decrease in the level of energy independence of these countries: France, Slovenia, Thailand, Malawi, Costa Rica, Finland, Syria, Afghanistan, Tanzania, North Macedonia, Netherlands, Israel, Ethiopia, Croatia, Austria, Hungary, Uganda, Germany, Slovakia, Philippines, Ireland, Georgia, and Tunisia.
Cluster 5. Critical value of Energy Freedom Index. The countries of the cluster include both developing and developed countries: Armenia, Honduras, Eswatini, Lesotho, Turkey, Guatemala, Chile, Spain, Greece, Nepal, Nicaragua, Kenya, Portugal, Mali, El Salvador, Belgium, Italy, Cambodia, Latvia, Estonia, CAR, Panama, Rwanda, Madagascar, Sri Lanka, Fiji, Japan, Guinea, Namibia, South Korea, Barbados, and Sierra Leone.
Cluster 6. Catastrophic value of Energy Freedom Index. Deficit of own energy resources, unbalanced development of the energy sector, in particular, low level of diversification of energy resources, led to a critically low level of energy independence in countries such as Lithuania, Belarus, Morocco, Dominican Republic, Mauritius, Jordan, Cape Verde, Senegal, Jamaica, Cyprus, Luxembourg, Burkina Faso, Moldova, Malta, Singapore, Lebanon, Guyana, Gambia, Seychelles, Togo, and Benin.
Energy Freedom Index, integrated for the whole period, allowed to establish similar factors, conditions and features of energy systems, which ensured countries to achieve the results defined in the study. In the leading countries, the high index was mostly provided by the high values of the energy balance sub-index and the energy development sub-index. This shows that balancing the use of energy for the needs of the economy with the ability to produce the necessary gross national product, as well as the ability to use renewable energy sources and increase energy efficiency are more important components in achieving energy independence than access to fossil fuels in energy potential.
In 2021, there have been significant changes in the EU economy and the electricity market in particular. The EU was hit by an energy crisis. On the one hand, the post-pandemic economic recovery has increased natural gas consumption – in the EU as a whole by 4% compared to 2020.

Quarterly production became lower than in the period 2015-2019 [3]. This showed that the reduction in domestic gas production in the EU is a long-term trend.
The full-scale Russian invasion of Ukraine at the end of February 2022 significantly affected the situation in the European energy market. Prices have risen unprecedentedly and consumption has fallen. According to the plan, by the end of 2022 it is expected to reduce EU demand for Russian gas by 100 billion cubic meters or two-thirds of the total [4]. The most difficult thing is to refuse to import Russian gas to its largest consumers – Germany, Italy and France. However, France has said it is ready to support an embargo on Russian oil and gas imports. Other countries, including Germany, are not ready to give up supplies from Russia.
For further research, a pairwise correlation analysis was conducted to determine the relationship between the Energy Freedom Index, which is a generalized measure of the country's ability to embargo, and the share of imports of Russian energy in its total consumption, which is a measure of dependence on Russia.
Based on the results of the analysis, it is possible to group countries on the basis of the relationship between their energy freedom and the share of Russian energy imports as:

- countries with a high and medium density of the inverse relationship between their energy freedom and the share of imports of Russian energy (Poland, Estonia, Germany, Denmark, Romania, the Netherlands, the Czech Republic, Cyprus and Spain);
- countries with a low level of direct and inverse relationship between their energy freedom and the share of imports of Russian energy (Latvia, Slovakia, Hungary, Slovenia, Austria, Belgium, Lithuania);
- countries for which the relationship between their energy freedom and the share of imports of Russian energy has not been established (Croatia, France, Malta, Finland);
- countries with a high and medium density of direct relationship between their energy freedom and the share of imports of Russian energy (Greece, Luxembourg, Portugal, Italy, Sweden and Ireland).

Among the established groups of countries, only the first can show that for these countries, increasing dependence on energy imports from Russia may reduce the level of their energy independence and vice versa. The rest of the groups have either a weak and no correlation between variables, or results that contradict the hypothesis about the nature of the relationship between the energy freedom of countries and energy imports from Russia. Thus, the correlation analysis does not allow to clearly identify patterns of dependence of countries on energy imports from Russia and to determine which of them are willing to abandon such imports and take measures to reduce this dependence.

Conclusions

Analysis of the energy independence of the European Union, after the Russian military intervention in Ukraine, showed significant negative consequences. Inflexible and multi-vector energy policy of industrialized EU countries, and their underutilization of energy potential, including the development of renewable energy, and low energy balance have led to import dependence on one energy supplier, and limited opportunities to use their own energy sources. The consequence of such an imbalance is the economic dependence of countries with developed economies on the Russian Federation, which has a predominantly raw-materials-based economy.

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Costis Stambolis

ENERGY SECURITY ISSUES IN SE EUROPE

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The energy security issues confronting SE Europe are examined through IENE's insight as presented in its seminal study " SE Europe Energy Outlook 2021/2022",which was published by the Institute in March 2022 (see link) This latest "Outlook" report offers a critical assessment of the current status of the energy sector and the energy market in SE Europe. The defined geographical area, which is covered by the IENE (see www.iene.eu) includes the Western Balkans, Croatia,Slovenia,Hungary, Greece,Bulgaria,Romania, Cyprus,Turkey and Israel.

The "Outlook" brings together the latest available knowledge on energy developments in the region and also,provides comprehensive data on energy demand and supply and the energy mix of the various countries and the region as a whole. It reviews the major energy projects and the pursued energy policies in the region but also recognises prevailing trends and provides information on estimates and projections.Furthermore, the " Outlook" takes into consideration the economic and political background of SE Europe and analyses the dynamics of the regional integration process from an energy perspective.

Energy Security emerges as one of the major, if not the key, policy issue which concerns the current energy situation in the broader region. Following a careful analysis of the energy security angle proposals are tabled on how energy security can be strengthened. The need to lessen the various countries's energy dependence by increasing indigenous energy production, both from conventional,nuclear and renewable energy sources, is considered of paramount importance. It should be pointed out that most countries in the SEE region are heavily dependent on oil and gas imports.

In addition there is a need to diversify energy supply routes in SE Europe, especially those concerning natural gas, and considerable progress in this direction has already been made with new gas interconnectors in place or under development and new LNG terminals under construction. On account of plans under way and specific projects being pursued the overall impression is that energy security is gradually being improved but it will take a lot more effort and consistent work to be able to harness the region from the anomalies of energy supply, which become evident in the event of major geopolitical upheavals as is the case today with the ongoing war in Ukraine. The detailed presentation can be seen here.

(https://www.iene.eu//articlefiles/inline/stambolis%20-%207th%20%20aiee%20energy%20symposium%20-%20current%20and%20future%20challenges%20to%20energy%20security%2015-12-2022.pdf:

Umut Ergezer

THE SOUTH EAST EUROPE (SEE) 2030 STRATEGY

Umut Ergezer, SEE2030 Coordinator of RCC)

The South East Europe (SEE) 2030 Strategy is a joint call for action by all 13 South East European Co-operation Process (SEECP) participants, adopted by the SEE leaders at the SEECP Summit held in June 2021 in Antalya.SEE 2030 Strategy seeks to promote and advance the implementation of United Nations Sustainable Development Goals (UN SDGs) within the SEE region across the three dimensions of sustainable development:

1) Prosperity
2) People
3) Peace and Partnerships

The objective of the Strategy is to reach regionally sustainable economic growth, reduce poverty and inequality, improve social inclusion, empower women, decelerate depopulation, enhance the overall quality of life for citizens and accelerate the green and digital transition, without disrupting competitiveness and private sector development.

Guided by the principles of all-inclusiveness, green and digital transformation, the SEE 2030 Strategy is fully in line with global development trajectories and European Union (EU) priorities, thereby also serving to promote Euro-Atlantic integration. The core principle of action in this Strategy is to support designing regional policies for the whole of society and to prioritise activities to leave no one behind.

Adopting the SEE 2030 Strategy at the SEECP Summit in 2019, the highest political level in SEE, the thirteen SEE participants undertook the commitment to reach 45 different socio-economic targets in line with the UN SDGs and Agenda 2030.The SEE 2030 Strategy considers regional inclusive cooperation as key to the success in reaching its targets jointly committed by the SEE participants. Transnational, global, and regional challenges become increasingly complex and intertwined, proven by the war in Ukraine and its percussions threatening the overall sustainability of security, economic and financial architecture in Europe. A holistic consideration of those challenges makes clear that they pose a growing threat to sustainable development that no single economy in SEE can tackle alone. The SEE 2030 Strategy therefore aims to serve as an inclusive regional strategic initiative for dialogue and cooperation on sustainable development issues with a direct impact on socio-economic development agendas of the SEE economies.

The current economic crises triggered by the war in Ukraine hiked the prices of energy and food globally. The future prices of these commodities will continue being as high as their present levels and no significant decrease is forecasted. Under such situation, increasing in the number of population groups living below or at the level of poverty and further deterioration of the quality of life in South East Europe can be expected. Inclusive growth as the main monitoring outline of the SEE economies SDGs' performance need to be promoted. In this regard, financing instruments of the inclusive growth agenda should include private sector investments, higher SDGs responsive national budget and official development assistances.

Mihai Sănduleac, Horia Necula
SECURITY AND RESILIENCE IN THE ENERGY SECTOR

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When speaking about energy resilience, there are at least two categories, to be applied for the electricity domain: a) Resilience of the main power system (public electrical network) and b) Resilience of the end user.

The resilience of the main power system applies to large (bulk) production units, to transport and system operation (TSOs) and to distribution of electrical energy (DSOs). In this case, all segments of the chain need to be operational, otherwise the final customer is not supplied. An advantage is that this is eased by the meshed network which allows re-routing of the energy flux, to maintain energy supply if some of the elements become non-operational.

Resilience of the end user is an emergent type of resilience, which has been not largely considered in the past. It represents the resilience of the energy entities of the future: especially the energy communities and the prosumers.

They combine production, distribution, and consumption inside the entity, with a complementary exchange of power with public network in the PCC (Point of common coupling). Typical examples are Smart districts, Smart cities, or RES (Renewable Energy Sources) cooperatives etc.

A question arises: are there needed measures for both categories (before and after PCC)? When the public network may be not able to ensure resilience till the final customer? In which situations we can have “black-outs”? Hypothetical, there are several situations (list open):

- Extreme meteorological situations, e.g., the Maria hurricane which deteriorated most of the power system five years ago in Puerto Rico. After being mostly restored, a new hurricane produced again huge network problems.

- Situations with lack of adequacy: do we have always enough power plants to order the need of consumption? Do we have enough capacity on tie-lines to cover the missing power?

- War situations: new lessons from reality (e.g., Ukraine) show how exposed is a power system.

It is as a consequence that in case that the resilience of the public grid is overwhelmed by the de facto situation, it is also needed a certain resilience at the end-user level. So, there are needed measures on both sides of the PCC (both categories).

Resilience after PCC is already used by entities with critical activity such as: hospitals, army bases and even national (and regional) dispatch centers. However, resilience of the final user is not yet sufficiently considered in many human activities and is almost non-existing at final user.

Several activities need therefore to become resilient to energy supply in cities, such as water supply (water network need electricity for pumps), public lighting – for a minimal level for security of people, activities related to public order, activities related to health care (hospitals, pharmacies etc.), activities related to bank transactions (POS etc.).

If we focus on resilience at final user, there are essential loads in a house which need to be supplied even in case of failure of supply at public network level – especially when they persist on a longer period: minimal lighting to be able to continue activity, fridge/freezer (keeping food un-altered), communication devices, including computer + internet access and so on.

It is important that such essential loads are also energy efficient, in in order to allow a longer time of energy supply.

To be noted as well that today, most of the inverters which convert DC energy of the photovoltaic panels of the prosumers are “grid followers”, which means that they do not work at all in case of power outage of the public grid, so they cannot support end-user resilience.

Off-grid and hybrid inverters can be “grid former”, so they can help in maintain a local microgrid, by using also storage means, so they can support local resilience after the PCCC.

As a conclusion, there are needed policies to promote resilience as an “important new value”: improve the support for distributed renewables, especially solar-based electricity, improve the support for investment in energy storage (specially batteries of new generation), to be combined with RES and grid-former inverters, promote resilient microgrids and energy communities

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Feng Guo, Renjin Sun

RESEARCH ON CARBON PEAK PATH OF PETROLEUM AND PETROCHEMICAL INDUSTRY FROM THE PERSPECTIVE OF DIFFERENT RESPONSIBILITIES

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Abstract:

The petroleum and petrochemical industry is not only the foundation and pillar of the national economy, but also the key sector to promote the realization of the "double carbon" goal. Because of its special industry status, the "stable development" and the "promotion of peak" have become the main keynote of the realization process of the "double carbon" goal. On the premise of reasonably meeting the energy demand for steady economic development, what will be the emission trend of the petroleum and petrochemical industry in the future? Is there any difference in the peak path under different accounting standards? Based on the energy consumption data of the petroleum and petrochemical industry from 2002 to 2017 and the relevant data of the input-output table, the paper calculates the carbon emissions of the petroleum and petrochemical industry from the perspective of production responsibility, consumption responsibility and revenue responsibility, and uses Monte Carlo Simulation model and LEAP scenario analysis method to simulate and predict the carbon peak path of the petroleum and petrochemical industry under different responsibility perspectives,

The main conclusions are as follows:

(1) The carbon emissions of the petroleum and petrochemical industry from different responsibility perspectives are quite different. The carbon emissions of the petroleum and petrochemical industry from the perspective of revenue responsibility are the largest, followed by the perspective of consumption responsibility, and the smallest is the perspective of production responsibility.
(2) The prediction results of Monte Carlo simulation show that the peak time of carbon in the petroleum and petrochemical industry is different from different responsibility perspectives. The peak time of carbon in the petroleum and petrochemical industry from the perspective of revenue responsibility is around 2035, the peak time of carbon from the perspective of consumption responsibility is around 2032, and the peak time of carbon from the perspective of production responsibility is around 2029.
(3) The results of LEAP path analysis show that under the carbon emission constraint scenario, the peak time of carbon in the petroleum and petrochemical industry from the perspective of revenue responsibility is 2033, the peak time of carbon from the perspective of consumption responsibility is 2030, and the peaktime of carbon from the perspective of production responsibility is 2028; Under the supplyside structural reform scenario, the carbon peak time of the petroleum and petrochemical in dustry from the perspective of revenue responsibility is 2031, the carbon peak time from the perspective of consumption responsibility is 2028, and the carbon peak time from the perspective of production responsibility is 2027, and the peak level will be further reduced.

Key words: Petroleum and petrochemical industry; Different responsibility perspectives; Carbon emissions; Carbon peak path

Marc Gronwald, Kingsley E. Dogah, Sania Wadud

ONE GREAT POOL, BUT WITH VARYING DEPTH: DYNAMIC EFFICIENCY OF GLOBAL CRUDE OIL MARKETS

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Overview

This paper deals with informational efficiency of global crude oil markets. It applies the quantitative measure for market efficiency recently proposed by Duan et al. (2021) in order to quantify the degree of informational efficiency of the following five crude oil price series: West Texas Intermediate, UK Brent, Bonny Light, Dubai, and Tapis. These price series represent five important oil producing regions: North America, North Sea, West Africa, Persian Gulf, and Asia Pacific. Note that UK Brent is also considered a global benchmark.

It contributes to two important streams of literature. The first is the literature on integration of crude oil markets which is epitomised by recent contributions such as Plante and Strickler (2021) as well as Bravo Caro et al. (2020). The main question this literature is concerned with is whether or not the world oil market is "one great pool". It is a unique feature of this market that crude oil is seemingly a homogenous product and, thus, the price for this product should not differ across markets in which crude oil is traded. However, the crude price series analysed in this paper not only represent different regions, there are also certain quality differences across the different streams of crude. West Texas Intermediate, to provide just one example, is sweeter than UK Brent4. To express this differently, this literature is concerned with the question whether the oil market is globalised or regionalised. The two papers mentioned above reflect the two main approaches used in this literature: While Plante and Strickler (2021) uses so-called differentials between different crude oil price series, Bravo Caro et al. (2020) apply cointegration-type approaches in order to analyse the relationship between two crude oil prices. This paper adds a new perspective to this literature by investigating whether or not the markets in question also differ in their degree of efficiency. To be more precise, the paper investigates whether or not these markets became more efficient over time and in comparison to each other.

This leads to the second contribution this paper makes: It also contributes to the literature which deals with empirical tests of the so-called Efficient Market Hypothesis (EMH). Among the most recent contribution to this literature is Assaf et al.'s (2021) analysis of the efficiency of art markets, Hull and McGroarty's (2014) analysis of financial markets in emerging economies, and Urquhart's (2016) investigation into the inefficiency of the Bitcoin market. As this paper is concerned with the degree of efficiency, the application of a quantitative measure is required. Duan et al. (2021) is useful in this regard. The advantage of market efficiency measures such as that it allows one to compare the relative degree of efficiency of one market over time or of different markets, e.g. ones which are geographically separated. The extant qualitative ones such as variance ratio tests, in contrast, only allow one to to test whether a certain market is efficient or not efficient in a certain period.

Methods

The idea of a deviation from a random walk takes centre stage in the vast literature that empirically tests the (weak-form) EMH. The conventional view is that a deviation from a random walk in financial time series implies predictability, which is not in line with the notion of efficient markets according to which all publicly available information is reflected.

[4] See Plante and Strickler (2021) for an excellent discussion of these different markets and crude streams.

Assaf et al. (2021), for example, use long-memory models, fractal dimension, and approximate entropy to analyse a possible deviation from a random walk and, thus, weak-form efficient markets. Hull and McGroarty (2014) apply the Hurst-Mandelbrot-Wallis rescaled range measure in their analysis of emerging markets while Urquhart (2016) resorts, among other methods, to the established variance ratio test. These papers' contribution lies in their analysis of under-researched or newly emerged markets; the methods they apply are already established in the literature. This catalogue of methods, however, is still being expanded upon. Recently, Kristoufek and Vosvrda (2013) proposed the so-called Efficiency Index which measures the distance from the efficient market situation using Hurst exponents, fractal dimension, and approximate entropy. Kristoufek and Vosvrda (2014) apply that method in their analysis of various energy as well as metal markets. The method used in this paper, Duan et al.'s (2021) novel measure for market efficiency, is based on the new interpretation of fractional integration. In that approach, the order of integration d of a time series can be a fractional number between 0 and 1. Duan et al. (2021) gauge the degree of efficiency of a market using the absolute difference between the estimate of d and 1. This paper employs the so-called Feasible Exact Local Whittle estimator.

Results

The main findings of this paper are the following: (1) there is evidence of time-varying informational efficiency in the crude oil markets under consideration. Efficiency is found to be low in particular during extreme oil price episodes 2008-2009, 2014, and 2020. (2) There is also evidence of differences in informational efficiency across markets.

Conclusions

The paper finds that these markets are efficient to different degrees. Thus, even though the global crude oil market is considered “one great pool”, the regional markets under consideration exhibit different degrees of informational efficiency.

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THE INTERCONNECTIONS BETWEEN FOSSIL FUEL SUBSIDY REFORMS AND BIOFUEL MANDATES

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Overview

Biofuel mandates and fossil fuel subsidy reforms have gained traction as tools for governments to achieve their climate mitigation ambitions and support a low-carbon energy transition. The fuels they target are known substitutes in the transport fuel market and are connected via international final, intermediate, and factor markets. Yet, while each policy individually has received a lot of attention they have yet to be studied simultaneously.

Method

The DRAT-BIO model, a global Computable General Equilibrium (CGE) model will be used to simulate two policy scenarios with respect to a reference case covering the period 2011-2030. The reference scenario is defined as a simulation in which the regions of the global model achieve their biofuel mandates ambition while labor productivity is calibrated to match the regional GDP growth projections of the OECD. In the first policy scenario, a gradual

phase-out of global pre-tax consumption fossil fuel subsidies will be simulated starting in 2023. In the second, post- tax fossil fuel consumption subsidies will be removed on top of the pre-tax ones.

Results

Phasing subsidies increases the price of fossil fuels and lowers consumption. Regions with biofuel mandates would therefore benefit from a Fossil Fuel Subsidy Reform (FFSR) as the government support needed to reach a biofuel consumption target would lower. Some fossil fuel consumption would however be diverted to exports, resulting in downward pressures on the world price. Regions with no or relatively low subsidies, would therefore experience an increase in fossil fuel consumption and require larger government support to reach their biofuel targets. Still, regardless of the leakage effect of both policies, the policies have an additive effect and both lead to a drop in the consumption of fossil fuels and an increase in the consumption of biofuels while lowering government spending.

Conclusion

Biofuel mandates and fossil fuel subsidy reforms have the potential to support each other's goal of an energy transition while the reform can lower the cost of the mandate. This however hides a more complex pattern of effect at the regional/country level. One may benefit or suffer in the context of the two policies being implemented globally depending on the size of these locally. Our results also suggest that prior studies on biofuel mandates who omit to include current fossil fuel subsidies over/underestimated the level of government support needed to achieve a defined policy target depending on the relative size of these subsidies.

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EXTRACTIVES: CHALLENGES AND OPPORTUNITIES FOR THE SOUTH IN THE ENERGY TRANSITION

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Abstract

While the transition to a sustainable energy system will rely on a combination of additional deployment of existing technologies, deployment of new technologies, and development of innovative technologies, all will require an abundant, secure, and sustainable supply of minerals. The International Energy Agency noted that lithium, nickel, cobalt, manganese, and graphite are crucial to battery performance, longevity, and energy density. Rare earth elements are essential for permanent magnets for wind turbines and EV motors. Electricity networks need a considerable amount of copper and aluminum, with copper being a cornerstone for all electricity-related technologies. And iron and steel are critical for the renewal and improvements of infrastructure.

Countries with abundant mineral resources have a significant economic and workforce development opportunity as they contribute to the energy transition, the Paris Agreement's objectives, and the UN's Sustainable Development Goals. And at the same time, the challenge is to make mining and processing of extractives a sustainable industry that meets the growing demand for minerals with lower environmental impacts (lower emissions, lower water use, less waste).

Latin America is an important producer of critical minerals (copper, lithium, cobalt, and nickel), considering its current production levels and participation in the global reserves of copper, lithium, cobalt, and nickel.

Chile, Peru, and Mexico hold approximately 38% of the world's copper reserves, with additional reserves found in Argentina, Brazil, Colombia, and Ecuador. Approximately 60% of the world's identified lithium deposits are found in Latin America, mainly in Bolivia, Argentina, and Chile, and some in Mexico, Peru, and Brazil. Latin America also has significant nickel reserves, where Brazil hosts 17% of the world's nickel reserves and Cobalt in Mexico and in small quantities in Brazil.[5]

This paper analyses the challenges and opportunities that LAC, a region with abundant natural resources, will have in supporting a sustainable energy transition, a role that goes beyond enhancing its energy matrix, the one with the lowest levels of CO_2 emission, and is in its protagonist to sustainably deliver the critical minerals and cleaner fuels that the world needs to sustain the energy transition.

The presence of regionally abundant natural resources – both minerals and opportunities for expanded deployment of renewable energy (solar and wind) technologies for energy and clean fuels generation - can be a driver to transform the LAC into a Natural Laboratory for the innovation of clean technologies and improved processes, which in combination can make extractives more sustainable. Through the deployment of innovative technologies and integration of workforce development efforts, the region can address the main challenges confronted by extractives in the region, including the conflict related to resource governance, the distribution of socioeconomic benefits, and the environmental impacts, CO2 emissions, waste and water use, consultation with affected communities. Examples of how some countries are confronting these issues are making extractives cleaner minerals sources to support the energy transition. Where, using science and the development of technologies, progress is made in giving greater added value to its natural resources, the country can climb in global supply chains and contribute to the objectives of the Paris Agreement and Sustainable Development of the UN.

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Ze-Ping Hu, Jin-Liang Zhang

PEAK LOAD SHAVING KEY ISSUES AND STRATEGIES OF HIGH-PROPORTION RENEWABLE ENERGY POWER SYSTEMS

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Abstract:

With the acceleration of new power system construction and the deepening of power market reform, renewable energy will quickly become the main energy supplier in China and widely participate in the power market, and its volatility and uncertainty will bring great challenges to the flexibility of the power system. Faced with the obstacle of insufficient peak load regulation resources, the paper classifies flexible resources and compares their characteristics from the perspective of “generation network load storage”. Secondly, the paper analyzes the application status and prospects of flexible resources in power peak shaving ancillary service markets. Finally, some policy recommendations are given to solve the peak shaving problem to some extent and to ensure the sustainable development of the power energy system

Hai-Yi Liu, Ming-Fang Li

DOES CARBON PRICE AFFECT RISK SPILLOVERS BETWEEN THE ENERGY AND INDUSTRY STOCK MARKETS?

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Abstract

The increasingly severe global climate crisis has threatened the environment on which human beings depend for survival. The carbon emissions trading (CET) market has been viewed as an effective way to control global greenhouse gas emissions, which is closely connected with energy and stock markets. The carbon market has gradually expanded its coverage from the initial power industry to aviation, chemical and other industries.

The relationship between carbon and energy markets or between carbon and stock markets has been studied extensively, but less consideration has been given to the time-frequency domain perspective and the linkages between energy and stock markets analyzed from the industries' perspective. This paper investigates the time-frequency dependence and risk connectedness among carbon, energy and industry stock markets using the wavelet coherence, Diebold and Yilmaz and Baruník and Krehlík methods. The results indicate that, there are a strong connectedness among carbon, energy and industry stock markets, while the risk spillovers at diverse frequency bands show apparent differences; The carbon market is a net receiver of risk connectedness, whereas the majority of equity sectors, especially energy intensive industries and financial services industries are the net transmitters of risk connectedness; finally, the major international crisis events, such as the European sovereign debt crisis, Brexit referendum, and COVID-19 pandemic have greatly intensified the risk spillover magnitude.

These results may help policymakers to formulate the risk control system, and help investors to optimize asset allocation and avoid investment risk.

Rui-Xiang Qiu, Lu-Tao Zhao

IMPACT OF RUSSIAN-UKRAINE WAR ON ENERGY MARKETS: A FORECAST-BASED EVENT ASSESSMENT

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Abstract

Since the all-out Russia-Ukraine war broke out on February 24, 2022, the Russian government has been subjected to multiple sanctions by many countries and companies around the world. Russia is one of the world's largest exporters of oil, gas and coal, and the war and sanctions have had a significant adverse impact on world energy markets. In this paper, a virtual world without Russian - Ukrainian war is constructed by a method of decomposition and integration prediction. By comparing the actual situation with the predicted results, the paper evaluates the impact of the war between Russia and Ukraine on the US gas market. Our results found that for a single month, the Russia-Ukraine war had the greatest impact on U.S. gas prices in June and September. Overall, it started to have a real impact on U.S. gas prices in May 2022, resulting in a roughly 20 percent increase in U.S. gas prices in 2022

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Enrico Gabriele

CIRCULAR ECONOMY, PATENTS AND INDUSTRIAL DESIGNS: EVIDENCE FROM EUROPEAN COUNTRIES

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Overview

This paper empirically demonstrates the macroeconomic impact of industrial designs and patents related to environmental technologies on circular economy, in line with the United Nations (2015) Sustainable Development Goal 11.6. It sheds light on how to concretely measure enforcement of circular economy into three levels on the basis of Kirchherr et al. (2017) and Potting et al. (2017), and discusses about hardships to conciliate a very large variety of definitions and schools of thought about circular economy (Homrich et al., 2018; de Jesus et al., 2018; Kinnunen and Kaksonen, 2019). Two proxies of circular economy are built up from Sankey diagram data by Eurostat (2021): 1) waste recycling on treatment; 2) linear combination of principal components to compute an indicator of total waste disposed in landfills, incinerators, recovery for energy (or other). The different roles of industrial designs and patents on each of them is discussed and tested against control variables inspired to studies by Aguilar-Hernández et al. (2021). Institutional and economic factors are also discussed in relation to circular economy.

Methods

All computations have been made from STATA 16 for Macintosh. Data from the Sankey diagram as available from the website of Eurostat (2021) is taken. Recycling and recovery rates are computed as the most basic strategy of circular economy. In order to compute the total amount of generated waste with an as more comprehensive as possible perspective, a principal component analysis is made to generate a fitted indicator which comprises a relevant portion of information by minimizing the number of eigenvectors (as from the principal component analysis). This kind of indicator is eligible to take into account the largest variety of information which could otherwise remain unexplored. Data on intellectual property rights (IPRs) and other control variables are taken from the open database of the World Bank (2021). Data for the total number of patent on environmental technologies are taken from the OECD (2021) website.

Results

Circular economy has proven evidence of positive contribution from higher "capital intensity" at macroeconomic scale, here expressed as the total number of IPR applications on GDP. This evidence is observable mainly because this paper adopts an innovative scheme from Kirchherr et al. (2017) and Potting et al. (2017), which wipes out problems of dealing with a large heterogeneity of definitions of circular economy. (Environmental) Patents and industrial designs pursued different strategies of circular economy: 1) increased recycling and recovery rates; 2) reduced total tonnes of generated waste. Especially in the last case, industrial designs issued by the EU Inner Six countries (i.e. Italy, France, Germany, the Netherlands, Belgium, Luxembourg) were found to be particularly capable of reducing the total tonnes of generated waste.

Conclusions

Control variables were found not to have so much predictive power mainly because macroeconomic effects of circular economy are easier to be detected by forward-looking projections. Indeed circular economy is still an emerging industry which comprehends plenty of microeconomically-scaled business cases. Methods here illustrated prove that macroeconomic evidence was not so immediate to be appreciated, but signs of how to scale it at macroeconomic level might be held from this paper. In our opinion, a clear definition of circular economy may encourage to its diffusion and wider social consensus.

The main rationale of this paper might be summarized as following: circular economy could represent a good mechanism to decouple energy-intensity and economic growth (or development at higher levels of per-capita income). This paper argues that the abovementioned tradeoff between environmental preservation and economic growth can be overcome through clear strategies of circular economy.

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Nicola Sorrentino, Daniele Menniti, Anna Pinnarelli, Fiorella Stella, Gaetano Polizzi

RENEWABLE ENERGY COMMUNITIES: BENEFITS BEHIND THE SELF CONSUMPTION

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Overview

In recent years, technologies put in place for distributed energy supply have seen a proliferation of opportunities related to the development of renewable energy communities (RECs), which are considered to bring important innovations to support the transition of the energy system to a more sustainable model. Support that is more urgently needed than ever considering the further raising of EU targets for reducing CO_2 emissions to 55 %, for which the energy sector is responsible for more than 75 % [1]. RECs initiatives, refer to attempts to implement an energy transition that can involve a plethora of organizations and different forms of "community-based" projects to include users and citizens in organizational and decision-making processes related to co-production and consumption of energy. These new forms of aggregation offer citizens the opportunity to take an increasingly prominent role in achieving the goals of decarbonizing the electricity system. Thus, the energy community should be understood as a social, cultural and economic reality that locally self-produces the energy necessary for its needs, judiciously using land resources within the limits imposed by the patrimonial stock, thus protecting its common, territorial, environmental and landscape assets and directing itself toward reducing its ecological footprint [2]. The benefits that RECs can generate have spillover effects on the power grid and more generally on the energy system [3]; within communities, highlighting the social benefits of developing collective projects; and at an environmental and territorial level, depending on the enhancement of the resources available to the community.

Methods

This paper aims to demonstrate the validity of RECs in terms of environmental benefits and in terms of benefits to the power system, through the use of an assessment tool that will estimate, in particular, the share of CO_2 emissions produced, the amount of energy required during critical hours (maximum load demand for the power system estimated by the transmission system operator (TSO), and the self-consumed energy capacity of active users. The proposed evaluation methodology aims to compare and evaluate the behavior of an energy community in terms of the share of CO_2 emissions, the amount of energy required during critical hours (maximum load demand for the electric system estimated by the transmission system operator (TSO), and the self-consumed energy capacity of active users. The tool was implemented and tested in an Italian scenario in which some numerical results were used, taking data from real residential users located in southern Italy.
The analysis considers data from 100 Smart Meters (SMs) associated with users of different types (consumers and prosumers) in order to evaluate the effect of potential community clustering of these users. The evaluation is done based on the measurement of three indices: CO_2 produced, self-consumption and grid support, and the number of critical hours for the electricity system.
Next, the inclusion of a community storage system was simulated, and the same indices given above were reconsidered to assess its usefulness

The simulations took into account 2 different scenarios:

- **Basic Profile (BP) VS Energy Community Profile (ECP):** In this scenario, the basic profile and the energy community profile are compared . The first one considers only the load values of all users who are simple consumers. On the other hand, the second profile considers a community PV system to satisfy the total load.

- **Basic Profile VS Energy Community Profile (ECP) VS Energy community storage profile (ECSP):** In this second scenario, the profile obtained through the use of an appropriately controlled community storage system is also added to the comparison.

Result

This section, illustrates the results obtained through the simulations performed.

- **Basic Profile (BP) VS Energy community profile (ECP)**

  The basic profile takes into account only the load values of all users. Thus, all users are evaluated as if they were consumers. The case in 'community', on the other hand, relates to the use of the PV system to meet the total load. Below, in Table 1, the results of the indicators are shown, comparing: tons of CO2 produced; MWh of self-consumption and produced by the plant; number of critical hours when the load is lower than the base profile. As shown in Table 1, looking at the BP and ECP (PV) profiles a reduction in CO2 production can be seen, which registers 117,86 Tons in the BP while in the ECP it drops to 86,39 Tons.

	BP	**ECP**	
CO_2	**Tot. tCO_2**	**Tot. tCO_2**	
	117,86	86,39	
Critical Hours	/	**Nr. critical hours with higher load HP (max. 500)**	
		286	
		Tot. Higher load (MWh)	
		9,17	
self- consumption		**Sum self-consumption MWh**	**Sum PV MWh**
		133,63	191,98

Table. 1 – BP VS ECP (PV)

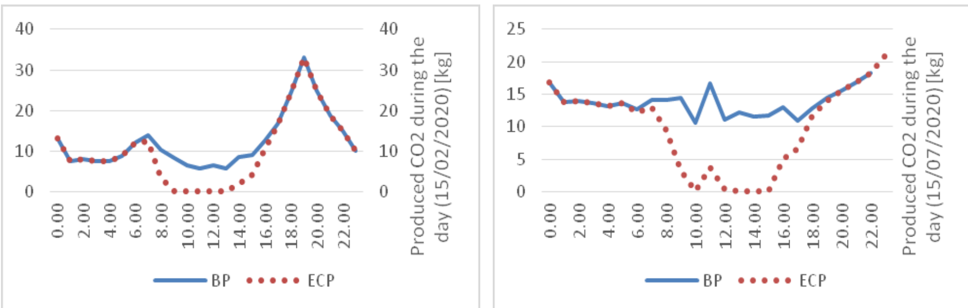

Figure 1 - Focus on CO_2 production on 15/02/2020? and 15/07/2020

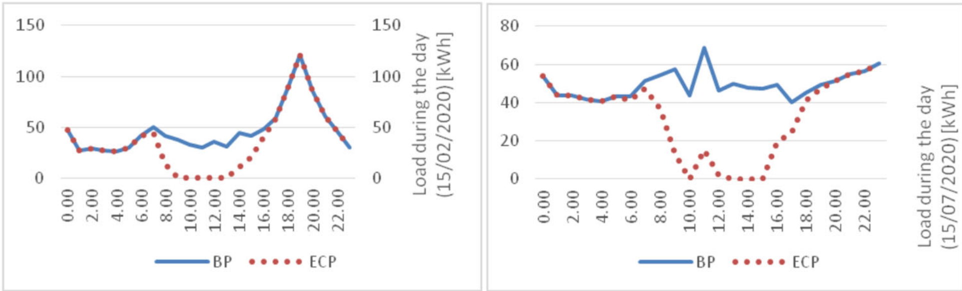

Figure 2 - Focus on residual load profiles on 15/02/2020 and 15/07/2020

In *Figure 2*, it can be seen that the trend is similar to that in *Figure 1*. A higher load ramp is evident in the evening hours when PV production ends and this negatively impacts grid stability

Figure 3 shows how a lower load is evident in the ECP than in the BP

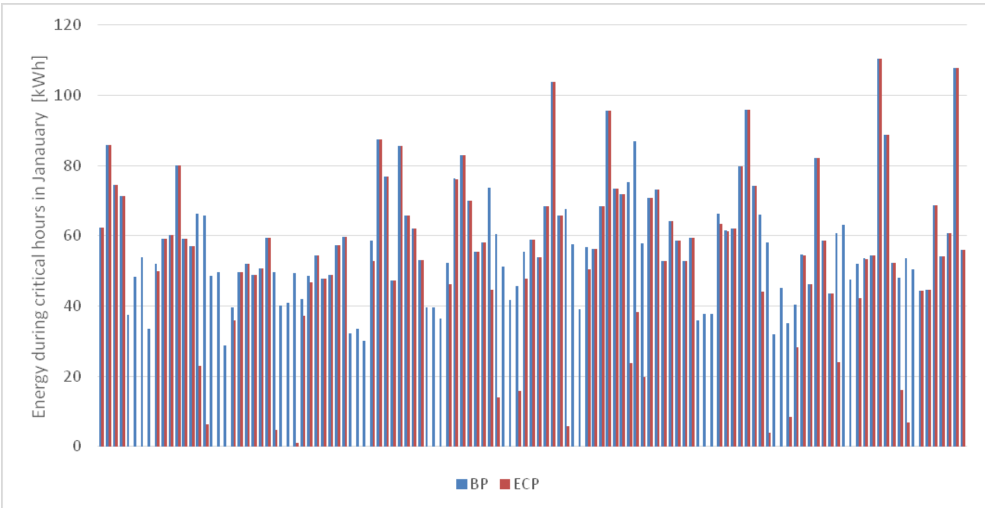

Figure.3 - Comparison of critical hours in January

- **Basic Profile (BP) VS Energy community storage profile (ECSP):**

The baseline profile considers only the load values of all users. Therefore, all users are evaluated as if they were consumers. The "community" case, on the other hand, refers to the use of the PV system plus a storage system. Below, *Table 2* shows the results of the indicators comparing: tons of CO_2 produced; MWh of self-consumption and produced by the system; and the number of critical hours when the load is below the baseline profile. As shown in *Table 2*, looking at BP and ECSP (PV+ESS) profiles, there is a reduction in CO_2 production, which records 117.86 tons in BP while in ECP it drops to 69.58 tons.

	BP	**ECSP**	
CO_2	**Tot. tCO_2**	**Tot. tCO2**	
	117,86	69,58	
Critical Hours	/	**Nr. critical hours with less load PV (max. 500)**	
		500	
		Tot. Higher load (MWh)	
		13,05	
self- consumption		**Sum self-consumption MWh**	**Somma PV MWh**
		191,94	191,98

Table 2 – BP VS ECP (PV+ESS)

The graphs show the load profile trends for 15/02 (*Figure.4*) and 15/07 (*Figure.5*). BP, ECP and ECSP are compared. As in the previous case, in the BP vs. ECP comparison, it is evident that the use of the community plant helps to meet the energy demand during the production hours (7 a.m. to 5 p.m.) but that, as a result, the evening ramp-up is much steeper. To overcome this problem, it was chosen to use a storage system so as to absorb the surplus during times of overproduction and use the energy when needed. This stored energy was managed to dampen the evening profile rise. To do this, the discharge of the storage was controlled so as to deliver the stored energy gradually.

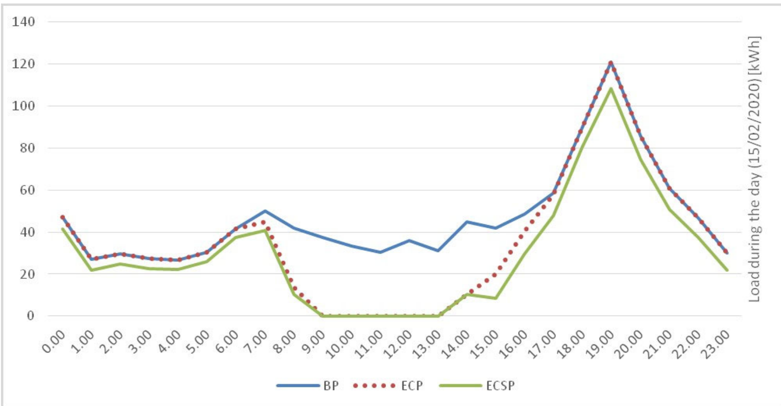

Figure 4 - Focus on residual load profiles on 15/02/2020

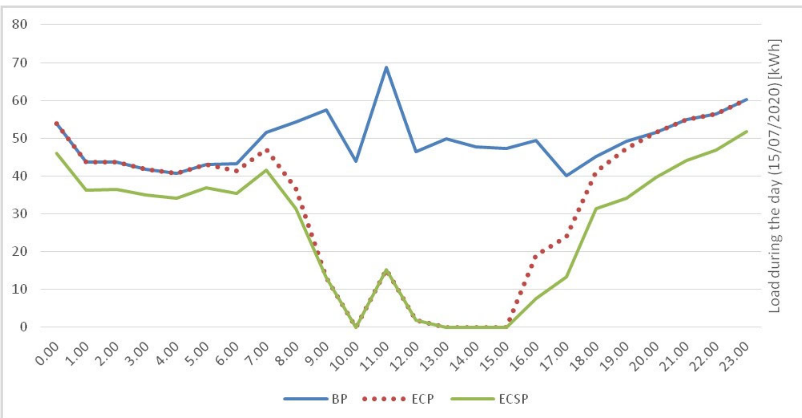

Figure 5 - Focus on residual load profiles on 15/07/2020

The critical hours are the third aspect that is evaluated, seeing the critical hours for the electrical system, hours in which there is a more significant load and therefore a greater risk to having a system blackout. In Tab. 3, it can be seen that due to the accumulation, it is possible to have a lower load.

	BP	ECSP
Critical Hours	/	**Nr. critical hours with less load PV (max. 500)**
		500
		Tot. Higher load (MWh)
		13,05

Table 3 - Comparison of critical hours

Conclusions

Energy communities represent one of the opportunities through which it will be possible to achieve the goals that the European Union has set for 2050. Their implementation is important for several reasons: to fully exploit the potential of the area; to spread RES installations; to enhance the role of citizens and local communities; to raise awareness of the importance of user behavior on the economic and environmental aspect.. They also enable local energy rebalancing and energy upgrading of consumption places as well as develop technical or professional skills in the area with economic and social spin-offs. RECs are also tools designed to combat energy poverty by reducing energy supply costs and consumption.
Since few years, Italy has decided to firmly enter the field of renewable energy communities. The approval of the Decreto Milleproroghe firstand the transposition of the RED II and IEMD directives later, are important steps that outline the legislation related to RECs.. One solution to promote energy communities involves economic incentives that can be quantified by taking into account the multiple benefits of renewable energy community self-consumption. According to this scope, in this paper, the authors have analyzed the RECs benefits in terms of both environmental, in particular CO_2 emission reduction, and electricity system adequacy ones, in particular in terms of load reduction in critical hours. Such benefits are obviously related to the rate of collective self-consumption.
Numerical results highlighted the advantages that energy communities can bring to the energy system in a variety of ways. Through the good use of RES and storage system, enormous benefits for users and the system can be achieved. Through these indicators it is possible to design appropriate incentives scheme for REC that takes into account all the obtained benefits

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Marina Bertolini

ENERGY COMMUNITIES EVALUATION: A COST-BENEFIT APPROACH

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Overview

The European Union defines energy communities as “Entities that are entitled to: i) "produce, consume, store and sell renewable energy, including through renewables power purchase agreements"; ii) "share, within the renewable energy community, renewable energy that is produced by the production units owned by that renewable energy community, and maintaining the rights and obligations of the renewable energy community members as customers"; iii) "access all suitable energy markets both directly or through aggregation in a non-discriminatory manner"”.
Energy communities are considered one of the major opportunities to foster the Energy Transition by involving small agents, i.e. consumers and prosumers, in the management of local electricity systems and markets. The decentralization of energy markets, indeed, will allow the participation of local producers and loads to the exchanges, contributing to a new management of balancing costs and grid costs (Agostini et al., 2021), with several impacts on the power system (Dudjak et al., 2021). All the potential participants shall have the opportunity to be involved in the new energy markets: being the household the smallest agent in this mechanism, he/she can decide to join a group to participate the market with. Energy communities shall be the also the place where to implement best practices to improve energy efficiency.
Despite the fact that the purpose of the energy communities is worthy of interest and potentially positive for the energy transition process, it is necessary to underline that there is still no approach in the literature - and even more in the first pilot experiments that we can observe around Europe - that allows us to effectively evaluate these initiatives by adopting a rigorous cost-benefit valuation. De Wildt et al. (2019), for example, clustered a number of potential negative impacts that might arise by including different agents in a smart grid, including potential mismatch between costs and benefits for agents inside the community. The impact of high decentralized participation shall be also evaluated for the system as a whole. A relevant perspective for the assessment is that of the municipality, since this entity is playing a relevant role in involving citizens in the energy transition process.
The purpose of this work is to update and to assess a cost-benefit methodology for the evaluation of energy community initiatives.

Methods

The paper will review the literature regarding the Cost-Benefit Analysis methodology, especially that applied to the evaluation of energy systems and networks. Then, the authors will focus on the classification of costs and benefits arising from the activation of a community.

Results

The work will lead to an updated Cost-Benefit analysis to be applied to energy community projects. The major effort of the project will be linked to the perimeter of the projects, identification of the stakeholders and the evaluation of the effects.

Conclusions

TBD

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Giuseppe Dell'Olio

HOW SUSTAINABLE IS COGENERATION? A LONG-TERM, REAL-LIFE EVALUATION

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Overview

Cogeneration (or "Combined Heat and Power", CHP). is spreading worldwide more and more. One of the causes of such a success are, of course, the incentives granted by many States, which have at last acknoledged the importance of this technology for the overall energy efficiency.

It is then natural to wonder which of the technologies available for electricity production are best suited to be employed in cogeneration: the answer to this question may provide guidance both to installation designers who have to choose a technology for a specific application, and to policy makers who are responsible for allocating public subsidies.

Methods

More than six hundred generating units, of different technologies (gas turbines, internal combustion engines, steam turbines etc.) were analysed. For each generating unit, "real life" operation data were collected for years 2011 to 2019 (more than 12.000.000 equivalent operating hours); based on those data, a few efficiency indicators were calculated as weighted averages. Indicators include: electric efficiency; thermal efficiency; overall efficiency; Power to Heat Ratio (PTOH); Primary Energy Savings index (PES); equivalent operation hours (Heq); load factor.

Electric efficiency is the ratio of electricity produced by the CHP unit in a given year to energy (fuel) consumed to do so.

Thermal efficiency, on the other hand, is the ratio of heat produced by the CHP unit in a given year to energy (fuel) consumed to do so.

Overall efficiency is the sum of the above efficiencies.

Power to Heat Ratio (PTOH) is the ratio of electricity to useful heat, produced by a CHP unit in a given year.

A CHP unit with a high PTOH produces a larger amount of "valuable" energy (electricity) than a unit with a lower PTOH.

A high PTOH indicates that the heat carrier (e.g., steam) was exploited efficiently, as it produced a significant amount of electricity before being further used for thermal purposes.

Primary Energy Savings index, or PES, is an estimate of the amount of fuel that was saved by producing electricity anh heat jointly, as compared to producing them separately.

Heq is the number of hours during which a given generating unit would have been in operation, if it had constantly been kept at maximum load. For each generating unit, the equivalent operating hours (Heq) have been calculated by dividing the annual electricity production by the unit power.
Heq was in turn divided by the actual yearly operating hours (Heff), where available. This yielded the "load factor" (Fc), always less than one.

Statistical correlation among indicators was also investigated for each technology; this includes, i.a.:
- correlation between equivalent operation hours and electric efficiency;
- correlation between equivalent operating hours (Heq) and load factor (Fc)
- correlation between electric efficiency and thermal efficiency

Results

Internal Combustion Engine (ICE) has, of all technologies, the highest Power to Heat Ratio (PTOH) and electric efficiency. Furthermore, electric efficiency is not significantly dependent on the year of commissioning.

The high value of load factor Fc, together with a low Heq, suggests that ICEs can be -and are- started and stopped rapidly, which keeps the duration of partial load operation very short. In particular, micro ICEs show a very strong, inverse relationship between electrical efficiency and thermal efficiency: this suggests that the amount of heat wasted is low.
Unlike ICEs, gas turbines have an excellent overall efficiency, but a rather low electric one. This seems to be an intrinsic characteristic of these turbines, since the electric efficiency does not depend significantly on the equivalent operating hours (Heq).

PTOH, too, is lower for gas turbines than for IECs.

Gas turbines also seem to have reached technological maturity: electric efficiency is virtually independent of commissioning year.

Steam turbines feature lower efficiencies and PTOH, and tend to suffer from load variations: the small-scale ones show a strong direct correlation between equivalent operating hours (Heq) and electric efficiency. This is consistent, incidentally, with another strong direct correlation: that between load factor (Fc) and equivalent operating hours (Heq). Apparently, frequent starts and stops (which are the most probable cause of low Heq) are associated with low load.

Conclusions

Internal Combustion Engine appears to be the technology which is best suited for high efficiency cogeneration: it is able to continuously adjust to heat load variations, while maintaining high PTOHs and efficiencies (although low power ICEs tend to perform better on the overall efficiency than on the electric one). ICE is to be regarded as a mature technology by now, as it shows no significant increase of electric efficiency since 2011 (micro ICEs even show a slight decrease).
Statistical analysis confirms that the amount of heat wasted is low in all operational conditions; this is yet another proof of overall high performance for this technology.
Gas turbines are somehow less performant: they reach lower electric efficiency and Power to Heat Ratio PTOH. No efficiency improvement is to be expected from a more regular operation, or from technological progress.
Steam turbines are less than satisfying, due to their low efficiencies and PTOH, and poor aptitude to variable load operation. Statistical analysis shows that frequent starts and stops may hinder the full exploitation of the turbine (low load factor Fc). This suggest (or confirms) that steam turbines need long times to reach full load after start up, which is an evident operational drawback as compared to gas turbines or internal combustion engines.

Janez Dolšak

THE HISTORICAL EVOLUTION OF DETERMINANTS OF ENERGY EFFICIENT RETROFITS IN RESIDENTIAL SECTOR

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Overview

The European Union (EU) residential sector consumes 27.2% of final energy (Eurostat, 2019a) and is responsible for 24% of CO2 emissions (Eurostat, 2019b), of which the majority is for heating buildings. The building stock in the EU is relatively old, with about 35% of buildings over 50 years old, and consequently three out of four are considered energy inefficient (Econmidou, 2015). However, progress in energy efficiency in the EU28 is very slow, with only 0.2% of buildings being retrofitted each year (Esser et al. 2019). To design effective policies to promote future energy savings in residential buildings, policymakers need to be informed about the condition, occupancy, and performance of buildings, the type of heating system and heating behaviour, and the cost and availability of retrofit measures. Armed with this knowledge, policymakers can increase retrofit rates through regulatory measures and tax incentives. However, to increase the effectiveness of these approaches, they must be tailored to the climatic and cultural conditions of each country. Without understanding the country-specific determinants of energy-efficient measures, policy outcomes may be low. Particularly important in addressing energy efficiency gaps is addressing behavioural factors, i.e., finding out what motivates households to implement energy efficiency measures and what prevents them from doing so (Wilson and Dowlatabadi, 2007). There is a considerable amount of knowledge in the literature on the determinants of energy efficiency, but these studies do not include all determinants, countries, or climate zones in a comprehensive manner (Jakob, 2007; Friege and Chappin, 2014; Palm and Reindl, 2018).

The main research question of this study is the following: What are the key determinants of residential energy efficiency measures and what are the relationships among studies that identify these determinants? The research objectives are as follows: First, this paper aims to provide a comprehensive literature review on the determinants of energy efficiency measures. Specifically, the bibliometric analysis is used to create a visualised knowledge of the historical development of the topics covered in the literature. Second, the detailed review of selected papers led to the identification of determinants of energy efficient measures in the residential sector. Third, an attempt is made to identify emerging research areas and potentials for future research.

Methods

To search for documents, I used the Web of Science database (WOS), one of the most widely used databases by practitioners. These databases are capable of providing citation lists and counts, which is necessary for subsequent bibliometric analysis. WOS has proven to be the only publication and citation database that has a long history of covering many scientific fields, and thus I chose to use it because this study aims, among other things, to examine the historical development of topics in the area of determinants of energy efficiency in the residential sector. There are also other potential databases such as Google Scholar and Scopus, but due to the limitations mentioned above, the final decision was made to use WOS. In the first phase of the bibliometric analysis, I conducted a preliminary literature search of existing papers that led to the identification of topics, keywords, and other characteristics of the scholarly literature that guided the subsequent narrower search. The selection of terms was based on the most commonly used terms, including their various forms and synonyms.

Results

This paper examines 1198 research publications published between 1993 and 2022 (see *Figure 1*). Although the query was not timed, the earliest publication is from 1993, which is consistent with the results of Simpson et al. (2020), who identified the first publication in 1985, and the trend of their publications is also very similar to mine. Figure 1 also shows that while the factors affecting energy-efficient home retrofits have been studied for several decades, most research publications have appeared in the last decade. Throughout the period, the average growth in published papers has been more than 17 per year. However, there has been a significant change in growth during this period. In particular, there were almost no publications until 2004, which is related to the slow development of energy efficiency policies. When almost all developed countries included energy efficiency as one of the main objectives of their national strategies, the number of publications started to increase. The full scale of energy efficiency policies in 2010 most likely caused an exponential growth in the number of publications. It should be mentioned that after 2017, the growth slowed down significantly or even started to decrease, which was reflected in a sharp decline from 2018 to 2019. In 2019, the growth continued until the end of the period.

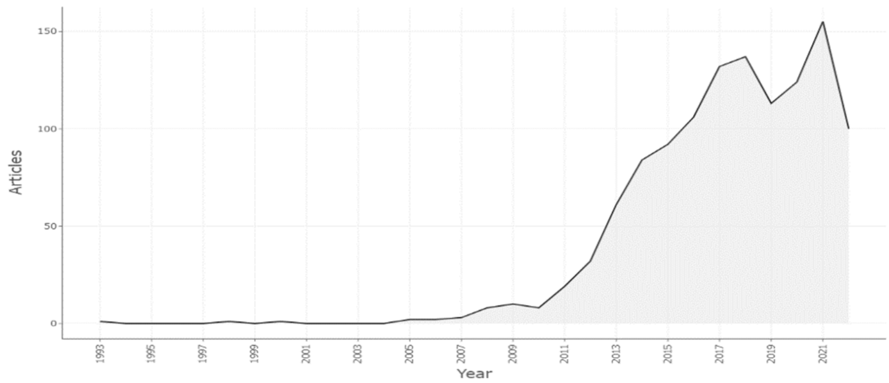

Figure 1 - Annual scientific production from 1993 to 2022

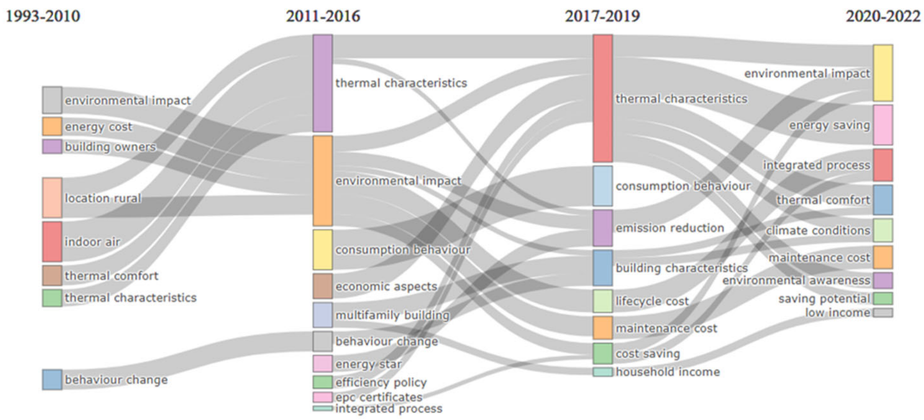

Figure 2 - The historical evolution of determinants of energy efficient retrofits

Next, I provide an overview of the main determinants identified in the literature (see Figure 2). In the early period up to 2010, when not many documents have been published, the most important determinants are indoor air, rural location, and environmental impact. Other determinants such as energy cost, thermal comfort, and behaviour change were less frequently cited. This suggests that research was often concerned with rural areas, focusing on indoor air quality, while thermal characteristics were not. In the second period from 2011-2016, the most important determinants were thermal properties, environmental impacts, and consumption patterns. These three determinants were included in most published documents.

Other determinants that appeared in this period were economic aspects of retrofitting, policies that introduced programmes such as Energy Star and EPC certificates, and especially multifamily housing. In the third period (2017-2019), thermal characteristics of residential buildings received by far the most attention, followed by consumption patterns and emissions reductions. The latter was taken up for the first time in the history of research in this field probably as a result of scientific findings on the emission burden of the residential sector. Economic aspects play an important role in this period, as cost savings, maintenance costs, and life cycle costs of existing buildings and their features are highlighted. In the last period, 2020-2022, the main determinant is again the environmental impact, followed by energy savings and integrated processes. With the emergence of the new economic crisis, the need for energy savings and the implementation of energy retrofits as part of an integrated process becomes clear, which consequently reduces the overall cost. In the last period, the focus is on environmental issues and the reduction of energy costs.

Conclusions

Growing concern about household energy poverty has stimulated discourse about policies to overcome this problem. Energy-efficient retrofits continue to represent the greatest potential for reducing energy costs and improving household living conditions. However, households' decisions to implement such measures tend to be influenced by a variety of factors that act as either drivers or barriers. In this study, research trends on the determinants of energy-efficient retrofits were examined using a bibliometric analysis. Information on determinants was collected from 1198 documents published between 1993 and 2022. The analysis showed that in the 30 years of publication, most documents were published in the last decade with a very rapid growth. Interestingly, the number of published documents decreased significantly in 2018, while it increased again the following year. This possibly shows that the interest in energy efficiency decreased due to the emergence of new technologies, while the importance increased again in the following year. The development of the determinants clearly shows the impact of global research trends.

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Zixuan Wang, Edi Assoumou, Antoine Monnet

LONG TERM IMPACT OF HYBRID HEAT PUMPS (HHP) ON ELECTRICITY SUPPLY SECURITY – CASE STUDY WITH FRENCH ENERGY SYSTEM

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Overview

Residential heat pumps transform heat from external environment to useful energy for space heating. Heat pumps are widely recognized as important solution to decarbonize residential energy consumption. However, one shortage of this heating option is that, the energy efficiency (COP) of heat pumps depends highly on outside temperature conditions. And during extreme cold period when residential demand of space heating reaches to peak, the energy efficiency of HPs will largely reduce, thus generating very high electricity demand. Energy supply security issue needs to be considered when planning for a large-scale HP integration in residential buildings. Current electricity grid might not be able to cover all the power call from HPs during peak period in the future, especially during extreme cold weather conditions. Besides, massive network expansion might be required to adapt to the peak demand profile, which represents heavy investment.
A hybrid HHP is a flexible energy solution which can switch between heat pump and gas boiler to provide heat for residential sector. When outside is very cold, a HHP can use completely gas boiler to produce space heat. It can thus significantly reduce equipment's contribution to peak electricity power call. This is a beneficial aspect to energy system as supply security can be guaranteed by alternative gas solution even if the capacity of electricity network is not sufficient. However, as the HHPs rely highly on gas, they are not completely decarbonized solution if the gas mix is fossil dependent. This needs to be considered when we face a strict environmental constraint.
The long-term role of HP and HHPs are still unanswered question, while energy security is one dimension that cannot be ignored. For energy planning, it is important to account for extreme situation, for example, a special cold winter. Besides, environmental constraint, economics rationality, RES potential may also have considerable impacts.

Method

We try to elucidate the effect of HP and HHPs on energy security in the long-term energy transition in France. More specifically, we focus on the changes of electricity supply structure that introduction of HP and HHP for building sectors can bring, especially during peak period. Besides, HHP as a flexible heating solution can play an important role on guaranteeing energy supply security under carbon neutrality context. Our research will be based on a bottom-up TIMES model which represents the entire energy system of France. The technical and economic performance of HP and HHP technologies under different temperature conditions will be represented in detail in a system-wide modelling approach. We will distinguish and discuss the implication of the efficiency and operating mode of HPs and HHPs during warm, cold and extreme cold period.

Our study will propose an improved modelling structure for HP and HHP technologies and assess its impacts under different scenarios. Our modelling results will show transition of final energy demand of French energy system, detailed energy investment choice (installed capacity) of residential buildings, as well as electricity supply structure during peak periods till 2050. By comparing scenarios, we will investigate the choice of heating technology with a focus on hybrid heat pumps under different conditions. For example, we will figure out if HHP can be important choice for residential heating if there is extreme cold period in the future.

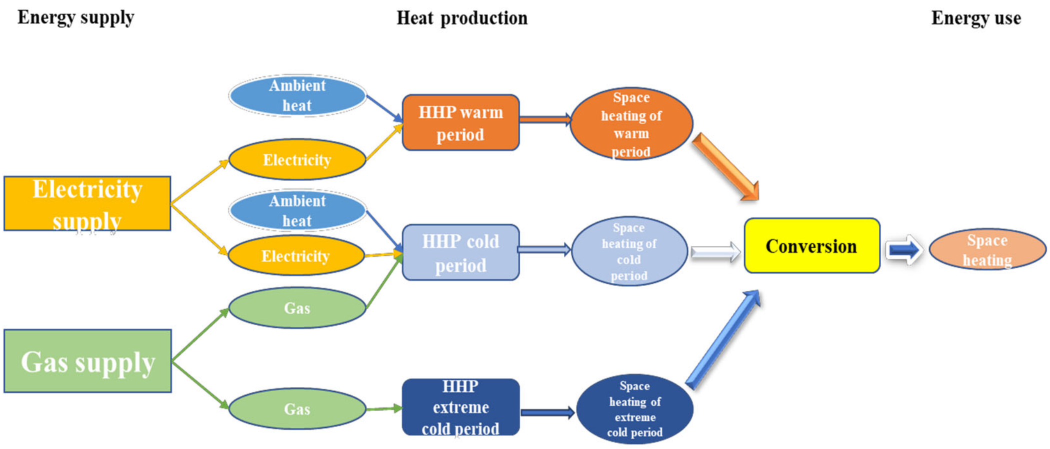

Figure 1 - Improved modeling structure of HP technologies in TIMES-FR

Besides, we will give detailed description on how the peak load of end-use sectors are supplied by different types of power plant. By comparing the cases with and without HHP integration, we will illustrate the effects of HHP on peak electricity supply-demand situation. These are important aspects of electricity supply security.

Jieyang Chong, Jacopo Torriti

TIME-VARYING PRICE ELASTICITY OF ELECTRICITY DEMAND

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The ability to induce shifts in electricity load within a day may reduce costs for a number of reasons. Lowering daily peaks or managing foreseeable spikes in demand are useful for system security. Similarly, taking advantage of favourable weather conditions with respect to generation of renewable energy could also be achieved through successful load-shifting. One of the ways in which this outcome can be targetted is through the use of financial incentives. In designing a suitable monetary incentive or deterrent for consumption, knowledge of the expected demand response to an effective change in electricity price is key. In the context of intra-day shifting, understanding how the profile of price elasticity varies within a day is of particular relevance.

Estimation of intra-day patterns in price elasticity of electricity demand has received limited attention in the lit- erature (Fan and Hyndman, 2011; Knaut and Paulus, 2016; Kulakov and Ziel, 2019; Chong, 2021) and has re- cently become topical in light of the gas shortage and soaring electricity prices in Europe. This study proposes a new econometric approach which introduces smoothness in the intra-day pattern of elasticity, and preserves this smoothness of elasticity in a cyclical manner. Smoothness in elasticities is argued in the paper to be characteristic of data which captures aggregated consumption behaviour (e.g. whole population, the residential sector, all office buildings in a city) as opposed to individual or household-level data. Since time of day is measured in a cyclical manner, it follows that if elasticity is smooth, it must be so in a cyclical manner. In other words, even though each day arbitrarily starts at the first measurable moment after midnight, when elasticity between midnight and this time is continuous, it can be considered to be "cyclical".

Methods

The method proposed in this paper follows an econometric modelling approach not dissimilar to those in existing works. A linear model of the form

$$y_t = cp_t + \boldsymbol{x}_t^{!}\boldsymbol{\beta} + \varepsilon_t, \tag{1}$$

in which y_t represents electricity demand at time t, p_t represents price, and $\boldsymbol{x}_t$ is a vector of other variables with explanatory power on demand including an intercept. The coefficients c and $\boldsymbol{\beta}$ are to be estimated. The way in which demand and price enter the equation as y_t and p_t , respectively, varies between being the natural logarithms or raw levels in the literature. For example, Tiwari and Menegaki (2019) use logarithms for both variables, Fan and Hyndman (2011) uses a log-linear model in which demand is in logarithms and price is in levels and also a log-log model, and Lijesen (2007) uses both a linear model as well as a log-log model. Price elasticity estimates are then obtained from some transformation of the estimate of c in (1), depending on whether y_t and p_t are in logs or levels.

Unlike Fan and Hyndman (2011) and Knaut and Paulus (2016), the proposed method for estimating a daily pattern in price elasticities fits a single regression equation to the data instead of performing a regression for each intra- day period. This approach makes it easy to test whether a daily pattern exists. Variations in price elasticity can be introduced by including an interaction variable between price and a dummy variable for each intra-day period as in

$$y_{d,h} = c_0 p_{d,h} + \sum_{j=1}^{H-1} c_h \mathbb{1}\left(h = j\right) p_{d,h} + \boldsymbol{x}'_{d,h}\boldsymbol{\beta} + \varepsilon_{d,h}, \tag{2}$$

where d is the day in the sample, H is the total number of periods per day, and h is the intra-day period. The function $\mathbb{1}(\cdot)$ takes the value 1 if its argument is true and 0 otherwise. The equivalence between subscripts in (1) and (2) is given by $t = (d - 1) \times H + h$. The estimated price elasticity at the h-th intra-day period is then computed using c_0 and c_h, with the elasticity at the H-th period computed using only c_0.

Testing the joint significance of $c_1, \ldots, c_{H-1}$ is effectively checking for evidence of variation in price elasticity throughout the day. Note, however, that (2) does not impose smoothness on elasticities even if $H \to \infty$.

An alternative way of introducing easily-testable variation in price elasticities throughout the day is through the model

$$y_t = c p_t + \sum_{q=1}^{Q} \left[\gamma_q \sin\left(\frac{2q\pi(t-H)}{H}\right) + \delta_q \cos\left(\frac{2q\pi(t-H)}{H}\right)\right] p_t + \boldsymbol{x}'_t\boldsymbol{\beta} + \varepsilon_t, \tag{3}$$

where Q can be selected using the data. In this application, the value of Q is selected by recursively increasing the value from $Q = 0$ until some $Q = Q^*$ such that γ_{Q^*+1} and δ_{Q^*+1} are both not statistically significant. If $Q > 0$, then price elasticity throughout the day is not constant. This Fourier approximation estimates a repeated pattern of elasticity within each day and ensures that elasticity is smooth throughout the sample.

All three models are estimated by two-stage least squares using p_{t-1} as an instrument for p_t .

Results

Using hourly data from the German wholesale market for the year 2016 which is obtained from the European Power Exchange (EPEX), price elasticity is estimated by (i) fitting model (1) to the whole sample (constant elasticity),
(ii) fitting model (2), and (iii) fitting model (3). Since prices in this sample fall below 0, the logarithm of price is not defined for the whole sample, and the log-log specification is not feasible. All models are estimated with linear (demand and price in levels) and log-linear (logarithm of demand and price in levels) specifications.

The joint tests from (2) and (3) both indicate that there is variation in price elasticity of electricity demand within the day. Estimates of price elasticities using both models exhibit similar patterns, with a range of values which includes the constant estimate from (1). The pattern of estimates from the dummy variable model described in (2) is noticeably less smooth that those of (3), especially between 1500–2100hrs. Electricity demand is found to be most elastic between 2100hrs and midnight, and least elastic around 0700–0800hrs and between 1800–2000hrs. Intra-day elasticities from (2) and (3) fall within similar ranges of price elasticity whether a linear or log-linear specification is used.

Conclusions

This paper proposes a new and simple way to estimate smooth variations across the day in price elasticity of electricity demand. The proposed method also provides an easy way to test whether price elasticities are constant throughout the day or whether there is evidence of variation.

Applying the approach to German wholesale electricity data provides estimates for price elasticities which vary throughout the day and this variation is found to be statistically significant.

Judith Stute, Matthias Kühnbach

CURRENT DEVELOPMENT ON THE GERMAN DAY-AHEAD SPOT MARKET: CURSE OR BLESSING FOR THE UTILIZATION OF FLEXIBILITY BY HOUSEHOLDS?

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Overview

The increasing use of technologies such as electric vehicles (EV), heat pumps (HP) and PV battery storage systems (BSS) are leading to an increasing demand for electricity of household customers in Germany. The increased demand of household customers will have a significant effect also on distribution grids in Germany [1,2]. In addition, digitalization is giving electricity customers new opportunities to control and optimize their electricity consumption. For example, by using a home energy management system (HEMS).
This flexibility of electricity consumption can be additionally stimulated by variable electricity tariffs. The benefits of variable electricity tariffs depend to a large extent on the tariffs offered [3–6]. These tariffs are already offered by utilities today and range from 2-tier ToU tariffs to tariffs based on the day-ahead spot market price (e. g. “Tibber” [7], “aWATTar” [8] or “Polarstern” [9] in Germany).
In the first year of the COVID-19 crisis, the average price in the wholesale electricity market decreased to
€30.47/MWh (from €37.67/MWh in 2019). In 2021, the average price increased to €96.84/MWh [10]. This represents an increase of around 157% compared to 2019. The price differences within a day also increased sharply. This development on the wholesale electricity market is currently reflected in household electricity prices.
The following research questions arise for us: what are the implications of developments in the day-ahead market for the benefits of dynamic tariffs? What are the economic implications for residential customers? What are the implications for household load and the use of flexibility?

Methods

We address these research questions by analyzing day-ahead spot market prices for 2019 through 2021. Next, we define three different tariffs based on the day-ahead spot market price with varying price spreads and average prices and simulate the selected tariff structures for more than 300 metered household load profiles, in order to account for the heterogeneity of household customers. For all households, we vary the availability of different technologies such as PV systems, EVs, BSSs, and HPs. In our analysis, we minimize household electricity procurement costs by using a HEMS. We do this by using an optimization model that integrates inflexible demand, BSS management, and demand response from EVs and HPs.

Results

The analysis of the day-ahead spot market prices shows, that especially for the last quarter of 2021, price spreads and the average price are rising sharply. Taking those developments into account in the selected tariffs, our results show, that with the current development of higher price spreads at the day-ahead spot market, utilizing the flexibility of BSS, EVs and HPs will become economically more attractive for household customers. With lower price spreads, self-consumption is more attractive for customers. The maximum grid load of a household does not differ much between the different price scenarios, whereas the amounts of energy fed into and drawn from the grid over a year are dependent on the price scenario.

Looking at the availability of different technologies, the results show, that the highest cost savings when using the dynamic tariff can be made for households with an EV. PV systems and BSS in combination with EV and/or HP do help to further increase the possible cost savings. Overall, the differences in cost savings but also in maximum grid load between the individual households show a high range.

Conclusions

As the maximum grid load of a household does not differ much between the different price scenarios, we can see, it does not depend on the given price spreads at the day-ahead spot market. At the same time, having higher price spreads leads to a much higher financial attractiveness of utilizing flexibility for household customers.
Therefore, the current developments on the day-ahead spot market in Germany leads to higher incentives for households to make use of their flexibility, which can - on the long run - have a positive effect on the over all energy system.

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Xin Wen, Marc Jaxa-Rozen, Evelina Trutnevyte

USING RETROSPECTIVE MODELING TO INFORM CHOICES IN DEVELOPING BOTTOM-UP ELECTRICITY SYSTEM MODELS

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Overview

Bottom-up, optimization-based electricity system models are commonly used to generate electricity scenarios for policy support, especially at a national level [1]. If modeled scenarios are consistently different from historical transitions [2], we can get insights from retrospective modeling on how to improve the models [3,4]. In literature, most studies focused on retrospective modeling for one country or region, but there are practically no such studies for multiple countries in parallel, where quantitative accuracy indicators and techniques inspired by statistical analysis would be especially helpful to draw insights from large historical datasets for many countries. The commonly used electricity system models typically incorporated endogenous features, such as elastic demand and technology learning effects [5,6]. However, the retrospective performance of the models with and without these endogenous features are barely evaluated. This would be useful in order to provide evidence on which model functions and versions to use for best accuracy performance.

Methods

In this study, we conduct a retrospective modeling analysis, using a technology-rich, perfect foresight, cost- optimization modeling framework D-EXPANSE, incorporating price elasticity of demand and technology learning effect. For the first time, we retrospectively model national electricity sectors in 31 European countries over the 1990 – 2019 period [7]. First, multiple EXPANSE model versions are developed by setting up price elasticity and technology learning functionalities. Second, we compare the retrospective accuracy performance of multiple model versions for each country, aiming at quantifying the impact of endogenous functions on accuracy. The 34 model outputs, such as installed capacities or annual generations of various technologies, are assessed with five accuracy indicators: symmetric mean absolute percentage error, symmetric median absolute error, symmetric mean percentage error, root- mean-squared logarithmic error, and growth error [2] (Fig. 1). Finally, these quantified accuracy indicators of all model versions in each country are compared by applying statistical analysis methods.

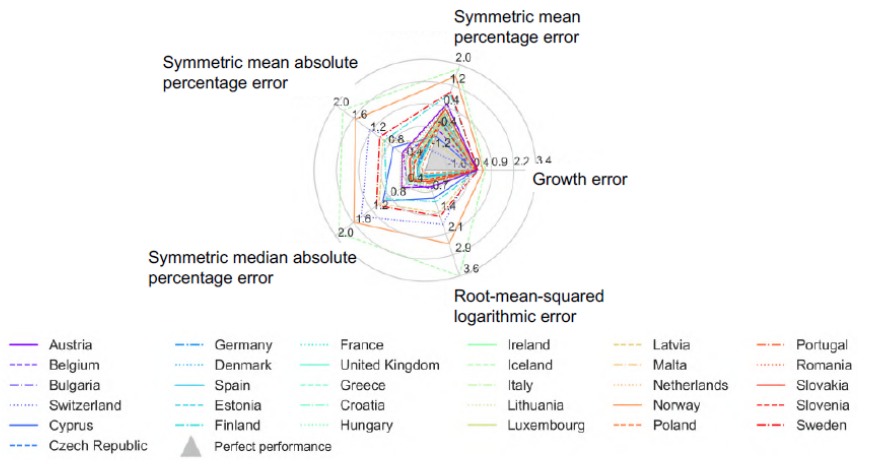

Figure 1. Demonstration of the retrospective evaluation of a basic EXPANSE version in modeling average annual CO_2 emissions using five accuracy indicators in 31 European countries in 1990–2019

Results

Based on the retrospective modeling and statistical analysis, we provide a comparison of different EXPANSE model versions in terms of accuracy performance in 31 European countries and gather new insights to what extent a country-specific combination of endogenous functions, depending on the specific domestic supply-demand equilibrium and technology deployment, will improve the model's accuracy the most. The results suggest that endogenous technology learning in cost-optimization models cannot always capture technology transitions or technology breakthroughs at a national level. Under-projection of renewable technologies are seen in many countries, especially solar PV. These under-projections of renewable technologies could be improved in some countries by setting the global learning effect. The elasticity of demand needs to be evaluated in country-specific occasions to get more accurate projections for some countries. By quantifying the model's accuracy at an annual time step, we also find that for certain technologies in some countries the deviations of the total technology mix from the real world are decreasing with time in the long term.

Conclusions

In this study, we present a retrospective modeling exercise with D-EXPANSE model for national electricity sectors in 31 European countries over the 1990–2019 period. We develop multiple model versions, with and without price elasticity of demand or technology learning functionalities, and use retrospective modeling for out-of-sample accuracy testing of these model versions. The results show which model versions have better accuracy performance when and, in this way, we gather first-of-the-kind evidence to forego subjectivity in the choice made by modelers when developing a new bottom-up model.

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Giovanni Bernardo, Francesco Marghella

ON THE POSSIBLE WAYS OUT OF THE POWER MARKET CONUNDRUM AFTER THE BIG PEAK FOR GAS IN EUROPE

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Overview

Starting from the second half of 2021, energy markets have experienced an extraordinary rise in fossil fuel prices caused initially by the recovery in energy demand triggered by the post-Covid growth path. However, the subsequent rally price has been intensified by the weaknesses of global supply chains exposed by the pandemic and even further in the first half of 2022 by the Russian invasion of Ukraine (Di Bella et al., 2022). The unprecedented gas price increase has influenced electricity prices, caused rising global inflation, and downsized the growth expectations of European economies (Albrizio et al. 2022). As a result, European citizens are now facing ever-higher energy bills as well as the economic issues posed by the covid pandemic. The discontent generated by the current crisis has led European governments to identify short-term emergency measures designed to cushion the negative effects of electricity price instability. Furthermore, the current situation has brought the rules of price formation in wholesale electricity markets back to the centre of the debate (Heussaff et al, 2022). In particular, the System Marginal Price (SMP) mechanism is showing some limitations with an over-remuneration of infra-marginal technologies and an increase in market volatility in a context of high fossil fuel price. Several alternatives to reform the market have been identified at the European level, among which the most relevant are the Iberian "Tope" (Pacce and Sanchez, 2022), the price cap on infra-marginal electricity sources proposed by the Italian Government (Sostegni-ter Law Decree 27/1/2022 n. 4 art.15) and by the European Commission (Regulation EU - 2022/1854), the pay-as-bid mechanism (PAB), the decoupling of the electricity market into two distinct markets (RES/NON-RES), as well as various mechanisms for ex-post extraction of infra-marginal rent. The aim of this paper is to evaluate the potential effects of some of these proposals on price formation mechanism by comparing *System Marginal Pricing* with two alternative configurations, which are *Two-markets* and *Pay-as-bid*.

Methods

To address this question, we include the three pricing mechanisms in the New Electricity Trends (NET) model (Cieplinski et al, 2021), a dynamic macrosimulation tool tailored to assess the feasibility of current energy and climate policy targets with a high penetration of RES. The model is hybrid with a bottom-up electricity module that interacts with a top-down macroeconomic model. NET model allows to consider an elasticity of demand with respect to price, which is the basis of the current trend of rapid decrease in consumption. At the same time, the installed capacity of each generation technology varies according to profitability in different market areas.
The different pricing mechanisms are modelled in this framework as follows. The SMP is determined by sorting in ascending order the marginal costs of each power generation plant and selecting the highest-priced unit scheduled to meet demand, which, in most cases, is gas-fired. To simulate the PAB, we assume a market in which the spot price is tied to the average generation cost of all technologies, weighted by the quantities offered. In other words, everyone receives what has been offered in the day-ahead marketplace. To rule out the possibility of strategic behaviour, the bidding prices of fossil power generation plants is equal to their respective marginal costs (fuel cost at spot market price + O&M + carbon emission permits) plus an exogenous mark-up, while RES operators bid at LCOEs plus an endogenous mark-up that has a direct relation with the gas price and inverse with respect to the share of renewable energy production. The *Two-markets* alternative is based on the idea of separating wholesale electricity markets in two sides, where fossil thermoelectric plants bid in a spot market with the SMP, while renewables operate in a forward market with long-term contracts (PPA). RES producers will receive a fixed remuneration for each MWh that is equal to the levelized cost (LCOE) differentiated by technology, size, and market area, plus a small margin.

To simplify the mechanism, the existing RES plants, in addition to any other incentive, can count on a price equal to the LCOE of 2021, while new plants will receive a price equal to the LCOE of the year plus a 5% markup. In addition to the three pricing options, we propose an analysis of the so-called "Tope" used in Spain and Portugal, where a maximum benchmark price has been fixed for natural gas used in thermoelectric generation. Furthermore, we add an impact simulation of the Regulation (EU) 2022/1854 for a temporary power price cap for infra-marginal generation technologies. The analysis of these solutions is limited to the year 2022 and aims to estimate the effect that the policies would have had on the Italian electricity market.
To take into account uncertainty, we conducted a sensitivity analysis of the gas market, proposing three price scenarios with a forecast time horizon between 2023 and 2027. The first scenario, called "Low" is representative of a rapid price decline toward the pre-crisis average, which was 20 €/MWh in the period between 2015 and 2019. The second scenario, called "High" assumes a further rise in gas price in 2023 that gradually falls back just above 50 €/MWh. The last scenario, "Medium", represents an average price of the previously described assumptions.

Results

Comparing the three hypotheses of price formation, we show that the total cost of electricity for households and businesses is always lower both in the case of *Pay-as-bid and Two-markets*. In the first case, when renewables cover an increasing part of electricity demand, competitive pressures between different technologies might decrease the trend in electricity prices – i.e., renewable energy policy paradox hypothesis (Cieplinski et al, 2021) - with negative effects on investments in RES (fig. 1). In the second case, long-term agreement to purchase clean energy should guarantee the profitability of renewable technologies, incentivizing investment in this sector only when a low gas price scenario is considered (fig. 1).
The *System Marginal Pricing* is the most expensive in terms of energy cost. However, it should be noted that a higher National Single Price (PUN) can ensure the profitability of renewable energy investments even in a low gas price scenario. Moreover, the price fluctuation between day and night should incentivize storage development due to the arbitrage that this technology can perform at different points of the day. In this respect, preliminary results show that PAB and TWOM options do not spur investments in storage technologies.
The last exercise aims to analyse, in the Italian case, the potential effects of two ceilings on gas input price and on power selling price (fig. 2). Under the assumption that no energy exports abroad are allowed, the former measure would have delivered savings of 23 billion euro in the case of cutting foreign electricity imports by half due to increased price competitiveness of domestic sources and 21 billion when zero import is assumed. A saving of 17 billion would have emerged in the latter case, representing a model of coordination between EU Member States.

Conclusions

Results highlight some of the strengths and weaknesses of the three price formation schemes. The *System Marginal Pricing*, in a high gas price scenario, is a mechanism that has negative repercussions on the economy, causing inflation and instability. To maintain this mechanism, sterilization measures of a fossil energy shock such as the Iberian exception of gas price cap used in the thermoelectric generation or the price ceiling for electricity must be implemented to obtain a more stable energy market and to reduce the economic instability at least in the short term. In a low gas price scenario, conversely, this mechanism ensures a price able to support the return on investment in renewables and encourages the expansion of the storage market.
As policy suggestions, the current price mechanism seems to be the most stable in the European context, while the other two show uncertainty in terms of RES and storage development. With the aim to stabilize the short-term prices, we also support the promotion of Contracts for Difference (CFDs) and PPAs between private parties (Meeus et al., 2022). Finally, streamlining the bureaucracy and speed up authorization process for new capacity is crucial to promote the energy transition, The Italian TSO, Terna, has calculated the requests for grid connection at over 300 GW, while less than 3 GW are to be installed in 2022.

Figure 1 – Decarbonization and price mechanisms

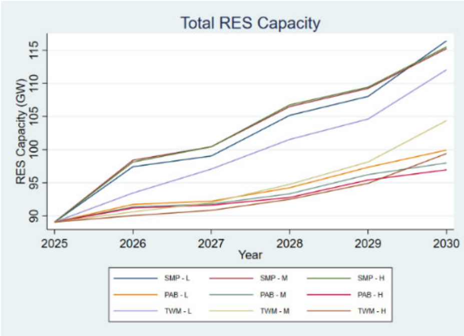
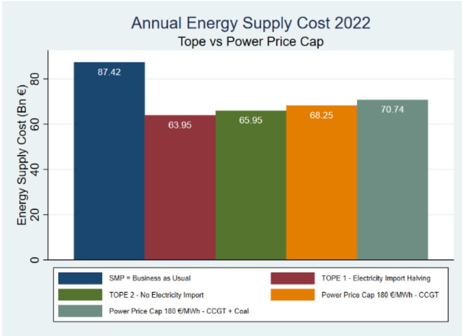


Figure 2 – Short-term measures impacts



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Giacomo Rispoli

ENERGY TRANSITION: H_2 AND CHEMICALS FROM WASTE, AN INNOVATIVE APPROACH

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Overview

One of the main reasons behind climate change issue is the disparity between characteristic time of carbon anthropic consumption and carbon natural sequestration paths. This unbalanced condition leads to an increase of CO2 content in the atmosphere up to 420 ppm [1] has to be balanced back. One of the most rational paths to perform in this aim is by promoting circularity in the fuel and chemicals production [2,3]. The waste to chemical process perfectly represents a ready-to-business technology and an economically feasible solution which is able to promote circularity also in the hydrogen production sector [4]. Generally, the waste to chemical technology is able to produce fuel with a lower carbon footprint by exploiting a carbon and hydrogen source which is commonly dispose of: waste. The proposed technology is able to convert the carbon and hydrogen contained into the waste which are the most difficult to be recovered or recycled: - Refuse Derived Fuel (RDF), which comes from the mechanical and biological treatments of Municipal Solid Waste (MSW); - Plasmix, which is the residual fraction of the recycling treatment of sorted plastic (about 40% in volume) [5].

Main content

The waste to chemical process is composed of five main sections.

1. High temperature gasification. This step is the core of the overall process. Since the combustible fraction of the waste is converted into syngas, meanwhile the inert fraction of the waste is melted – thanks to high temperature reached – and collected as a vitrified granulate material.
2. Syngas cleaning and storage. Syngas outcoming from gasification reactor is abruptly cooled from 1100°C to 90°C in order to freeze the composition and avoid the formation of toxic compounds. The cold syngas is sent to two scrubber and an electrostatic filter to perform a preliminary cleaning. The cleaned syngas in sent to a gas holder in order to control the potential fluctuation of flowrate.
3. Syngas compression and purification. Syngas from gas holder is compressed and purified through several steps including adsorbent beds, hydrolysis, and sulfur removal, in order to achieve a deep polish syngas which can not contaminate catalysts of the following step.
4. Syngas conditioning. According to the final product desired syngas composition must be adjusted to meet the synthesis requirements.
5. Final synthesis, the syngas can be separated to obtain hydrogen, or methanol, by catalytic synthesis, or ethanol, by biological fermentation, can be produced.

The waste to chemical scheme allows to recover both energetic and chemical contents included in non-recyclable waste. Indeed, the waste to chemical process rises as an alternative both to waste disposal method and conventional chemical production. Thus, by recovering the chemical content of waste to produce hydrogen, methanol or ethanol, we avoid resorting to fossil fuel application. Through an overall life cycle assessment (LCA), waste to chemical scheme allows to reduce carbon footprint chemical production: a CO2 saving higher than 70% is ensured. For this reason, methanol and ethanol produced from this scheme are eligible as renewable fuel to be added into fuel mixture in order to meet the target imposed by Renewable Energy Directive (RED). In particular, the methanol or ethanal fraction proportional to the fossil carbon contained in the waste is rated as "recycle carbon fuel" (RCF). According to RED, RCF is taken as renewable fuel which energetic content is countable for renewable target percentage. The fraction of methanol or ethanol corresponding to biogenic carbon contained in waste, is, still according to RED, eligible as advanced biofuel. Advanced biofuel fuel has a specific sub target in RED, thus accessing a surplus market valorization.

Till now carbon dioxide produced by waste conversion is not accounted in the European emission trading scheme (ETS), indeed conversion of waste is anyhow essential and better than dispose it of in landfill. Nevertheless, recycle must be encouraged. As known, mechanical recycle has technological and social limitations. Chemical recycle, of which waste to chemical process here introduced is one of the most representive and ready-to-built application, must be complementary to mechanical one, in order to meet a real circular economy. Within this background, the inclusion of waste conversion into ETS is expected. In this way, the waste to chemical scheme will be further favoured: gate fee related to waste will be higher, having to incorporate the price of emitted CO2 which will be paid by incinerator and WtE plants. This advantage will be even higher, in the case of Waste to chemical integrated with electrolysis scheme which allows to double the yield and lead to zero the CO2 emission from waste.

Conclusions

In summary, the advantage provided by waste to chemical processes is twofold: on the one hand, it constitutes an alternative to the conventional fossil-based fuels production; on the other hand, it functions as a novel, more efficient, and circular fashion to dispose of waste.
Such twofold feature is reflected on the economics. The gate-fee coming from the disposal of waste compensates for the additional costs which come with such an innovative, sophisticated and environmental-friendly system, rendering the final cost of the product competitive in respect to the cost of conventional products. Moreover, the H2 and other chemicals produced by this process can be considered as low carbon fuel thus accessing a separate increasing market related to sustainable fuels.

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Linda Cerana, Arturo Lorenzoni

A COST-BENEFIT ANALYSIS ON DIFFERENT ENERGY SCENARIOS FOR SARDINIA: METHANIZATION VERSUS ELECTRIFICATION, RENEWABLES, AND HYDROGEN

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Overview

Sardinia has been the subject of several methanization projects since the 1990s, none of which have been implemented but to a limited extent (distribution networks in some residential areas, currently powered by LPG or propane-air).
The debate over the island's energy future has heated up in recent years, with coal-fired power plants set to close by 2025, according to the National Energy and Climate Plan (PNIEC), and also fuelled by debates over the reactivation of the aluminium industrial hub in Portovesme. Between 2020 and 2021, the RSE conducted a two-phase study, commissioned by the energy regulator ARERA on behalf of the Ministry, aimed at evaluating several possible infrastructure options for the region's methanization through a cost-benefit analysis and with a time horizon of 2020– 2040.
However, the introduction of natural gas does not appear to be the path most consistent with the European Union's Green Deal commitment to net zero greenhouse gas emissions by 2050. A joint study by Politecnico di Milano and the University of Padua has proposed alternative scenarios for the evolution of the Sardinian energy system, calling for an energy transition toward decarbonization based on electrification and a greater use of the island's vast potential for renewable energy sources, which would be backed by storage systems and a hydrogen supply chain.
The goal of this study is to compare two possible alternative scenarios for the evolution of the Sardinian energy system, one based on methanization and the other on a direct shift to electrification and the use of hydrogen, using a Cost- Benefit Analysis.

Methods

Starting from the assumptions of the RSE and the studies done by the Politecnico and the University of Padua, the respective scenarios for the evolution of the Sardinian energy system (change in final consumption of energy vectors by sector, as well as evolution of the electricity and hydrogen generation and storage system) between 2020 and 2050 were defined, taking into account both the reactivation and the absence of reactivation of the aluminium supply chain in Portovesme.
In particular, for the methanization scenario, the BASE configuration developed by the RSE in Phase 2 of its study was used as a reference; this envisions methanization of the industrial and residential sectors only (for the latter, limited to the 18 areas with distribution networks already completed or in progress as of May 2021) and LNG supply via virtual pipeline (transport via LNG carriers from the Italian regasification terminals of Panigaglia and Livorno and delivery to Sardinia at the gas price of the Virtual Exchange Point (Punto di Scambio Virtuale)). Both scenarios include the decommissioning of coal-fired power plants by 2025, as well as meeting the minimum targets for end-use electrification and the installation of renewable energy plants derived from the National Climate and Energy Plan. As for the methanization scenario evaluated by RSE on a time horizon limited to 2040, we have assumed to reach 2050 with the same "decarbonized" configuration of the energy system developed by Politecnico.
The energy scenarios thus defined are compared using a Cost-Benefit Analysis with the "Sardinia energy system" as the perimeter and with the time horizon of 2020-2050. The following were specifically evaluated: (i) the costs of supplying energy vectors; (ii) the costs of CO_2 in ETSs for the thermoelectric and industrial sectors; (iii) the costs of environmental externalities (emissions of greenhouse gases and certain types of pollutants); (iv) the investment and operational costs for power generation, storage systems and hydrogen supply chain technologies; and (v) the costs of building and operating the methanization infrastructure.
In the analysis, the prices for energy commodities are derived from recent trends and are assumed constant over the analysis period 2020-2050.

However, a sensitivity analysis has been included to evaluate the results with different assumed prices of gas, electricity and ETSs, as these prices significantly affect the analysis and there is a fair amount of uncertainty about their future evolution, especially with the current unstable geopolitical situation.

Results

In the base case studied, with a gas price of €20/MWh, electricity traded with other Italian market areas at the Single National Price (PUN) value of €55/MWh, and an ETS carbon price of €83/ton, the scenario based on a direct switch to electrification and the use of hydrogen costs 2.12 billion euros more than the methanization scenario for the period of 2020-2050. This extra cost is due to: i) investment and operating costs for renewable power generation and storage systems, as well as hydrogen supply chain technologies (+1.50 Bn€ compared to the methanization scenario, in which installations - and thus costs - are concentrated in the last decade of the analysis period when CAPEX and OPEX will presumably be lower); ii) the cost of ETSs (+1.29 Bn€); (iii) environmental externalities (+1.26 Bn€); and (iv) the cost of purchasing energy vectors (+0.70 Bn€). These higher costs are due to the fact that in the methanization scenario the switch to natural gas allows for faster replacement of the more expensive and polluting fossil fuels currently used in Sardinia; furthermore, there is a large surplus of electricity that could be exported to the mainland, where the associated generation and environmental costs are then allocated, subtracting them from the expenses of Sardinia.
The electrification-based scenario, on the other hand, avoids the investment and operational costs of the infrastructure for LNG transport to Sardinia and the transport and distribution of gas on the island (-2.32 Bn€), as well as the costs of transitioning Sardinian domestic consumers to gas boilers and cooktops (-0.31 Bn€).
The cost difference between the two scenarios rises to +11.21 Bn€ if the aluminium supply chain is reactivated. What rises are primarily the costs of generation and storage technologies (+4.85 Bn€) and the purchase of energy vectors (+8.04 Bn€), owing firstly to the increased development of the hydrogen supply chain, through which the aluminium supply chain's need for electricity and low-temperature heat is assumed to be met, rather than through natural gas; and secondly to the increased import of electricity required to power electrolyzers.
For the different natural gas, electricity, and ETS price assumptions evaluated in the sensitivity analysis, without reactivation of the aluminium supply chain, the overall results differ as follows in terms of cost difference between the electrification-based scenario and the methanization scenario:

[1] natural gas at €80/MWh, electricity at €100/MWh, ETS at €83/ton: -1.45 Bn€;
[2] natural gas at €80/MWh, electricity at €150/MWh, and ETS at €83/ton: +1.78 Bn€;
[3] natural gas at €80/MWh, electricity valued at Sardinia's average cost of generation, thus varying over time and under different scenarios, ETS at €83/ton: -4.34 Bn€;
[4] natural gas at €80/MWh, electricity as in (iii), ETS ranging from €83/ton today to €145/ton in 2050: -4.08 Bn€;
[5] natural gas at €45/MWh, electricity as in (iii), ETS from €83/ton today to €145/ton in 2050: -0.54 Bn€.

In the event of the reactivation of the aluminium supply chain, the electrification- and hydrogen-based scenario turns out to be more costly in all cases (i)-(v), with an extra-cost ranging from +0.43 to +19.27 Bn€.

Conclusions

The results of the analysis show that, in the absence of the aluminium supply chain, there is an economic benefit ranging between -0.54 and -4.34 Bn€ in the electrification and hydrogen-based scenario compared to the methanization scenario, in all considered cases except for the case with gas at €20/MWh, electricity at €55/MWh and ETS at €83/ton (+2.12 Bn€) and the case with gas at €80/MWh, electricity at €150/MWh and ETS at €83/ton (+1.78 Bn€).
In the event of the reactivation of the aluminium industrial hub, the electrification and hydrogen-based scenario turns out to be more costly in all considered cases. This case, however, is unlikely, given the continued delays in production recovery plans in recent years and current energy prices.

The electrification- and hydrogen- scenario is also more consistent with decarbonization goals. The new scenarios of energy system development by 2030 (Fit-for-55) and 2040 (Distributed Energy and Global Ambition) developed at the European level and adapted to Italy by Terna and Snam pose even more challenging targets for electrification, the spread of renewables and the development of storage and the hydrogen supply chain. A methanization scenario appears anachronistic in this context. The rise of natural gas prices (which began in 2021 and is exacerbated by the Russian-Ukrainian conflict) could also significantly delay and limit the development of gas demand, risking the non-recovery of investments made for methanization, given climate neutrality targets for 2050.

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Negar Namazifard, Erik Delarue, Pieter Vingerhoets

INVESTMENT AND OPERATIONAL OPTIMIZATION FOR FUTURE HYDROGEN INFRASTRUCTURE: A BELGIAN CASE STUDY

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The European Union's green deal and European Climate law have set a target for the EU to become climate neutral by 2050. The transition to climate neutrality must be balanced with other priorities such as energy security to strengthen the EU's industry and energy system to create a level playing field in comparison with other countries outside the EU1. Following the recent REpowerEU plan2, hydrogen is a crucial candidate to reduce the emissions of the so-called hard-to-abate sectors that cannot be easily electrified. In particular, one can think of the industries where hydrogen can be used both as fuel and feedstock such as steel making, green fertilizer production, methanol synthesis and refineries. Belgium, the Netherlands, and North Rhine Westphalen (Germany) are currently the regions with the most concentrated hydrogen demand in Europe3. However, the supply of cheap and green electricity for commercially viable production of green hydrogen is scarce in these countries. Therefore, options for large-scale hydrogen import from regions with higher renewable potential or low carbon "blue" hydrogen production are currently being considered. To obtain crucial insights on the required capacities and investments for potential deployment of the hydrogen-related technologies and pipeline networks, one should technically and economically investigate the different processes for renewable hydrogen production, and develop various roadmaps to deliver these renewable molecules to the demand clusters.

Methods

In brief, an energy system investment and operational optimization model has been developed with high spatial resolution in the industrial clusters to analyze the Fluxys 2030 roadmap4 (see *Figure 1*) in Belgium for connecting the potential hydrogen production and import hubs to the demand nodes. Hypatia5 as an energy system modelling framework has been used following a linear programming technique with the objective function of minimizing the total discounted system cost to obtain the optimize future capacity of hydrogen network and hydrogen production technologies. In the first case study, the future non-energy hydrogen demand of industries located in the areas of Antwerp, Ghent and Mons has been considered based on the data taken from a project funded by European Commission called AidRES6 where the demand for hydrogen as potential future feedstock has been calculated based on the assumption of 55% reduction of CO_2 emissions in the steel, ammonia, methanol and refinery industries towards 2050. The case study starts form a greenfield in Belgium, i.e., without accounting for existing capacities and it is constrained by the network typology given by Fluxys.

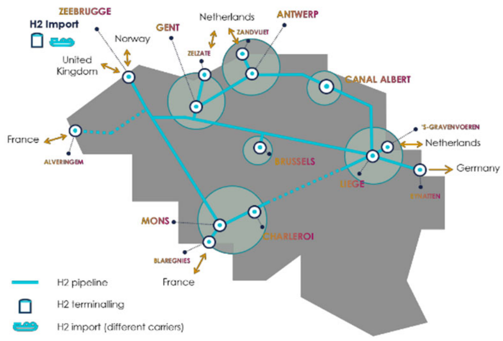

Figure 1- Fluxys roadmap for hydrogen backbone by 2030

The green hydrogen production routes from renewables connected to PEM electrolyzers have been included in all the regions modelled in this case study, considering their resource availability and renewable technology's (such as PV, onshore and offshore wind turbines) maximum technical potential. On the other hand, the blue hydrogen production has only been included in the Antwerp area, where there have been already some steam-methane reforming (SMR) capacities for grey hydrogen production.

Results

As can be noticed from the map shown below (see *Figure 2*), following the preliminary results obtained from the model, an open access backbone for hydrogen connecting the ports including Zeebrugge, Ghent and Antwerp would need to be installed in the north of Belgium by 2030, to connect to the industrial zones and neighboring countries. On the production side, next to inland solar PV panels and onshore wind turbines, one can think of dedicating a part of offshore wind capacity for green hydrogen production, bringing the produced electricity to the shore (Zeebrugge) and transporting the produced green hydrogen to the other industrial zones. It has been assumed that by 2030, there is low market interest for some of the chemical and petrochemical industries, glass, lime and cement production industries to be involved in the transition towards renewable hydrogen consumption. Therefore, based on this first case study, there would not been much required hydrogen pipeline capacity towards the south of the country connecting the Antwerp and Ghent area to Liege and alongside the Meuse river where these industries are mostly located. However, in the future cases with longer time horizons, these industries must be also included to obtain more realistic results for the hydrogen network all over the country.

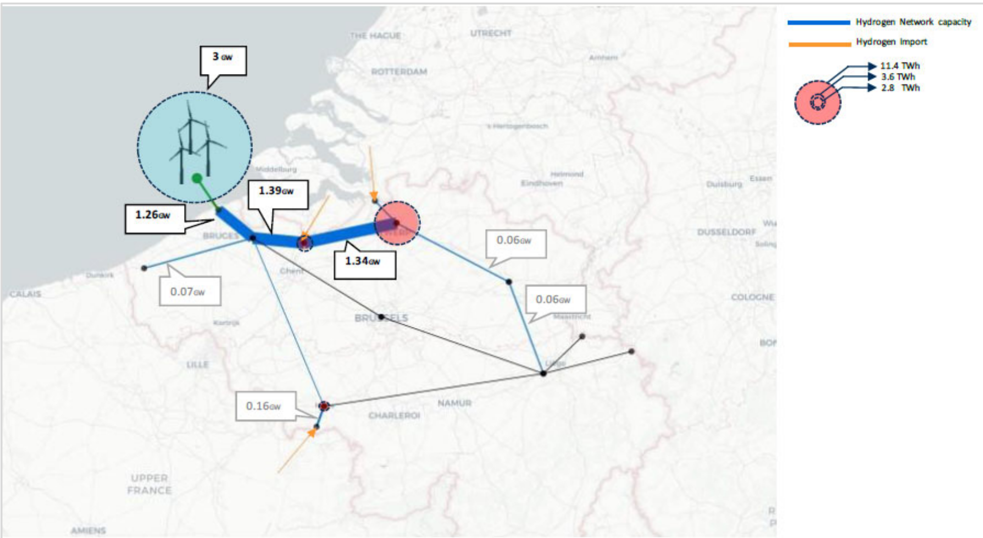

Figure 2- Preliminary techno-economic optimization results for hydrogen network capacity

Conclusions

The installment or refurbishment procedure of the underground pipeline infrastructure cannot follow a dynamic capacity expansion model. Therefore, it is important to follow a long-term vision and include all the potential demand clusters to avoid any underestimation in the required network capacity and therefore any possible future congestion in the pipelines. The results of the optimization model are highly dependent on the assumption and input parameters. Most of the input parameters of this case study as the main criteria of the model for choosing the most cost-effective hydrogen production and supply technologies are highly uncertain.

The most important uncertain parameters are including the future price of hydrogen imports, the electricity price for green hydrogen production and the natural gas price for blue hydrogen production. Therefore, global sensitivity analysis methods must be applied to give more realistic insights for various investment pathways.

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Matteo C. Romano, Angelo Lunghi, Gabriele Migliavacca

PROSPECTS OF E-FUELS

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E-fuels (or electro-fuels) are synthetic fuels typically produced by reducing CO_2 with green hydrogen from water electrolysis. A generic e-fuel production system is shown in Figure 1, that comprises: (i) systems for the production and supply of electricity, (ii) hydrogen production via water electrolysis; (iii) CO_2 capture from industrial or biogenic sources or from air; (iv) fuel synthesis process delivering the final e-product (e.g. methanol, Fischer-Tropsch hydrocarbons, methane) and (v) systems for energy (e.g. batteries) or gas (H2, CO_2) storage to manage the intermittency of renewable power generation.

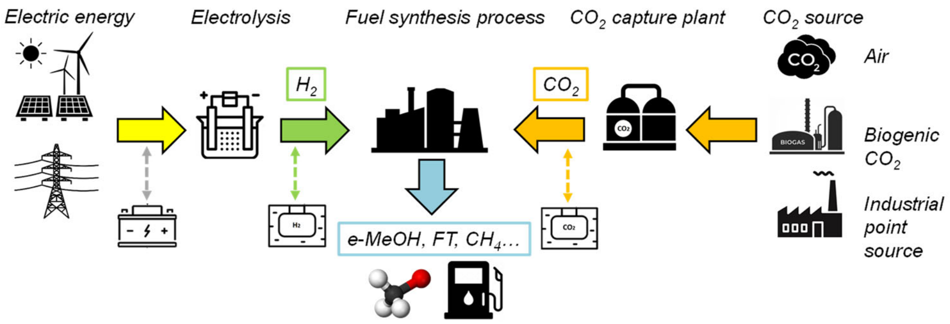

Figure 1- Generic e-fuel production system

The strengths of e-fuels are related to the possibility of long-term storage of electricity and to the existing infrastructure for transport, storage and use that allow intercontinental transport and seasonal storage at low cost. E-fuels also represent an alternative to biofuels, whose production is limited by the availability of sustainable biomass, for those sectors where direct electrification is challenging, such as shipping and aviation. According to the IEA "Net zero" scenario, in 2050 about 50% of the shipping fuel and 30% of the aviation fuel will be constituted by e-fuels.
In this talk, the prospects and potential of e-fuels are critically discussed, referring to key aspects to be considered in future e-fuels project such as: (i) energy efficiency, (ii) source of electricity, (iii) source of CO_2, (iv) production cost and international competition and (v) opportunities in enabling very high penetration of renewables in the electricity mix.
Also, an ongoing initiative involving Innovhub, Unem and Politecnico di Milano to promote the construction of a pilot plant will be described.

Sebastian Porter

CARBON FREE ENERGY: SYSTEM-LEVEL IMPACTS OF HOURLY CLEAN ELECTRICITY MARKETS, AND LESSONS FROM THE UK ON THEIR IMPLEMENTATION.

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Annually matched renewable electricity markets have historically played an important role in encouraging investment in renewables, through corporate clean electricity procurement based on the EU Guarantee of Origin (GO) clean electricity certificate system. However, in recent years, several key flaws have emerged in this system: it enables false claims of decarbonisation by allowing corporates to claim to be consuming clean energy at hours when it is not being produced, and because of this it stymies investment in renewables that cover hours of the day when clean energy is scarce.

Moving to a more granular GO system based on hourly matching of renewables production to consumption may solve these issues. According to modelling of US electricity markets by Princeton and EU electricity markets by TU Berlin, the intra-day price signal created by the use of hourly clean electricity certificates more accurately reflects the physical reality of the grid, and as such promotes investment into clean energy resources, or storage, that can cover hours of the day when the sun is not shining and the wind is not blowing, resulting in emissions reductions up to 120% greater than in an annually matched system.

However, the implementation of renewable electricity markets is not simple, and entails the move to a system where the availability of renewable electricity is tracked for the 8760 hours of the year. Based on experiences from the largest hourly renewable electricity market project in the world in the UK, several key lessons can be learned about the implementation of such markets. Consensus among a wide range of market stakeholders, including regulators, certificate registries, end-consumers, generators, and utilities is needed in order for such markets to be successful, and initially the hourly system must also be compatible with existing annual accounting systems, to avoid double counting.

Utilities emerge as key players in this transition as well, as they have the portfolio management and energy trading expertise to be well placed to manage any market risks that emerge from more granular renewable electricity markets.

Finally, new visualisation and allocation tools are needed in order to track such large volumes of power on such a more granular basis.

Johanna G.B. Rust

SECURITY AS A CHANGING PARAMETER/FACTOR IN FOREIGN ENERGY AND SECURITY POLICY AND THE IMPLEMENTATION: THE CASE OF THE EUROPEAN UNION AND PEOPLE´S REPUBLIC OF CHINA IN CENTRAL ASIA

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Keywords: Security, Energy Security, Conceptualization, Foreign Energy and Security Policy, Implementation Strategies in Third Countries

Overview

Power shifts, insecurity in energy supply and distribution, global supply chain reliability and other topics highlight a dynamic development on world markets and between countries. Recently, nothing is more pressing than discussing energy issues linked to climate change and security. Therefore, energy security is a highly prioritized agenda for not only the European Union (EU) but the People´s Republic of China (hereinafter China) as well. As net importers of energy and as two of four power blocks on the globe (besides the Russian Federation and the United States), China and the EU need to secure sufficient energy resources to keep their economies thriving. But what approaches and what kind of understanding of security is providing foreign energy security policy with ideas and concepts? In this research study, literature on security and energy security concepts and theories has been collected and qualitatively analysed. Many scientific contributions focusing on energy security provide conceptual frameworks based on both terms interlinked. So far, 'energy security' lacks an in-depth analysis of 'security' as a pre-analytical step. Originated from fossil fuel supply as a transboundary traded commodity of high importance, concepts of energy security changed in the past decades. New forms of energy and new infrastructure required a different understanding of energy security. Still, energy security is besides the domestic dimension a policy field of external relations and, therefore, important as a foreign policy topic.

As the consequences of climate change become more dramatic, the concept of energy security takes on new meaning. Energy as a basis for economic development fulfils central tasks in times of global reorganization. These bring with them renewed questions about security: whether it is a matter of obtaining fossil fuels, manufacturing mechanical components, or exchanging the latest research for future forms of energy – security of energy plays a role at various levels and in various forms. Energy sources, extraction, transportation, distribution, and usage has changed fundamentally in the past few decades. With so-called smart solutions based on digital connectivity, infrastructure and societies are becoming more vulnerable. Despite the usefulness for higher efficiencies and profitability through global supply chains and interconnection, "exposing operational technology to greater access and interconnectivity, also creates innumerable attack vectors"[1]. The energy sector is expanding in diversity since years what brings challenges to concrete energy security approaches and actors responsible for implementation. Dating back to the First and Second World War, the academic discipline of security and energy security was established in the United States (U.S.) and Great Britain not least to the question how to maintain a certain status quo of power distribution [2]. The nation state remains a central player in most security studies although the acknowledgment of non-state actors as increasing influences in the security connectivity mechanisms is undeniable. The EU´s approach toward Central Asia rests mainly on diplomatic relations accompanied by financial support and cooperation. China started its relations with the five Central Asian nations after the collapse of the Soviet Union when independence returned to a region that never was divided in geographic nation states.

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As a direct neighbour to three of five Central Asian nations, China established security relations within the Shanghai Cooperation Organization (SCO), on bilateral levels and emphasized from the beginning an economic cooperation to secure access to Central Asian resources. With the Belt and Road Initiative (BRI) the transnational cooperation was named and filled with initiatives especially in the infrastructure and energy sector. Both actors, the EU and China are net importers of energy and need the commodity for keeping the economies thriving. How to secure energy and the infrastructure involved remains an ever changing and important topic.

Methods

Energy security and security are two terms being used widely and in various contexts. In this research study, we look at the academic definition of ‘security’ first. After a qualitative literature review and identification of energy security concepts, the EU´s and China´s foreign energy and security policies toward Central Asia are discussed. Central Asia will serve as a case study to compare the implementation of both actor´s strategies in third countries. Expert interviews, conducted in 2021 and 2022 in Uzbekistan, Kazakhstan, Kyrgyzstan and Turkmenistan, will provide additional evidence. The aim is to identify first, to which extent the academic definition is part of foreign energy security policy of the EU and China. Since both actors prescribed in the beginning of the 2000s similar energy interests to the region of Central Asia, the case selected to analyse both approaches regarding the definition of security matches well. And secondly, to compare the EU´s and China´s implementation of their foreign energy security approaches toward Central Asia and to what extent they succeeded or if they faced challenges or failed.

This two-folded approach of theoretical analysis of the concept itself and the comparison within an actor’s policy as well as between both turned out to be useful in explaining differences in a successful implementation of foreign energy security policies. The case study, chosen to be Central Asia as a resource-rich region between Europe and China, supports testing the explanations that define how academic security understanding in politics cause increased or decreased levels of implementation of national interests in a cooperation and connectivity mechanism of the EU and China with third countries.

Results

If foreign energy and security policy is devised along criteria of national and regional security, it bears a promising potential to secure national energy security interests. Moreover, transnational cooperation and increased connectivity mechanisms can be observed between China and Central Asia. China formulated foreign policy strategies by prioritizing regional security led by mutual benefits and non-interference policy. China could successfully settle its border issues with Central Asian neighbours within the framework of the SCO and in bilateral relations. In addition, China expanded infrastructure networks such as pipelines and train routes to the Central Asian region always along natural resources extraction opportunities. Although China publicly followed a diplomatic and regional agenda, the reality showed severe concerns on the sustainability of Chinese investments in Central Asian nations. To conclude, China shows high congruence of its national security interests and what has been implemented in third countries, in Central Asian nations. The deviation is in formulations where official leaders constituted a friendly support which turned out not be all included or real in implementation. In case of the European Union, the congruence of academic security definitions in foreign energy security policy was high in the beginning 2000s. In a Memorandum of Understanding with the Republic of Kazakhstan, the EU underlined a common intent on promoting gas exports to Europe in 20063. In 2005, the EU appointed a Special Representative to the region of Central Asia and established a regular framework of high-level exchange. Nevertheless, the congruence of security understanding in foreign energy security policy decreased and reached a low point by the end of 2020. A trilateral cooperation of the EU and China in third countries, as described in official documents, is not supported by the results of the study.

Conclusions

The differences in the implementation of foreign energy security policy of the EU and China in Central Asia calls for attention. Engagement in third countries constitutes a main pillar in foreign policies of major powers such as the EU and China. It is interesting to watch closely how they implement their approaches and in a further process, analyse how they will encounter in third countries. Security and its academic understanding incorporated in foreign policy strategies is of importance for a successful implementation and sustainability of cooperation and connectivity mechanisms

RISKS IN THE ENERGY SYSTEM AND A MULTIVALUED MODAL LOGIC APPROACH TOIDENTIFY ADVERSE CYBER EVENTS

Ionut Purica , Professor, Executive Director of the Advisory Center for Energy and Environment, AOSR, Romania.

Content

- Risks for the energy system
- Climate
- Potential cyber
- Volatilities
- Network
- Climate
- Models

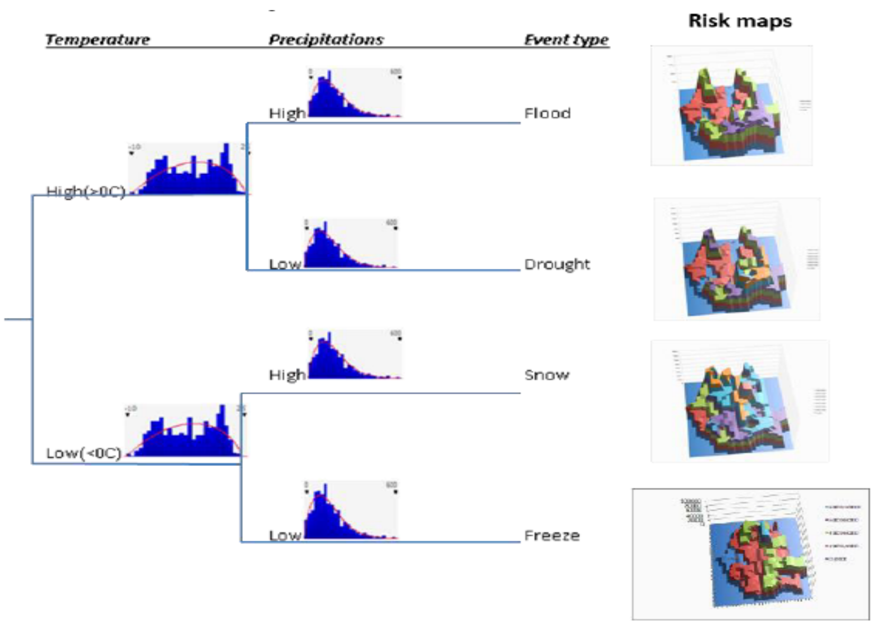
Risks for the energy system

Several risks are presented that undermine the energy system and comments are made on the potential use of combined AI (artificial intelligence) and BI (biological intelligence) in mitigating and adapting to these risks.

Climate

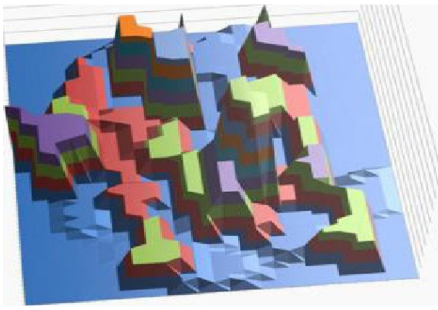
The climate risks are becoming more significant these last years due to the increase in the occurrence of climate change events. Looking at big data analysis on temperatures and precipitations in Romania's counties one may draw the climate change risk map of the country for various type of events: flood, drought, snow, and freezing, as shown below:

Event tree for Climate change events

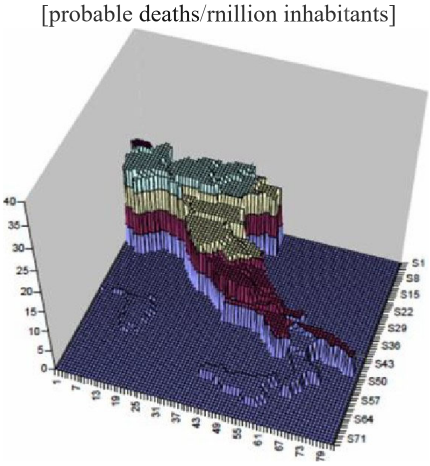


Moreover, there is a substantial impact on the critical infrastructures such as the gas network as shown below as a risk map and the power network as shown in pictures

Romania gas grid CC and rnechanical risk
[probable deaths/1000 cap]



Natural gas risk in Italy
[probable deaths/rnillion inhabitants]

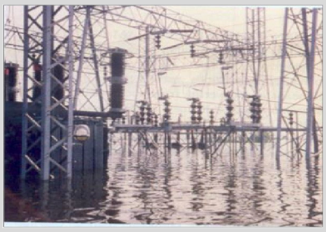


Critical infrastructure risk - hazards

Tower collapse (Shanghai)

Transformer after Eart hquake (Chile)

Station under flood (St. Louis, USA)

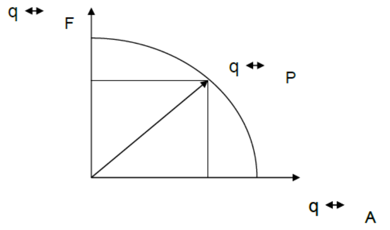


Terrorist attack (Colombia)

Source: IEEE Power & Energy nr.2

Cyber events

When looking at cyber related events one must try to prevent the occurrence of such events by accounting for the number of such events. To do this a nonbinary logic is more efficient in measuring the state of knowledge of the observer. Thus, the space of a logic values of possible events is defined where the truth and the false values are the usual ones in a binary logic. The formulae below describe the discernability of the observer in relation to the danger (truth) or lack of it (false) of a repeating cyber event.:



$$\mu^2_{q\leftrightarrow P} = \mu^2_{q\leftrightarrow A} + \mu^2_{q\leftrightarrow F}$$

Experiment	$q\leftrightarrow P$ / / $c\leftrightarrow A$	q – event c – condition
Observation	$n = n_A + n_F$	Repeating condition c n times will reszult in situations with q true or false

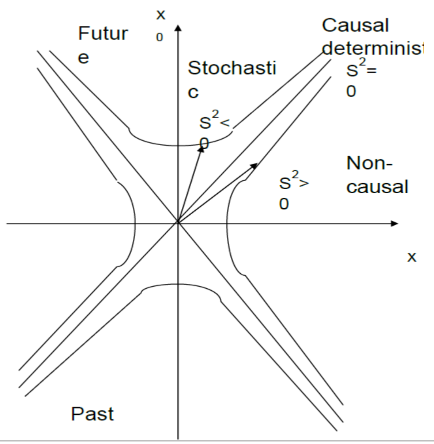
The state of knowledge of the observer and its the trajectory are resulting in the logic values space defined further on

$$x_0^2 = n = \mu^2_{c\leftrightarrow A} \qquad x_1^2 = n_A = \mu^2_{q\leftrightarrow A}$$

$$x_2^2 = n_F = \mu^2_{q\leftrightarrow F}$$

$$S^2 = -x_0^2 + x_1^2 + x_2^2$$

$$S^2 = -x_0^2 + x^2$$ pseudo Euclidian bi-dimensional (Minkovski) space



The pass from a state of knowledge to another is described by a Lorentz transform in the Minkovski space.
The evolution of the state of knowledge is associated with a'trajectory of knowledge'

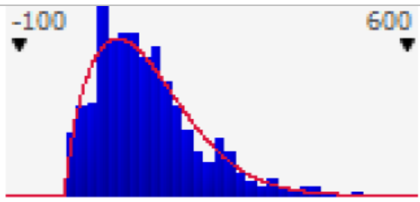
Conclusions on cyber events/attacks

The development of a new type of measure for the state of knowledge of the observer helps in determining the trend of various cyber events toward a state of risk leading to a possible attack.
New threats need better protection methods.

Volatilities
Elements of security

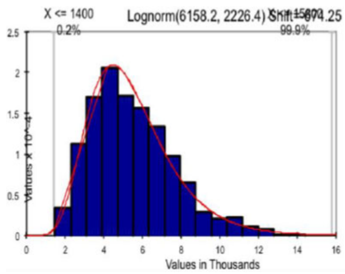
According to the Security strategy of the energy systems launched by the EU Commission in 2014 it is necessary to have a diversified portfolio of electrical energy generation technologies that ensures the coverage of situations when various types of risks manifest themselves. The same applies for gas interconnectors and for the climate change risks impact on critical infrastructures. Cyber security adds to the above risks.

The advent of more hydro, wind and PV technologies in the last years have increased the volatility of the power system. An evaluation of the need for reserve power due to such volatilities is given for Romania as shown below



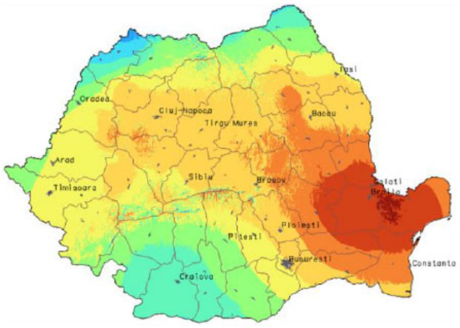
Precipitations

SD/Mean rain	0.6552731 1	hidro lake	
		TWh	16
		TWh lake	4.8
		h/year	8760
		exposure TWh	3.1453109 28
		power MW	359.05375 89



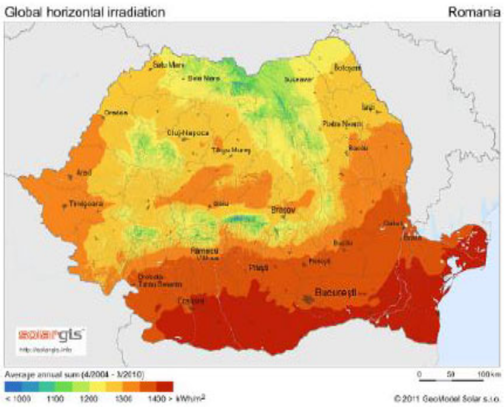
Danube

SD/Mean Danube	0.36153 4215			
		Needed security hydro run river		
		TWh	16	
		TWh run river	11.2	
		h/year	8760	
		exposur e TWh	4.04918 3203	
		power MW	462.235 5254	



Wind

SD/Mean wind	0.5	wind	
		TWh	3
		TWh wind	3
		h/year	8760
		exposure TWh	1.5
		power MW	171.23287 67



Photovoltaic

SD/Mean PV	0.6	PV	
		TWh	1
		TWh PV	1
		h/year	8760
		exposure TWh	0.6
		power MW	68.493150 68

Networks

It is very important to secure the resilience of the power and gas networks. One example is the attack of the NATO on the Serbian power system in 1999 that identified 5 critical points to produce a total black out. A cyber attack may also produce the same effect by targeting the critical points of a given power grid. Moreover on a different view point the lack of an North-South interconnector of gas is seriously affecting the security of supply in East European Union. The two figures below are good examples of the above statements.

Jeyhun I. Mikayilov, Anwar A. Gasim, Lester C. Hunt

CARBON DIOXIDE EMISSION BASELINE FORECASTS FOR SAUDI ARABIA USING THE STRUCTURAL TIME SERIES MODEL AND AUTOMETRICS

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Overview

To tackle the threat of climate change, countries around the world agreed to the Paris Agreement, which sets the aim to limit the global average temperature increase well below 2 degrees and potentially 1.5 degrees Celsius above pre- industrial levels (UNFCCC, 2015). Parties to the Paris Agreement are required to submit domestic climate plans containing mitigation measures, known as nationally determined contributions (NDCs), that reflect their ambitions and efforts to combat and respond to climate change. Each NDC, communicated at five-year intervals, must represent a progression compared to the previous one. Developed countries are expected to submit economy-wide absolute emission reduction targets, and developing countries are encouraged to move over time toward such targets (Fransen, 2021). As a developing country party to the Paris Agreement, in its first NDC submission in 2015, Saudi Arabia submitted a greenhouse gas (GHG), including carbon dioxide (CO_2), emissions avoidance target of 130 million tonnes (Mt) of CO_2 equivalent ($MtCO_2e$). Saudi Arabia updated its NDC in 2021, with a new target of reducing, avoiding, and removing emissions by 278 $MtCO_2e$ annually by 2030.

Saudi Arabia's NDC target has been set relative to an emissions baseline. Such targets are commonly referred to as 'baseline targets', and most of developing countries have chosen to adopt such targets, although the 2021 round of NDC updates saw some movement toward absolute targets, which are absolute emission reduction targets relative to a historic base year (UNFCCC, 2021; Fransen, 2021). Baseline targets require a baseline scenario, which is a reference projection that shows how emissions would evolve without any additional policy efforts, assuming the underlying policies and drivers extend into the future as they were in the past. The IPCC (2022) defines a baseline scenario as one that is "based on the assumption that no mitigation policies or measures will be implemented beyond those that are already in force and/or are legislated or planned to be adopted." Notably, the Saudi NDC does not disclose quantitative information about its baseline.

Methods

Developing baselines can be challenging, as projections can be very sensitive to the chosen methods, assumptions, and many other factors (e.g., financial crises, the coronavirus disease (COVID-19) pandemic, etc.). When it comes to methodologies, there are trade-offs between different methods for modelling and forecasting emissions. Statistical methods use historical time series data to produce a mathematical relationship that can then be used to generate baseline emission forecasts. With a univariate framework, statistical methods are used to model and forecast a single variable, such as total CO_2 emissions, while in a multivariate framework additional explanatory variables, such as gross domestic product (GDP), are added to the equation. While multivariate models may be more relevant for policy simulation projections, univariate models eliminate the need to make assumptions on the drivers. Univariate- based forecasts thus inherently assume that current trends, policies, and drivers will extend into the future, thereby creating a natural baseline projection.

Using Autometrics and the Structural Time Series Model (STSM), we estimate univariate models using the same data and estimation period, which we then use to generate forecasts of baseline CO_2 emissions in Saudi Arabia. Our focus is on modeling CO_2 emissions only, which account for the largest share of GHG emissions in Saudi Arabia. We first estimate statistically acceptable equations using both the Autometrics and STSM approaches, then use them to generate forecasts of CO_2 emissions.

Our projections are found to be consistent, pointing to their robustness. In 2030, the two predictions only differ by 15 Mt (671 vs. 686 Mt) while the difference grows to only 60 Mt by 2060 (941 vs. 999 Mt). We, therefore, set the average of both projections to be our baseline scenario for CO_2 emissions in Saudi Arabia.

Results

Our average baseline projection shows that CO_2 emissions in Saudi Arabia grow from 540 Mt in 2019 to 678 Mt by 2030, assuming trends, drivers, and policies in 2019 continued as is and no additional measures to curb emissions were undertaken. In its updated NDC, Saudi Arabia set a target to reduce, avoid, and remove GHG emissions by 278 $MtCO_2$ e annually by 2030 (Kingdom of Saudi Arabia, 2021). If we were to assume that 80% (which is roughly the current share) of this GHG emission reduction would be achieved through CO_2 emission reductions, our baseline projection suggests that the Kingdom would be aiming at an absolute level of CO_2 emissions of around 456 Mt in 2030. Our average baseline projection also reveals that CO_2 emissions in Saudi Arabia would grow to 970 Mt by 2060 if trends, drivers, and policies in 2019 continue for decades at the same rate, as unlikely as this may be given that in 2021 Saudi Arabia set a net-zero emissions target for 2060. Nevertheless, our baseline projection to 2060 gives some indication of the policy efforts required to meet Saudi Arabia's pledge to achieve net zero.

In the paper, we also highlight the challenges with forecasting CO_2 emissions. Choices made during the statistical modelling and forecasting, which might be perceived as minor, can considerably alter the trajectory of projected CO_2 emissions. Moreover, forecasting baseline CO_2 emissions in a country like Saudi Arabia, which is currently undergoing rapid social and economic reforms through Saudi Vision 2030, adds further complexity. Saudi Arabia's emissions grew rapidly since the 1980s but started declining from 2015 onwards following reforms. We show that if the Autometrics and STSM models were estimated using data that runs up to 2015 only, the forecasts generated from 2016 onwards would see baseline CO_2 emissions climb to 1,300-1,400 $MtCO_2$ by 2030 and over 8,000-12,000 $MtCO_2$ by 2060. These results demonstrate how adding four years of data points to the modelling (2016-2019) pulls the baseline forecasts down markedly. Given that the rapid pace of change and reform in Saudi Arabia is expected to continue over the coming years (Saudi Vision 2030, 2016), baseline emission forecasts for Saudi Arabia will need to be revisited and updated regularly.

Conclusions

In summary, this paper provides a baseline forecast in which CO_2 emissions rise to 678 million by 2030, the target year for Saudi Arabia's NDC. It also underscores the difficulties associated with baseline forecasting. Even when using a univariate framework, which focuses only on modeling the CO_2 emissions variable and naturally produces a baseline forecast without the need for assumptions on the growth of drivers such as GDP, choices and assumptions made during the univariate modeling exercise can alter the trajectory of CO_2 emissions. Therefore, practitioners need to use a logical, consistent, and scientific/non-judgmental approach when estimating models over past data and generating baseline forecasts. Finally, the rapid pace of change and reform in Saudi Arabia drastically alters the evolution of baseline CO_2 emissions. A baseline CO_2 forecast based on data that ended in 2015 rises to 1300-1400 million tonnes by 2030, compared to half of that for a baseline forecast based on data that ends in 2019. Therefore, baseline forecasts need to be regularly updated using new data, especially in countries like Saudi Arabia undergoing rapid changes. Given the economic transformation occurring in Saudi Arabia, future research could build on these univariate projections by adding explanatory variables to the econometric equations and exploring how different policy scenarios could influence the evolution of Saudi Arabia's emissions. Future research will also be needed to extend the analysis to other important GHGs, namely methane.

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SOCIAL CUES AND ELECTRICITY CONSUMPTION: EVIDENCE FROM A RANDOMIZED CONTROL TRIAL IN ARMENIA

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Overview

To avoid harmful climate effects the global greenhouse gas emissions need to be reduced and reach net zero by 2050 (Tsiropoulos, Nijs, Tarvydas, & Ruiz, 2020). As households represent over 30 percent of global energy consumption, reducing household energy consumption, and thus carbon emissions is an essential part of the decarbonization efforts. We study the effect of household energy decisions by providing information and social cues, also referred to as "nudges" (Leonard, 2008) in Armenia, a developing country. Developing countries are precisely the countries where the most rapid growth in energy consumption is observed, and many results and outcomes observed in the Western world proved to be hard to replicate in the context of developing countries (Henrich et al., 2010). The case of Armenia is also important as the energy consumption in Armenia is generally more sensitive towards income, as shown by the significant Granger causality between income level, and energy consumption in Armenia, while this relationship is insignificant for neighboring Azerbaijan, and Georgia (Kalyoncu et al., 2013).

In this study, we have collected the information on the energy consumption (electricity) in the Armenian households over the 6-months period. We asked the households the information regarding their electricity consumption, and their socio-economic characteristics.

The research focuses on people living in Yerevan, the capital of Armenia. To avoid possible interference by the type of agency problems that occur by renters, the research is focused exclusively on homeowners. A total of 300 participants were randomly and evenly distributed over 3 treatment groups. The randomization is done on the level of participants. In our treatments, we provide the households with peer comparison reports of their energy consumption and associated costs. The peer comparison reports reflect the average values of similar households.

The first group is the control group (C), the second group is the social comparison treatment (S). The housheolds in the second treatment are given feedback in the form of the average electrcity consumption of similar households' and the difference with their own electrcity consumption. The third treatment is the social comparison with a focus on monetary savings (SM). The households are given the same feedback as in group two (the average of similar households' consumption and the difference with their own consumption), but, in addition, the potential or realized monetary savings relative to the average of similar households' monetary expenditure.

Methods

We use a standard fixed effect regression to estimate the effects of our interventions on electricity consumption.

$$E_{it} = a_i + \tau_t + b_1 Info_{it} + b_2 InfoCost_{it} + \varepsilon_{it}$$

E_{it} - Electricity consumption by household i in period t.
$Info_{it}$ - The interaction term that indicates observations from the Information treatment group in the treatment period.
$InfoCost_{it}$ - The interaction term that indicates observations from the Information plus Cost treatment group in the treatment period.
a_i - Household fixed effects
τ_t - Month fixed effects
ε_{it} - The idiosyncratic error term

Results

We find that the households in both treatment groups exhibit reduced levels of energy consumption, especially among those households where the interviewed person was female. The effect becomes stronger, and more statistically significant for the subset of females with higher education.

Conclusions

One of the programs that are the most important/prevalent to lower energy consumption in the residential sector is the Demand Side Management (DSM) programs (Aydin et al., 2018). The DMS programs aim to lower the energy demand of households and thus reduce carbon emissions.
In this study, we implement an information provision experiment in Armenia. As demonstrated by the results of our information provision experiment there is a place for information provision policy interventions in Armenia, especially those targated at females with higher education.

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THE PRICE OF GAS IN EUROPE: TOWARD AN EPOCHAL CHANGE

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A dramatic year is coming to an end for the world and in particular for Europe, hit by an energy crisis that has no reference to the past.

The invasion of the Ukrainian Republic by Russia, engaged in a geopolitical design to reconquer the spaces of the former Soviet Union, has had profound consequences on the European Union's supply system, which has found itself in conditions of extreme insecurity and vulnerability, also because in recent years all the attention had focused on decarbonization policies to the point of prefiguring "Zero Emissions" scenarios to be implemented as soon as possible.

in the 2015-2018 period of moderate economic growth, the prices of gas imported into Europe on the basis of long-term contracts, widely representative of the market, had remained constantly below that of oil, guaranteeing its competitiveness and with a less volatile trend than that of oil and derivatives.

The outbreak of the pandemic at the beginning of 2019, with the collapse of the oil price motivated by the strong restrictions on mobility, had led to a temporary situation of disadvantage of gas

which had again turned into an advantage in the course of 2020 with the gradual recovery of economic activities.

In 2021 the scenario has changed radically and natural gas with a share equal to 24% of the total EU needs, reached at the end of an evolutionary process that began in the 80s, which has made it a leading source in all sectors of use outside the automotive sector.

In the first half of the year, the gas market had to face the first signs of a crisis linked to an unsatisfactory supply system from the point of view of security and diversification of supplies. In recent years, domestic production has fallen sharply, amounting to about 11.2% of total consumption, and the growth in imports, to the remaining 88.8%; in physical terms, 340 billion cubic meters.

In this situation, the European gas market began to experience price increases that set it on a very different path than in the past. Among the new elements is the increasing weight of the spot market on which the additional demand has poured with the consequence of bringing prices on this market above those of long-term supply contracts. Previously, in times of low demand, spot prices were considerably lower than those of long-term contracts, which nevertheless always maintained a certain link with oil prices.

The turning point in trade policy but, in reality, in Russia's foreign policy, has taken place gradually limiting first gas flows directed to the spot market concentrated on the Dutch TTF HUB just when demand was also increasing to fill storage in view of the 2021-2022 winter season.

Subsequently, supplies to Europe and mainly to Germany through the Nord-Stream gas pipeline were progressively interrupted until a mysterious attack destroyed an underwater section of this vital infrastructure. The consequences of the conflict on the European gas market have been devastating with a very serious impact on economic activities and the rate of inflation.

A completely new situation that has marked a deep fracture with an unsustainable past to be replaced with a new supply model.

LNG has been the great protagonist of this change thanks to the first upgrading of receiving infrastructures in northern Europe and the full use of those located in Spain, Italy and France that will form the basis of a system that will have the Mediterranean as its center of gravity.

In other words, to achieve a stabilization of the market after a phase that will still be characterized by strong volatility that will affect the whole of 2023, it will be necessary that all the initiatives undertaken in this emergency period to create a new supply system based on LNG and a bigger role for the Mediterranean is implemented without delay.

In this scenario, we can assume an international gas price less fragmented than in the past between the main geographical areas and determined by the demand and supply of LNG that has all the characteristics of a global market commodity, not subject to discriminatory practices by a single country or by cartels of producers, as occurred in the past with OPEC for oil.

The LNG market already sees as the first producer's countries with market economies and governed by democracies, such as the USA and Australia, as well as Norway and Canada, and which will be joined by new players in Africa and the Middle East with enormous potential.

With the expansion of the supply of which there are all the prerequisites, gas prices will return to levels much lower than the current ones, but which will still have to be sufficient to ensure its competitiveness vis-à-vis oil and renewables.

This could be around 40-50 $/b as also envisaged in the basic assumptions of the World Energy Outlook of the International Energy Agency published a few days ago.

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FINANCIAL TRANSPARENCY AND CROSS-BORDER MERGERS AND ACQUISITIONS IN THE EXTRACTIVES INDUSTRIES

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Overview

This paper investigates the effect of a targeted transparency regulation on the cross-border mergers and acquisitions (M&A) activity of multinational extractive firms. Proponents of greater transparency in the extractive sector argue that financial transparency as a policy tool can help increase payments to host governments, mitigate the corruption prevalent in the sector, and generally help stakeholders better monitor corporate behavior. Over the past two decades, several important international transparency regulations have emerged. Inspired by the frequent observation of a negative association of wealth and resource abundance (Sachs and Warner, 1995, 1999) and the fact that revenues from natural resource extraction often represent the bulk of government income (Calder, 2014, p.2), the Extractive Industries Transparency Initiative (EITI) was founded. EITI member countries commit to publishing comprehensive information on the extractive sector and financial flows between governments and extracting firms. A central feature of the EITI is to bring together revenue data from host country governments and to verify the figures using audited data from extractive firms (Calder 2014, p.56). This mechanism is mainly designed to counterfeit illegal kickback payments from extractive firms to host country government officials.
To complement the EITI, the European Union (EU) and Canada adopted a transparency legislation requiring large multinational extractive firms to disclose key financial and tax information data disaggregated at the country- level in which the firms have activities, also better known as public Country-by-Country Reporting (public CbCR)[3]. Policymakers view this regulation as an important means of combating the pervasive corruption in the extractive industries (European Commission, 2013; OECD, 2014). The transparency regime introduces a new obligation for listed and large non-listed extractive firms to report payments to governments broken down by country and by project. The following information has be provided on an annual basis: production entitlements; taxes levied on the income, production or profits; royalties, dividends, signature, discovery and production bonuses; licence fees, rental fees, entry fees and other considerations for licences and/or concessions; payments for infrastructure improvements. The implementation of the regulation happened in a staggered way with different implementation dates for different countries between 2015 and 2017. Table 1 shows the general structure of public CbC-reports by illustrating parts of the CbCR of TotalEnergies in 2018.
We study the effect of public CbCR on firms' cross-border M&A activity as increasing transparency likely changes the cost-benefit equilibrium of venturing abroad. On the one hand, firms under the scope of public CbCR may benefit from being more transparent, e.g. due to lower costs of capital, and increase their investments abroad. On the other hand, disclosing firms may suffer from additional costs. Johannessen and Larsen (2016) find large negative effects of public CbCR on the firm value of extracting firms, suggesting that the transparency legislation is expected to indirectly impose additional costs via reduced tax evasion and avoidance possibilities and additional reputational costs imposed by stakeholders (Dyreng, Hoopes and Wilde, 2016; Eberhartinger, Speitmann and Sureth-Sloane, 2021). Furthermore, Rauter (2020) shows that public CbCR results in higher fiscal payments of extracting firms to host governments and lower marginal investments in host countries. Because of these ambiguous predictions, the direction of the effect of greater financial transparency on firms' cross-border M&A behavior is unclear ex-ante and therefore represents an empirical question.

[3] Chapter 10 of EU Accounting Directive (2013/34/EU)

To assess our main research question whether public CbCR changes firms' M&A behavior, we exploit the staggered implementation of the regulation in the EU and Canada and compare the number of cross-border M&A deals of disclosing versus non-disclosing firms in a difference-in-difference (DiD) design. The preliminary results of our main test show a negative and weakly significant reduction of cross-border acquisitions in some model specification. However, we find a more negative and strongly significant decline in cross-border acquisitions for large disclosing firms, suggesting that large multinational enterprises (MNEs), which are in the focus of media and regulatory attention are the most affected.

Methods

Our research design exploits the staggered implementation of the transparency regulation in the EEA and Canada and the fact that firms from all other countries do not fall under the scope of public CbCR. Accordingly, we compare the number of completed outbound M&A acquisitions of disclosing firms (treatment group) relative to non-disclosers (control group) over time in a difference-in-difference design. As illustrated in Figure 1, TotalEnergies serves as an example of the identification strategy. TotalEnergies, the global ultimate owner (GUO) entity, is headquartered in France and thus must dislcose public CbC reports of its worldwide activities for fiscal years 2016 onwards. ExxonMobile, headquartered in the United States, serves as an example for control firms as this firm does not fall under the disclosure regime.

Empirical strategy

Equation I shows the empirical DiD design of the main test.

$$(I) \quad M\&A\text{-}Deals_{it} = \beta_0 + \beta_1\, pCbCR * POST + \beta_k\, CONTROLS_{it} + \alpha_i + \gamma_t + \varepsilon_{it}$$

The depended variable M&A-Deals is the number of cross-border acquisitions of parent firm i in year t. pCbCR is an indicator variable taking unity if a firm is headquartered in the EAA or Canada and 0 otherwise. POST is an indicator variable taking unity for years when pCbCR legislation is effective and 0 otherwise. Our coefficient of interest is β1 measuring the effect of the transparency regulation on treated firms relative to a group of unaffected control firms. Further, we include firm-specific control variables to account for time-varying firm characteristics that might be correlated with M&A activity such as size, profitability, leverage, intangible assets, the effective tax rate and loss firms. Appendix A shows all variable definitions. Also, we include a set of firm (α) and year (γ) fixed effects. These dummy variables control for time-invariant firm-specific factors such as the language or legal system of the headquarter country and year specific events. Finally, ε represents the usual error term.

We apply two types of fixed effects models, taking into account that our dependent variable is count data in panel form that take non-negative integer values and is unlikely to be normally distributed. First, we estimate Equation

(I) using a Poisson fixed effects approach following Cameron and Trivedi (2013). In an alternative estimation, we

Data

Our empirical design focuses on the acquirer side and analyzes the outbound M&A behavior of firms that disclose CbC-reports relative to non-disclosing firms. We start the data collection and obtain M&A deal data from the Bureau van Dijk Zephyr data base and download all completed M&A transactions in the 2010-2019 period. We exclude prior years to avoid that effects of the financial crisis impact our results and end the sample period in the year before the outbreak of the COVID-19 pandemic. As public CbCR applies to all firms headquartered in the EEA and Canada, we match all acquirer firms with their respective global ultimate owner (GUO) and keep only consolidated financial statements, as public CbC reports are generally disclosed in the parent's consolidated financial statements. We then aggregate all M&A deals at the level of the GUO and merge this data with GUO financial statement and industry information from the Bureau van Dijk ORBIS database.

We define M&A deals as new acquisitions of M&A targets and thus exclude other deal types, e.g. changes in minority stakes or joint ventures.

Since this study focuses on the impact of financial transparency on new M&A investments, we also exclude M&A deals that include an acquisition increase and acquisitions of an unknown stake. Furthermore and consistent with pCbCR legislations, we only keep listed or large unlisted firms[4].
Finally, we restrict the sample to GUOs from the extractive industries with two-digit NAICS2017 codes "21" (oil and gas) and three-digit NAICS2017 codes "324" (mining) and limit the sample period to +- 3 years relative to the year when public CbCR was implemented for each disclosing firm. Our final sample consists of consists of 1,124 observations, corresponding to 399 cross-border acquisitions.
Table 1 shows descriptive statistics of the dependent and control variables for firm characteristics of the total sample. In line with prior studies, all independent variables except etr and loss are winsorized at the 1% and 99% levels to reduce the effect of outliers on our analyses. In line with the tax literature, etr is censored between 0 and 1.

Results

Table 2 shows results of our main test of Equation (I) estimated by a Poisson and Negative-binominal model for the complete sample of treatment and control firms. The results in the strictest specifications in columns (2) and (4) including control variables indicate a negative and weakly significant effect of cross-border acquisitions on treated firms relative to the control group. These results present evidence that increased financial transparency raised the costs of cross-border investments of extractive firms that must disclose CbC-reports and thus reduces their M&A activity abroad relative to a group of firms without the reporting obligation.
Recent studies suggest that the costs of financial transparency are unlikely distributed equally across disclosing firms (e.g. Dyreng, Hoopes and Wilde, 2016; Eberhartinger, Speitmann and Sureth-Sloane, 2021; Andreicovici, Hombach and Sellhorn, 2022). For instance, Andreicovici, Hombach and Sellhorn (2022) show that stock prices of firms with greater reputational risk react more negative to the announcement of new transparency rules as these firms are more vulnerable to public pressure.
Related to our study, we expect that large extractive firms with well-established brands will anticipate higher costs to financial transparency than smaller competitors that are less subject to public scrutiny. Consequently, larger firms may face higher costs and reduce their cross-border acquisitions more strongly. In order to test this expectation, we run our DiD estimation within the treatment firms only and split the group of CbCR disclosing firms into large and small firms according to the median of treatment firms' total assets. In line with the expectation that larger firm that reduce their cross-border M&A activity more strongly, table 3 reports a negative and significant coefficient of the interaction term in most model specifications. These results suggest that larger extractive firms that are in the focus of public attention, for instance by the media or activist NGO groups, are most affected by the transparency regime.

Conclusions

We study the effect of an increase of mandatory financial transparency on the cross-border M&A activity of multinational extractive firms. European and Canadian legislators require extractive firms to disclosure key financial information broken down at the country level to inform stakeholders about their global payments to host governments ('Public Country-by-Country Reporting'). Proponents of more transparency in the extractive sector argue that the disclosure helps to curb corruption, foster investor protection and eventually nudge firms towards socially desirable behavior triggered by higher public scrutiny. As a result of more public scrutiny, firms are expected to face higher costs that may change their investment behavior abroad.
In the analysis of this paper, we exploit the staggered implementation of public CbCR in Canada and the EEA and test the effects of higher financial transparency on the cross-border M&A activity in a difference-in- difference design. The preliminary results suggest a negative and statistically significant effect of public CbCR on cross-border M&A deals of disclosing firms relative to a group

[4] EEA and Canadian headquartered unlisted extractive firms fall under the transparency regime if they meet two of the following financial thresholds: they report at least € (C$) 20 million in assets, generated at least € (C$) 40 million in revenue and employed an average of at least 250 employees.

unaffected control firms. In additional tests, we show that the effect is centered around large disclosing firms, thus suggesting higher regulatory and reputational costs for these firms. In light of the recent decision of the European Union to extend public CbCR to large firms in all industries, our results are policy relevant as we inform regulators about potential spillover effects of mandatory financial transparency on foreign investments of affected firms.

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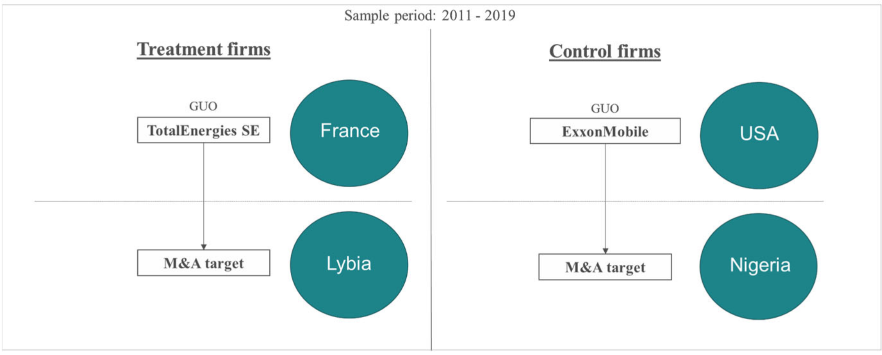
Figure 1 - Identification strategy



Note: This figure present the identification strategy. Our treatment firms are headquartered in Canada and EEA countries and must disclose public CbC-reports. Public CbCR legislation has been implemented in a staggered way between 2015-2017. In contrast, our control group consists of firms that are headquartered elsewhere and these firms do not fall under the disclosure regime

Table 1 - Form and structure of public Country-by-Country Reporting in the extractive sector

Panel A

9.3.1 Reporting by country and type of Payment

(in k$)	Taxes	Royalties	License fees	License bonus	Dividends	Infrastructure improvements	Production entitlements	Total of Payments
EUROPE AND CENTRAL ASIA	**1,063,539**	**-**	**25,154**	**799**	**-**	**10,442**	**100,560**	**1,200,494**
Bulgaria	-	-	169	-	-	-	-	169
Denmark	265,034	-	5,098	-	-	-	-	270,132
Greece	-	-	258	295	-	-	-	553
Italy	59	-	336	-	-	36	-	431
Kazakhstan	41,081	-	-	504	-	10,406	52,838	104,829
Netherlands	(37,600) [a]	-	1,271	-	-	-	-	(36,329)
Norway	567,885	-	7,567	-	-	-	-	575,452
Russia	20,382	-	74	-	-	-	47,722	68,178
United Kingdom	206,698	-	10,381	-	-	-	-	217,079
AFRICA	**3,139,947**	**-**	**56,002**	**152,318**	**6,188**	**66,343**	**2,274,817**	**5,695,615**
Angola	840,918	-	12,521	151,794	-	-	2,159,257	3,164,490
Côte d'Ivoire	-	-	1,590	-	-	-	-	1,590
Democratic Republic of the Congo	-	-	900	-	-	340	-	1,240
Gabon	224,365	-	6,008	425	6,188	21,749	-	258,735
Kenya	-	-	403	-	-	108	-	511
Mauritania	-	-	2,987	-	-	-	-	2,987
Mozambique	-	-	2,184	-	-	-	-	2,184
Namibia	-	-	105	-	-	-	-	105
Nigeria	1,372,888	-	3,523	-	-	44,146	111,132	1,531,689
Republic of the Congo	701,776	-	26,400	99	-	-	4,428	732,703
Senegal	-	-	2,396	-	-	-	-	2,396
South Africa	-	-	274	-	-	-	-	274
Uganda	-	-	(3,289) [b]	-	-	-	-	(3,289)

Panel B

9.3.2 Reporting of Payments by Project and by type of Payment, and by Government and by type of Payment

(in k$)	Taxes	Royalties	License fees	License bonus	Dividends	Infrastructure improvements	Production entitlements	Total of Payments
ALGERIA								
Payments per Project								
Tin Fouyé Tabankort	62,806[a]	-	-	-	-	-	186,293[b]	249,099
Timimoun	3,338	-	-	3,059	-	-	-	6,397
Groupement Berkine	331,342[c]	-	-	-	-	-	-	331,342
Tin Fouyé Tabankort II	13,754	-	311	-	-	-	-	14,065
Organisation Orhoud	66,728[d]	-	-	-	-	-	-	66,728
TOTAL	**477,968**	**-**	**311**	**3,059**	**-**	**-**	**186,293**	**667,631**
Payments per Government								
Direction Générale des Impôts, Direction des Grandes Entreprises c/o Sonatrach	460,876[e]	-	-	-	-	-	-	460,876
Direction Générale des Impôts, Direction des Grandes Entreprises	7,552	-	311	-	-	-	-	7,863
Agence Nationale pour Valorisation des Ressources en Hydrocarbures (ALNAFT)	9,540	-	-	-	-	-	-	9,540
Sonatrach	-	-	-	3,059	-	-	186,293[f]	189,352
TOTAL	**477,968**	**-**	**311**	**3,059**	**-**	**-**	**186,293**	**667,631**

Note: This table shows parts of an example public CbCR report from TotalEnergeis SE in 2018. Panel A shows financial information disaggregated at the county-level in which TotalEnergies has activities. Panel B shows this information broken down at the project and government agency level for Algeria. In total, Total's 2018 public CbCR consists of 17 pages and discloses detailed payments information for 45 countries.

Table 2 - Summary Statistics

Variables	Count	Mean	Sd	Min	Max	P25	P50	P75
ma_deals_cross_border	1,124	0.35	0.67	0.00	6.00	0.00	0.00	1.00
tot_as	1,124	19.79	3.24	12.80	24.87	17.24	19.98	22.54
prof	1,124	-0.23	0.67	-3.35	0.39	-0.22	-0.03	0.06
lev	1,124	0.23	0.21	0.00	0.94	0.03	0.21	0.35
intang_int	1,124	0.07	0.15	0.00	0.77	0.00	0.00	0.07
etr	1,124	0.17	0.24	0.00	1.00	0.00	0.04	0.26
loss	1,124	0.57	0.50	0.00	1.00	0.00	1.00	1.00

Table 2 - Public CbCR and cross-border M&A activity

	(1)	(2)	(3)	(4)
VARIABLES	Poisson	Poisson	Negative- Binominal	Negative- Binominal
pCbCR * POST	-0.260	-0.381*	-0.254	-0.372*
	(0.189)	(0.205)	(0.200)	(0.216)
tot_as		0.241*		0.119
		(0.123)		(0.0981)
prof		-0.154		-0.0903
		(0.160)		(0.157)
lev		-2.515***		-2.798***
		(0.711)		(0.758)
intang_int		-1.228		-0.654
		(0.830)		(0.772)
etr		-0.330		-0.190
		(0.315)		(0.328)
loss		-0.451**		-0.402**
		(0.184)		(0.193)
Constant			0.0131	-1.526
			(1.110)	(2.388)
Observations	1,307	1,124	1,307	1,124
Firm and year FE	yes	yes	yes	yes

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Note: This table shows regression results based on Equation (I). *M&A-Deals* is the number of cross-border acquisitions of parent firm i in year t. *pCbCR* is an indicator variable taking unity if a firm is headquartered in the EAA or Canada and 0 otherwise. POST is an indicator variable taking unity for years when pCbCR legislation is effective and 0 otherwise. Our coefficient of interest is $\beta 1$ measuring the effect of the transparency regulation on treated firms relative to a group of unaffected control firms. All control variables are defined in Appendix A.

Table 3- Public CbCR and cross-border M&A activity of small vs. large firms

VARIABLES	(1) Poisson	(2) Poisson	(3) Negative- Binominal	(4) Negative- Binominal
Large Firms*POST	-0.532**	-0.433	-0.621**	-0.544*
	(0.246)	(0.273)	(0.269)	(0.293)
tot_as		0.376**		0.134
		(0.190)		(0.132)
prof		-0.295		-0.136
		(0.247)		(0.235)
lev		-3.646***		-4.102***
		(1.146)		(1.185)
intang_int		-0.971		-0.641
		(1.155)		(1.084)
etr		-0.627		-0.383
		(0.443)		(0.468)
loss		-0.705***		-0.546**
		(0.249)		(0.266)
Constant			-0.186	-1.668
			(1.109)	(3.098)
Observations	712	573	712	573
Firm and year FE	yes	yes	yes	yes

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Note: This table shows regression results based on Equation (I) within the group of treated firms. *M&A-Deals* is the number of cross-border acquisitions of parent firm i in year t. *Large Firms* is an indicator variable taking unity if a firm is headquartered in the EAA or Canada with total assets above the median. The indicator takes 0 if a firm is headquartered in the EAA or Canada with total assets below the median. *POST* is an indicator variable taking unity for years when pCbCR legislation is effective and 0 otherwise. The coefficient of interest is *β1* measuring the effect of the transparency regulation on large treated firms relative to small treated firms. All control variables are defined in Appendix A

Appendix A
Variable definitions

Variable name	Definition and data source
ma_deals_cross_border	The absolute number of cross-border acqusitions (Zephyr)
tot_as	The natural logarithm of total assets, lagged by one period (Orbis)
prof	Profit/loss before tax divided by total assets, lagged by one period (Orbis)
lev	Non-current liabilities divided by total assets, lagged by one period (Orbis)
intang_int	Intangible assets divided by total assets, lagged by one period (Orbis)
etr	Tax expense divided by total assets, lagged by one period (Orbis)
loss	Indicator variable taking unity if profit/loss before tax is lower than 0, lagged by one period and 0 otherwise (Orbis)

Note: This table shows the variable definitions

Jorge Moreno, Donny Holaschutz, Altamiro Piña, Lucas Neira

CHALLENGES DETERMINING THE CAPACITY VALUE BY USING THE EFFECTIVE LOAD CARRYING CAPABILITY IN POWER SYSTEMS TRANSITIONING TO NET-ZERO CARBON EMISSIONS

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Overview

The rapid transformation of power systems will require greater efforts in planning and understanding of the security, flexibility and adequacy requirements of the system. The Effective Load Carrying Capability (ELCC) has been used in different markets to evaluate the contribution of generation facilities to the adequacy of the system. The approach and assumptions used to implement the ELCC has significant effects on the results.

The ELCC method was implemented using Plexos and applied to the Chilean context. Some of the challenges determining the capacity value using the ELCC in power systems transitioning to net-zero carbon emissions will be presented.

The following challenges will be discussed:

- The representativeness of the dispatch used to determine the ELCC, particularly at the maximum peak load that could be served by the installed generation considering different target LOLE and emerging flexibility challenges driven by the effect that variable renewable energy integration has in the operation of flexible generation assets.

- The development of long duration storage options and hybrid (renewable plus storage) resources to replace thermal assets that will be retired.

- The criteria used to assess the EFOR of thermoelectric facilities, since dispatch modes and failure rates of thermoelectric facilities are changing as power systems transition to net-zero carbon emission systems.

- The complexity and validation of the ELCC method in the context of power systems transitioning to net-zero carbon emissions.

Damien Dussaux, Stéphanie Monjon

SELLING UNDER OTHER SKIES WHEN ENERGY PRICES SKYROCKET: HOW DO THE COMPANIES ADAPT THEIR EXPORT STRATEGY WHEN ENERGY PRICES RISE?[5]

Damien Dussaux, OECD[6].
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Abstract

The prospect of higher carbon taxation leading but also recent jump in energy prices raise concerns that these policies could hinder the ability of domestic industry to compete in export markets, especially for energy-intensive sectors. This paper investigates the impact of a change in energy prices on export patterns of manufacturing firms using a large panel of French firms observed from 2001 to 2015. The identification strategy uses a fixed weight energy price index as a shift-share instrumental variable for the average energy cost. For the average firm we find that a 10% increase in the energy cost is associated with a 3.6% decrease in total export value, a 2.7% decrease in the number of export destinations, and a 2.3% increase in export prices. But there are substantial heterogeneities between firms facing a similar increase in energy costs. Lastly, the impact of an energy cost increase differs from one destination export to another.

Key words: Energy cost, price gap, export performance, extensive and intensive margins, OECD and non-OECD countries, low energy price countries.

[5] The project received financial support from PSL Research University for the project ENPRICE (The impact of energy prices in the manufacturing sector: an empirical study using firm-level data). We thank the Centre d'Accès Sécurisé aux Données (CASD) for the great work in providing high-quality confidential data. The access to the data was carried through the CASD dedicated to researchers authorized by the French comité du secret statistique. Finally, we thank Mathhieu Glachant and Fransesco Vona for useful remarks as well as all participants to presentations of earlier versions of this work at the EAERE Annual Conference 2019. Usual disclaimers apply.

[6] This paper should not be reported as representing the official views of the OECD or of its member countries. The opinions expressed and arguments employed are those of the authors

Cecilia Camporeale, Antonio Caputo, Emanuele Peschi

THE PULVIRUS PROJECT: A PILOT STUDY TO EVALUATE THE IMPACT OF COVID-19 ON THE ITALIAN ECONOMY AND ENERGY SYSTEM

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Overview

The Covid-19 pandemic has affected the whole world, triggering a global crisis that was particularly suffered in Italy due to a previous structural weakness.
To better understand its effects from various points of view, the PULVIRUS Project [1] was set up, an ambitious project resulting from the collaboration between various national research institutes (ENEA, Istituto Superiore di Sanità and Sistema Nazionale per la Protezione Ambientale and ISPRA), to investigate the controversial link between atmospheric pollution and the spread of the pandemic, the physical-chemical-biological interactions between atmospheric dust and viruses, and the effects of the 'lock-down' on atmospheric concentrations of pollutants and greenhouse gases.
As part of this project, it was possible to analyse the manner and force of impact that the implementation of measures to curb the spread of the coronavirus (COVID-19) had on the Italian economic, energy and environmental system.
The comparison of economic and energy consumption trends with the evolution of the epidemic containment measures adopted shows the existence of a clear correlation during the periods of greatest stringency of the measures, which was particularly evident during the total lockdown (11 March – 3 May 2020), where 45% of companies had to suspend their activities and more than 22% after a lockdown phase were able to resume their activities [2].

Methods

In this paper, we will analyse the impact caused by Covid from March 2020 to June 2021 on the Italian system.
In particular, the proposed work offers a snapshot of how the pandemic and the policy measures aimed at its containment have affected several aspects: economy, energy, and greenhouse gas emissions.
On the economic front, ample reference is made to ISTAT and Bank of Italy data, to grasp the evolution over time of the main economic variables (GDP, industrial production, etc.).
On the energy front, it has been considered the trend of the main drivers that explain the evolution of energy consumption, as recorded by the main institutes involved in the energy sectors (Terna for electricity, SNAM for natural gas, MiTE for oil consumption).

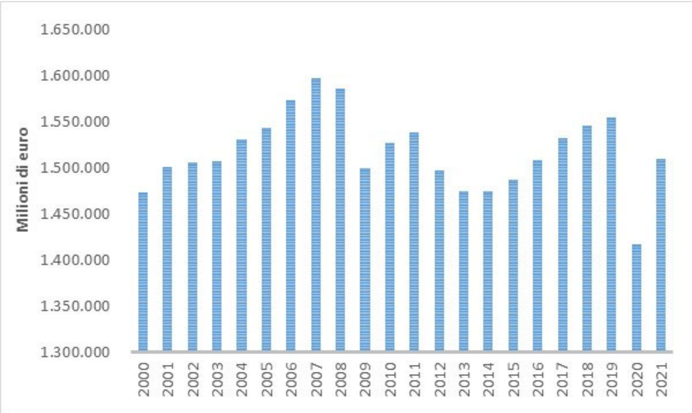
Results

Economy and Industrial Revenue

The global crisis triggered by the pandemic resulted in a drastic drop in GDP compared to 2019, and Italy, due to a previous structural weakness, was among the countries with the largest decrease in GDP. ISTAT data show that, for Italy, the pandemic crisis arrived while the recovery from the recession linked to the 2008 global economic crisis was still underway (Figure 1).
In 2009, there was a GDP contraction of 5.4%, the lowest value recorded from 1996 to 2009, followed by a rebound in the following year and a new contraction in 2012 and 2013, of -2.7% and -1.6%, respectively. From 2014, there was a three-year period of recovery, albeit slow, culminating in 2017 with +1.6%, which was followed by two years of positive but slight growth. In 2020, the outbreak of the Covid-19 pandemic crisis caused a deep collapse of the Italian economy, recording a contraction of -8.8%, the deepest in 25 years.

In the 2009/2008 crisis the contraction in Value Added (V.A.) was mainly due to the heavy fall in manufacturing industries (-18.5%), followed by smaller reductions in services and agriculture (-2.2% and -1.5%, respectively). In 2020, the decrease is the result of the combined contraction in the value added of all three sectors: agriculture (-4.7%), industry (-11.4%) and services (-8.5%)

Figure 1 – Trend of Value Added (million Euro, chain-linked volumes with reference year 2015)



Source: elaboration on ISTAT data

From a structural point of view, the gradual reduction of the weight of industrial activities to the benefit of the services sector is a long-standing path: as of 2013, the services sector stood at a 72% share of VA. However, three factors weighed heavily on the industrial sectors, especially in the lockdown period: the weight of the activities involved, the intensity of its foreign relations, and the fall in domestic demand [2]. As shown by the trend of the value added in the industrial sector on a quarterly basis in 2020, the fall was most marked in Q2, when it was most affected by the constraints on production activities required to contain the pandemic outbreak. The third quarter, on the other hand, recorded a sharp rebound due to the recovery in activity and production aimed at coping with the outstanding domestic and foreign orders that had accumulated in the first two quarters. The fourth quarter marked a new contraction, mostly related to the new pandemic wave, whose negative effects were limited, thanks to increased adherence to the vaccination campaign and measures to contain the pandemic.

In terms of industrial turnover, according to ISTAT data [3], the leather and oil sectors suffered the greatest contraction, with a reduction of up to 30% in total turnover compared to overall value in 2019. On the contrary, the food sector saw an increase and pharmaceuticals experienced only a slight contraction. However, when analysing these two results in detail, we can see that their average value is mainly driven by the foreign market, while domestic turnover has equally suffered from the economic crisis triggered by the pandemic.

<u>*Energy consumption*</u>

The trend in final energy consumption (Table 1) shows structural peculiarities for each sector and different sensitivity to the conditions that determine energy consumption, such as the economic crisis since 2008 and the 2020 lockdown.

Final energy consumption in 2020 shows a year-on-year reduction of 8.9 %.

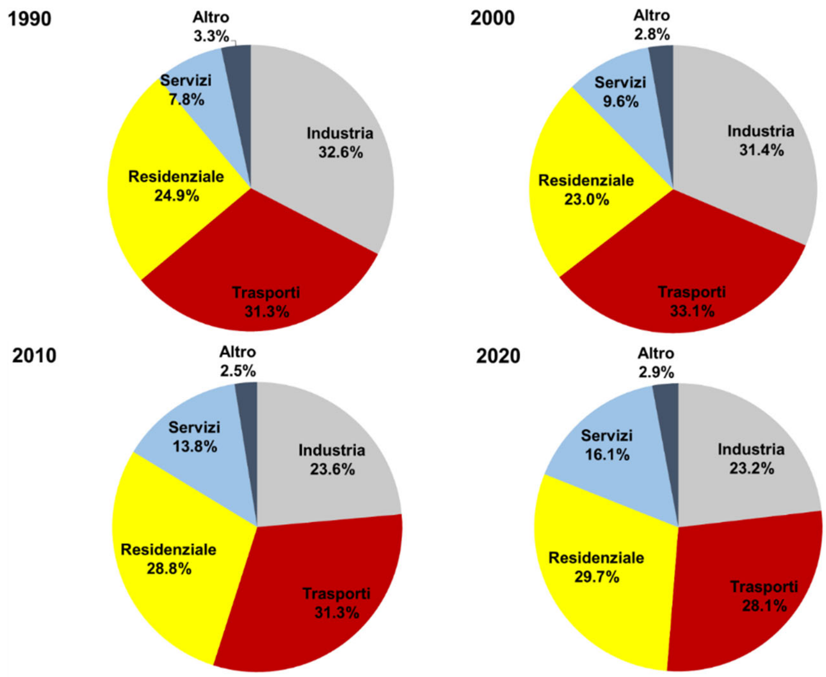
All sectors, except agriculture, show a decreasing consumption in 2020 compared to 2019, ranging from 19.2% in transport to 1.5% in residential. The sharp increase in consumption recorded for services from 2016 to 2017 is mainly due to the introduction of ambient heat produced by heat pumps in the energy balance, which was not present in the EUROSTAT energy balance until 2016. The final consumption of the residential sector also includes a small share of ambient heat from heat pumps, amounting to 95 ktoe in 2020 out of a total consumption from heat pumps of 2,475 ktoe.

Table 1 – Final energy consumption by sector (ktoe)

Sector	1990	1995	2000	2005	2010	2015	2016	2017	2018	2019	2020
Industry	34,1	33,9	37,6	37,2	29,0	24,9	25,1	24,9	24,7	24,9	23,9
Transport	32,7	36,6	39,7	41,8	38,6	36,4	35,8	34,5	35,6	35,9	29,0
Residential	26,1	26,3	27,6	33,9	35,4	32,5	32,2	32,9	31,9	31,1	30,7
Services	8,2	9,8	11,5	15,1	17,0	15,4	15,4	18,2	19,0	18,2	16,6
Agriculture	2,9	3,0	2,9	3,0	2,7	2,7	2,7	2,7	2,8	2,7	2,8
Fishing	0,2	0,2	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2	0,2
Other	0,4	0,6	0,2	0,2	0,2	0,1	0,2	0,1	0,1	0,1	0,0
Total	104,5	110,5	119,7	131,5	123,1	112,1	111,6	113,6	114,3	113,1	103,1

Source: Caputo A. (2022), Indicatori di efficienza e decarbonizzazione del sistema energetico nazionale e del settore elettrico, Rapporti 363/2022, ISPRA, Roma

Figure 2 – Share of final energy consumption by sector



Source: Caputo A. (2022), Indicatori di efficienza e decarbonizzazione del sistema energetico nazionale e del settore elettrico, Rapporti 363/2022, ISPRA, Roma

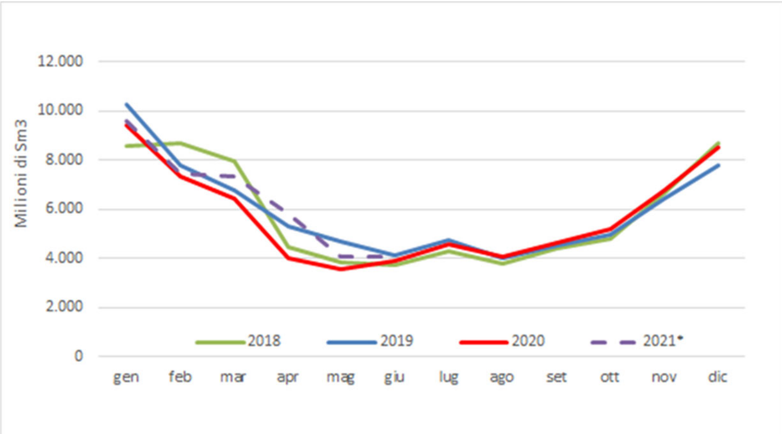
Consistent with the evolution of a mature economy, the structure of sectors in terms of energy consumption has changed considerably since the 1990s, as shown in Figure 2. Industry recorded a decline in its final consumption of 30% since 1990, while the 102.6% increase in services appears to be in sharp contrast. Services account for an increasing share of final consumption from 7.8% in 1990 to 16.1% in 2020, while the industry's share declines from 32.6% to 23.2% over the same period.
The trend of final consumption in the residential sector is quite variable due to the different climatic conditions influencing consumption. The average share of consumption in the other sectors (mainly agriculture and fishing) is just under 3%. The transport sector shows a decrease of 11.4%, mainly due to the decrease in consumption in 2020 during the lockdown period.

Natural gas consumption

The comparison of natural gas consumption trends in recent years (2018-2021; Figure 3) shows that while the curves overlap almost perfectly in the second half of the year, supported by winter demand for heating, the depth of the consumption curve in the first half of the year is different. In particular, the contraction of consumption in the March-June period is slightly more pronounced in 2020 than in previous years and much closer to the trend in 2018, the first year of contraction after the rise from the historic low reached in 2014, when the total value of gas consumed fell to 59.6 Gm^3.

In 2020, overall consumption decreased by 4.2% to 68.5 Gm^3. The contraction affected all sectors of use: - 5.7% compared to 2019 for the industrial sector; - 5.2% for the thermoelectric sector; - 2.7% for the civil sector. The gradual recovery since May has followed the gradual opening up of economic and social activities. It was only in July that consumption returned to normal levels, followed by the usual contraction in August due to the closures of the summer holiday period.

Figure 3 - Annual final consumption of natural gas: comparison years 2018-2021*



consumption in the first half of 2021

Source: Elaboration on Snam data

Electricity consumption

The overall contraction in electricity consumption in 2020 was -5% compared to electricity consumption in 2019, but the trend in monthly consumption in the first half of the year was much higher. Although in January 2020 there was already a -4% contraction in consumption compared to the same month of the previous year, due to mild temperatures (average monthly temperature of 17 °C) and one less working day, from March 2020 onwards that the contraction became particularly severe as a result of the pandemic emergency. With the start of the lockdown, as a containment measure for the spread of Covid-19, since 9 March 2020, electricity consumption plummeted by -10% compared to the same month of the previous year and continued its downward trend for the following months. In April 2020, amid the shutdown of almost the entire industrial system, electricity consumption contracted the most by -17%, followed in May by a -10% reduction in consumption compared to the same month of the previous year. The following months, although they recorded contractions compared to the same months of 2019, began to show signs of gradual recovery.

Starting from September 2020, Italian electricity consumption returned to previous values, thus recording a recovery in consumption (+0.1% compared to the same month in 2019); consumption in the following months and up to the end of the year was affected by the profound uncertainty linked to the dynamics of Covid-19 contagions, but marked a recovery in demand.

The restraining measures linked to the use of colours (red - orange - yellow) by individual regions had a more modest impact on consumption restraint than in March-May 2020.

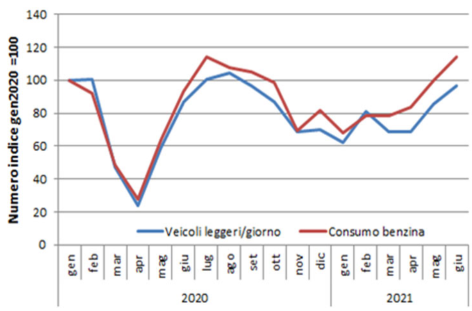
The first months of 2021 show a recovery in electricity consumption with an increase of +6.2% compared to the first four months of 2020, partially offsetting the contraction of -7.2% recorded for the same period in 2019. However, consumption in the first four months of 2021 remains -1.4% lower than in the first four months of 2019.
At the territorial level, the drop in electricity consumption for the March-May 2020 lockdown is evident in all the 6 zonal areas and corresponds to the first wave of contagion. From May to the end of September 2020, electricity consumption recovered and the number of infected people remained more or less constant. The relationship between electricity consumption and the second epidemic wave that began in October 2020 is different. In the North the variation was just -1.2% compared to the same month of the previous year, followed by -0.3% for the South and the Islands, while it remained stable in the Centre. In November, with the worsening of the indicators linked to the pandemic and the attribution of the colour red to several regions in the North (first and foremost Lombardy), electricity consumption contracted by -2.4%, while in the Centre the contraction was -0.8%.

The alternation of colours for the different regions that make up the zonal area justifies the recovery of consumption in all areas since December 2020.
With the gradual restarting of economic activities, production also recovers to pre-Covid values, in line with the trends of recent years.

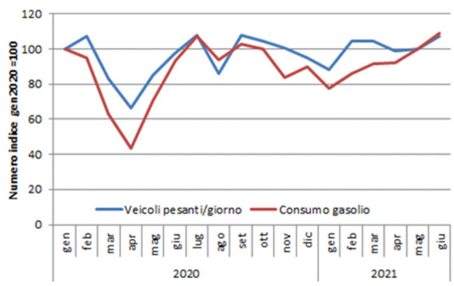
<u>*Petroleum product consumption*</u>
Covid-19 substantially affected oil product consumption throughout 2020 due to travel restrictions decreed to counter the spread of the virus.
Demand for petroleum products in Italy dropped by 15.7 % in 2020 compared to 2019, to just under 51 million tonnes consumed in total, reaching its lowest level in 20 years.
The national lockdown introduced in March 2020 led to a prolonged blockade of economic activities, but also of the social life and mobility of the population, causing a significant drop in Italian oil consumption.
In general, the reduction in consumption extends until the end of August 2020, while in the second half of 2020, a recovery can be seen, leading consumption to recover from contractions while remaining below pre-Covid levels, thanks to the easing of restrictive measures.
Petrol consumption, for example, was at its lowest in April 2020, at about 164,000 tonnes consumed, a consumption that is perfectly in line with the trend of traffic for light vehicles (cars and motor vehicles <3.5t) (Figure 5a)

Figure 1 – Trends in petrol and diesel consumption

a) comparison of petrol consumption and light vehicle traffic/day (index number Jan 2020=100)



b) comparison of diesel consumption and heavy vehicle traffic/day (index number Jan 2020=100)



Source: Elaboration on MiSE and Anas data

Similarly, to what has been seen for petrol consumption, diesel consumption in the transport sector, mostly related to the movement of goods, also suffered a reduction in the lockdown period, again following the trend of heavy vehicle traffic, which did suffer a contraction in the lockdown period, but decidedly less profound than that recorded for petrol.

Due to the adoption of stringent health protocols, which restricted the movement of citizens, both within the country and abroad, aviation fuel consumption was certainly one of the hardest hit, with more marked losses than other petroleum products.

GHG Emissions
An analysis of the time series of GHG emissions by sector shows that energy industries, as well as manufacturing and construction, recorded a very significant emission reduction. In fact, in 1990, the GHG share in total emissions for such sectors was 27% and 18% respectively, while in 2020 the shares were around 21% and 12%.
Transport and civil sectors show different patterns. Transport GHG emissions accounted for 20% in 1990, whereas in 2019 the share was 25%. Such increase is mainly related to the increasing passenger and freight mobility (+32% and +7% compared to 1990). By 2020, with the effect of the pandemic that drastically reduced demand for transport, especially for passengers, the sector's weight in total emissions decreased to 22%.
Emissions from the civil sector, composed of the residential and tertiary sectors, show a fluctuating trend throughout the historical series, mainly linked to the degree days that drive heating demand and consequent fuel consumption. A comparison of the sector's emissions in 1990 with 2020 shows that the relative share of the sector rises from 13% to about 19%. This increase is certainly linked to the expansion of the tertiary sector. Industrial processes show a strong decrease between 2005 and 2010 mainly due to the introduction of a new abatement technology in the production of adipic acid. The other sectors do not show significant changes throughout the time series and can be considered substantially stable.
When comparing the annual change in emissions from 2018 to 2019 and from 2019 to 2020, it is even clearer that the sector most affected by the lockdown phase is the transport sector, whose emissions decreased by almost 20% in 2020 compared to 2019, corresponding to a decreasing passenger and freight mobility around 36% and 10%, respectively. In 2020 traffic levels dropped below 1990 levels.
Emissions from the civil sector were virtually unchanged, indeed they increased slightly in the 2020 *vs* 2019, presumably due to the combined effect of increasing demand for heating in the residential sector during lockdown phases, with more consumption of natural gas, and decreasing demand in the service sector, where there is a significant contribution from heat pumps which consume electricity. Emissions for electricity production are accounted in the energy industries sector.

Conclusions

Although solid fuel consumption continued its downward trend that had already begun in 2015, 2020 showed a 26.5% reduction in consumption compared to the previous year, representing the highest annual reduction since 2015. The natural gas trend showed a contraction of 4.2%, affecting all sectors. In particular, the largest contractions were recorded in the industrial sector and the thermoelectric sector, both of which fell by more than 5%.
The consumption of electricity and petroleum products also contracted in 2020 by 5% and 14% respectively, following the lower demand due to the lockdown measures adopted to contain the epidemic. Indeed, the closure of businesses and services led to a sharp reduction in electricity demand that was not offset by the increase in domestic electricity consumption. The fall in petrol and diesel consumption was linked to travel restrictions. In this context, diesel consumption contracted less sharply due to the increased use of online shopping and therefore delivery services.
In terms of greenhouse gas emissions, the time series shows that the effects of the restrictive measures adopted in 2020 have further accelerated the reduction trend already underway in the industrial and energy sectors. With regard to the transport sector, it is worth noting that this sector recorded a contraction for the first time in a decade due to the restrictions on mobility.

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Geoffrey Ssebabi Mutumba

ELECTRICITY CONSUMPTION, FOREIGN DIRECT INVESTMENTS, CARBON DIOXIDE EMISSIONS AND ECONOMIC GROWTH IN UGANDA

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Abstract

Back ground

This paper investigates the causal relationship between electricity consumption, foreign direct investments (FDIs), carbon emissions and economic growth in the Uganda for the period 1990-2018.

Methods

It uses pooled mean group based autoregressive distributed lag (PMG- based ARDL) to deduce evidence of long run dynamic relationship between variables of study.

Results

Results indicate a long run relationship from electricity consumption to GDP. It is a significant positive relationship. Similarly, a positive relationship from CO_2 to GDP. While a positive relationship from FDI and GDP exists both in the short and long run. Both labour and real gross fixed capital formation have a positive and statistically significant impact on the GDP in the short run while electricity consumption is statistically insignificant

Conclusion

Our findings indicate that regional governments must increase investment in electricity markets so as to boost greater benefits from regional cooperation

Originality /Value

This is the first paper according to our knowledge to study dynamic causal relationships between

Key words: Electricity consumption, Carbon dioxide emissions, Foreign Direct Investments, Economic growth, Uganda.

Sania Wadud, Marc Gronwald

MEASURING MULTI-SCALE CONNECTEDNESS BETWEEN GREEN BONDS AND GREEN EQUITIES USING ATHICK PEN METHOD

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The recent transition of energy, concerns for climate change and sustainability through environmental-friendly projects has increased the popularity of green investments among policymakers, investors and scholars. In particular, since the issuance of the first green bond by the European Investment Bank (EIB) in 2007, there has been significant growth in the green bond market. This increasing trend is often referred to as a 'green bond boom' (Morgan Stanley, 2017). Concurrently, there has been a significant shift in the equity market due to investors' interest in eco-friendly investments. Furthermore, financial investors started to focus on changing their portfolios due to fewer diversification benefits in equity markets that are triggered by Global Financial Crisis. It is important to investigate how green bonds and other green investments/assets are integrated. This is because the information on their co-movement can assist in allocating an optimal portfolio.

Our theoretical basis for the integration between green bonds and equity relies on the theoretical link between bonds and the conventional stock market as suggested by Dean, Faff, and Loudon (2010). Dean, Faff, and Loudon (2010) find asymmetry in return and volatility spillover between the traditional bond and stock market. Our empirical strategy is motivated by Pham (2021) and Chatziantoniou et al. (2021) who use a cross–quantile dependence framework to investigate price connectedness between the green bond and green equity. While their model is based on a parametric approach, we use a non-parametric approach that is based on Thick Pen Transform (TPT) method.

We investigate return co-movement between the green bond and green equity using an approach called the 'Thick Pen Measure of Association (TPMA)' of Fryzlewicz and Oh (2011), which was later extended by Jach (2021) to 'Multi- thickness Thick Pen Measure of Association (MTTPMA)' to provide new insights on the changes in the co-movement dynamics. TPMA technique allows us to empirically examine co-dependencies between the green bond and equity for a given time scale or for a range of time scales, whereas the MTTPMA technique allows for the examination of codependencies across different time scales; that is, capturing a short-term component of a green bond series with long- term components of a green equity series, or the other way around.

Methods

We follow an extended data series similar to Pham (2021), where S&P Dow Jones green bond index is a proxy for the green bond market and NASDAQ OMX green economy stock index (Clean energy, green building, green transportation, global water, solar and wind). Apart from that we also include Bloomberg Barclays MSCI green bond index and the Solactive green bond index to verify whether the relationship changes varying the green bond index.

We follow Fryzlewicz and Oh (2011) and Jach (2021) to measure co-movements between the variables. We use a bivariate model. We calculate the Thick Pen Measure of Association (TPMA) of Fryzlewicz and Oh (2011) using[7]

$$\rho_t^\tau(X^{(1)}, X^{(2)}, \dots, X^{(K)}) = \frac{min_k\left(U_t^\tau(X^{(K)})\right) - \max_k\left(L_t^\tau(X^{(K)})\right)}{max_k\left(U_t^\tau(X^{(K)})\right) - \min_k\left(L_t^\tau(X^{(K)})\right)} \quad (1)$$

where, $X = (X_t)_{t-1}^{\tau}$ represents the time series of daily log returns; K = 2 which represents a single green bond index and a single green equity index; τ_i is the positive thickness parameter (scaler superscript) i.e. τ = 22 is month 1 data, τ = 126 is month 6 data and τ = 252 is year 1 data. We follow $L_t^\tau = \min(X_t, X_{t-1}, \dots, X_{t-\tau})$ shows lower boundaries of thickness and $U_{t\tau} = \max(X_t, X_{t-1}, \dots, X_{t-\tau})$ shows upper boundaries of thickness. The thick pen transform of X is denoted as follows

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[7] see Jach (2021) for details of the model

$$TP_{\tau_i}(X) = \{(L_t^{\tau_i}(X)U_t^{\tau_i}(X))_{t=1}^{T}\}_{i=1}^{n}$$

We calculate the multi-thickness Thick Pen Measure of Association (MTTPMA) of Fryzlewicz and Oh (2011) using

$$\rho_t^{(\tau^{(1)},\tau^{(2)},\ldots,\tau^{(K)})}\left(X^{(1)},X^{(2)},\ldots,X^{(K)}\right) = \frac{min_k\left(U_t^{\tau^{(K)}}(X^{(K)})\right) - \max_k\left(L_t^{\tau^{(K)}}(X^{(K)})\right)}{max_k\left(U_t^{\tau^{(K)}}(X^{(K)})\right) - \min_k\left(L_t^{\tau^{(K)}}(X^{(K)})\right)} \quad (2)$$

where scaler τ of Equation 1 is replaced by vector τ in *Equation 2*.

Results

The preliminary result suggests that there is an overall mixed association between green bonds and the green equity index in the long run than in the short run. However, this association varies because of some financial events and due to the type of green equity sub-index. Since the financial downturn in 2020 because of the Covid pandemic 19 periods, the overlaps between the green bond index and green equity index are low. In the long-term time scale, we find weak co- movement between the green bond index and clean focused energy index. This shows that issuing a green bond with long-term maturity will encourage clean-focused energy index investors to invest in green bonds. On the other hand, the overlaps between the green bond index and the green transportation index are higher in the long run. This suggests investing in the green bond will not be beneficial for investors in green transportation in the long term. We also find some asymmetry in return co-movement between the green bond and green equity in multi-scale connectedness (MTTPMA). In the majority of cases, the results show that in short term (i.e. in higher frequencies) co-movements are lower than in the longer term (i.e. in lesser frequencies) co-movement. However, these results vary in extremely volatile periods. We find similar results to Chatziantoniou et al. (2021), that the short-term and long-term co-movement do not co-move synchronously, rather it varies depending on financial and economic events.

Conclusions

The results provide new insights into the interdependence between the green bond index and green equity index uncovering some asymmetric effects of the short-term and long-term features of co-movement similar to the findings of Dean, Faff, and Loudon (2010). This technique is beneficial for diversifying the portfolio by combining green bonds and green equity (depending on sub-indices) in the short term and the long term. These results are beneficial for both short- term and long-term policy perspectives. Future research may divide the green bond index into sub-sectors to know which sub-sector co-moves with green investment and which does not.

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Papers

COUPLING EUROPEAN LONG-TERM ELECTRICITY MARKET WITH JOINT ENERGY AND TRANSMISSION RIGHT AUCTION – INSTITUTIONAL SETTING, MARKET MECHANISM AND GRID MODELLING COMPARISON BETWEEN NODAL PRICING AND FLOW BASED ZONAL PRICING

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1. Introduction

There is a stream of literature on European cross-border zonal market design, with a recent focus on the flow-based market coupling (FBMC). Ehrenman and Smeers conduct a comprehensive analysis about the potential barriers that European zonal market coupling may face at the beginning of market liberalization [1]. Neuhoff provides a quantitative comparison of nodal pricing and Net Transfer Capacity (NTC) based zonal pricing across several wind scenarios in the European electricity market [2]. Van den Berghe gives a good review of the flow-based market coupling process and parameters [3]. Purchala criticizes the zonal market design and advocates for the adoption of nodal pricing [4]. Felten et al analyse effects of different FBMC parameters and discuss the improvement made by European TSOs in recent years for the market coupling process. Their paper points out that fundamental shortcomings still exist in the FBMC process, namely with the ex-ante determination of zonal power transfer distribution factor (PTDF) by Generation shift key (GSK) estimation [5].

On the topic of long-term market development in Europe, De Hauteclocque offers a historical account of long-term transmission access prior to and during the liberalization process [6]. The Dena report gives an overview of current Power Purchase Agreement (PPA) practices and points out high market interest in PPAs [7]. On the development of financial transmission right in the zonal market, Spodniak uses historical data and calculates the economic expectation for Swedish and Finnish TSOs if they auction yearly and monthly financial transmission rights (FTRs). [8]. The main contribution of this research is to provide new angles on European cross- border market development with the introduction of the joint energy and transmission right auction in the long-term time frame. The compatibility of the current flow-based zonalpricing with JETRA implementation and the effectiveness of governance revolving around current market design are evaluated to guide future electricity market reform.

This research is unfolded with three dimensions. First, the challenges for the European electricity market are analysed and development of the long-term cross-border electricity markets is advocated. Tapping the potential of renewable energy resource complementarity over large geographical areas with cross-border markets create a more optimized andlow-cost system. In the wake of recent energy crisis, the importance of stable prices from long-term markets for consumers and instruments to hedge against spot market volatility is greater still. At the same time, certain contractual arrangements in long-term market such as PPAs in combination with physical or financial transmission rights can generate stable cash flows for renewable investors. The establishment of long-term cross-border markets that support both bilateral contracts and wholesale energy trade well in advance of delivery time is of vital importance.

Second, the joint energy and transmission right auction (JETRA) developed by O'Neill et al is proposed for long-term cross-border market development [9]. JETRA provides the possibility to auction energy, financial transmission rights and physical transmission rights simultaneously. The key characteristic of the joint auction is that transmission capacity limits are taken into account for hedging products allocated in the long-term market. This way, the auction is designed to keep price formation consistency between the long-term and spot markets. Another important characteristic is that the market clearing in JETRA is financial prior to the real time market. The market outcomes are liquidated after each round. Unlike long-term priority interconnection access implemented prior to liberalization, JETRA does not lock in physical interconnection capacity for right holders from the long-term horizon. Meanwhile, liquidated outcomes imply that auctions prior to real time do not interfere with physical dispatch to optimize the whole system according to real time constraints. The settlement rule is set up to link hedging products and spot market prices, enabling the network users that procures energy or transmission rights to financially hedge against the real-time prices or congestion risks.

Third, the flow-based market coupling mechanism currently implemented in the day-ahead market is carefully examined and adapted for JETRA under zonal pricing. The institutional settings and market mechanisms for the long-term auction are envisioned to follow the conventions of flow-based market coupling, while taking JETRA requirements into account in grid modelling. A case study based on a stylised network is used to illustrate the implementation of JETRA under nodal and zonal pricing. By comparing the grid modelling process and auctioning outcomes between nodal and zonal markets, the bottlenecks of flow- based zonal market design in supporting the joint auction are identified. In the long-term time frame, important aspects to examine are the role of higher uncertainties and the information asymmetry between market players and the system operator. We examine how inefficiencies from current institutional setups and flow-based market coupling methodology are amplified in the long-term time frame.
The organization of this paper is as shown in Figure 1. Section 2 discusses the historical development and challenges in the European cross-border electricity market, with a focus on the prospect of developing long-term market. Section 3 gives a description of the joint energy and transmission right auction, its spatial and temporal dimensions as well as institutional setting under nodal and zonal pricing. Section 4 sets up an illustrative example of a joint auction in the long-term, day-ahead and real time under nodal pricing. The joint auction outcome of the nodal market is used as a benchmark for that of zonal pricing. Section 5 gives a detailed description of adapting the current day-ahead flow-based market coupling mechanism into JETEA auction and institutional functions. Section 6 calculates the auction outcome under zonal pricing. Section 7 summarizes the observations and concludes.

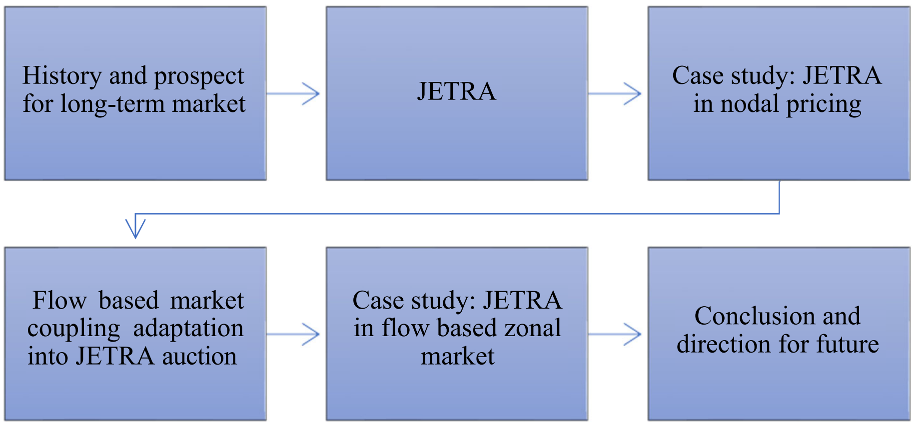

Figure 1 - Section organization chart

2. Long term electricity market in Europe

2.1 Long-term electricity market for renewable integration

An organized forward market or bilateral long-term contracts can be seen as important parts of the electricity market, complementing the competitive spot market. In this research, we refer to the time frame prior to the day-ahead as the forward market. In particular, the long-term market refers to organised markets or bilateral transactions more than one year ahead of electricity delivery, for example, 3 to 5 years prior to real time operation. The positive effects of long-term contracts for renewable integration can be multi-fold. For renewable generation plants, the high fixed investment costs and CAPEX dominant characteristics do not always encourage investment under the unstable spot market price. Long-term contracts, hedged against the volatility of the spot market, facilitate the investors to invest in high fixed cost technology and facilitate bank financing [6].

In the context of climate policy, a salient characteristic of bilateral long-term contracts is that they allow buyers to express preferences in terms of technology choice. This is seen as a driver for the emergence of renewable power purchase agreements (PPAs) for large industrial consumers who prefer to have the green electricity label. At the same time, energy intensive consumers or some retailers are also potential beneficiaries of cross-border renewable PPA as they search for low-cost green electricity at a stable price. Long-term contracts shield market participants from excessively high or low prices in the sport market.

In recent years, long-term PPAs have been on the rise within national borders in Europe [7]. There are mainly two types of PPA contracts: sleeves PPAs and financial PPAs. Under a sleeves PPA, two contracting parties can sign a long-term contract with a fixed quantity at fixed price. Grid fees are paid to the transmission system operator (TSO) for the use of the network. Under the form of financial PPA, two contracting parties can sign a purchase agreement with a fixed price without physically delivering electricity. However, there are no public examples in Europe for cross-border physical PPAs until 2020 [10].

2.2 Benefits of cross-border long-term market

As decarbonization is accelerated by the REPower package, EU legislation is expected to increase the 2030 renewable target from 40% to 45% [11]. A top-down set renewable target and growing demand for renewable electricity from consumers both call for a large scale of renewable generation investments in the most cost-efficient locations. Natural resources for developing renewable energy are not evenly distributed among Member States, so the development of a long-term market across borders is instrumental for a cost-efficient energy transition in Europe. Although the day-ahead and intra-day markets are coupled in Europe, the current energy crisis shows that consumers who are not hedged can be exposed to very volatile and high spot market prices. Furthermore, the lessons learned from the California crisis show that the lack of long-term contracts increases the risk of market power within a bidding zone [12]. Long-term contracts across borders can potentially benefit consumers in the national electricity market with new entries and potentially yield an anti-trust effect.
Long-term contracts are not uniform in terms of risks depending on the contracting parties' positions in the market and preferences. Therefore, different players may want to choose different risk hedging instruments for their cross-border trade. Not only is there a high interest in hedging the cross-border congestion risk financially or physically for bilateral long-term contracts, but also there are buyers who wish to procure energy that implicitly contains transmission access in the long-term time frame. It is important to make the wholesale energy transaction and bilateral contract compatible in the long-term market design.

2.3 **Historical account and current status in Europe: From long-term priority access for interconnections to the long-term transmission right challenges**

When liberalization started, a significant portion of interconnection capacity had been granted to former vertically integrated utilities in the form of long-term priority access. De Hauteclocque discusses the European perspective of the long-term priority access of interconnection capacity for electricity liberalization [13]. The Third Package has focused on mandating Third Party Access to provide level playing field to all market entrants. From a competition perspective, the European institutions view the prioritized long-term transmission access to interconnection capacity granted prior to liberalization as the monopolization of an essential facility and exerting an anti-competitive effect. Antitrust law, in particular, examines the methods used to grant prioritized long-term transmission access, in order to determine whether the methodology gives dominant players an unfair advantage in certain markets. The granting of access from the system operator to its affiliated arm within vertically integrated utilities raises concerns about the abuse of dominant position.

Therefore, the European solution has been a standard textbook market reform by developing a short-term market and coordinating transmission and generation in this time frame [14]. In particular, firstly explicit and then implicit auction have been used as interconnection congestion management method for a day-ahead market based on zonal pricing. Since market participants need to anticipate and match the bidding of transmission rights with their cross- border energy trade in explicit auctions, implicit auction has become the preferred method.

Commission Regulation 2016/1719 requires TSOs to develop harmonized rules for allocating physical transmission rights and financial transmission rights [15]. The regulation sets out rules for the development and cost allocation of long-term transmission rights. The allocation of cross-zonal capacity in the long-term time frame can be organized through explicit auctions. Long-term physical transmission rights and financial transmission rights can be procured by market players in auctions hosted by the Joint Auction Office (JAO) coordinated by TSOs[8] . Currently available long-term transmission rights for interconnections only cover one-year.
Will the implementation of joint explicit auctions of interconnection capacity in the long-term time frame bring an efficient cross-border long-term market? From a cost and risk allocation perspective, Beato points out that there are different incentives for TSOs and transmission users in the development of long-term transmission right products [16]. Unless TSOs are guaranteed cost recovery from regulators, they may be reluctant to increase the quantity and duration of long-term transmission rights. TSOs are required to ensure the firmness of the long-term transmission rights, otherwise they will have to compensate the right holders and face the risk this cost is not approved for reimbursement in the network tariff. A conflict of interest arises when traders want to acquire more transmission capacity in the long-term time frame and TSOs want to distribute it more equally across different time frames [17].

2.4 Can the transmission right auction across borders in the long-term time frame deliver the economic gains for Europe under zonal pricing?

History in PJM shows that when it was subject to zonal pricing, grid constraint costs were not well presented to market players faced with the flexibility to choose between the spot market and bilateral contracts. Many players switched from the spot market to bilateral contracts in view of the lower price of the latter, which contributed to increased congestion costs. In June 1997, due to high grid congestion, PJM had to administratively prohibit bilateral contracts to ensure grid reliability. This facilitated the transition from zonal to nodal pricing [18]. Another implication is that under zonal pricing in the long-term time frame, the common grid model needs to be calculated in a very conservative way to take into account higher uncertainties and the nature of the zonal model [19]. Consequently, much less cross-border long-term trade would be allowed if all bilateral contracts need to be feasible, which leads to lower network utilization in this time frame.
In this research, we attempt to move one step forward by implementing a centralized auction (JETRA) in the long-term cross-border market in conjunction with the current day-ahead market in a stylized network. One central question investigated in the study is to assess whether with energy and transmission rights simultaneously optimized in the long-term auction, the zonal market design in Europe delivers the same level of economic gains in comparison with those of nodal pricing.

3. Joint energy and transmission right auction model

3.1 JETRA characteristics and model formulation

A. Model characteristics
This research uses a central auction model proposed by O'Neill on the case studies to compare the economic efficiencies of auctioning transmission rights and energy under nodal pricing and zonal pricing [9]. The joint transmission right and energy auction model is selected because the model has several desirable features:

i. The auction mechanism takes a centralised view that aims to take into account different types of energy transactions while optimising the use of transmission network capacity. This joint model presents a way to include financial transmission rights and physical transmission rights (also called flow gate right in some literatures [20]) in the centralised auction process. The energy sale or purchase is brought into the forward market with implicit transmission access prior to the day-ahead market. Energy can be procured or sold in the wholesale market from long-term to real time
ii. The development of transmission rights as congestion hedging tools enables bilateral contracts at scale across borders such as cross-border PPAs. Market players can sign bilateral contracts to procure energy and hedge congestion cost risk by obtaining transmission rights in auctions.

[8] https://www.jao.eu/

The auction design also supports the network users' flexibility to choose financial transmission rights or physical transmission rights and allowing them to adjust positions in different time frames.

iii. In the multi-settlement rule, bid winners receive their revenues or make payment based on the accepted volumes determined in the previous auction and prices determined by bids in the current auction. This implies that market participants who procure energy contracts or transmission rights in the previous auction round will be paid the amount needed to obtain the same quantity of energy or transmission rights in the current auction. Therefore, the market player will always to be able to maintain their initial hedging quantity without additional costs to hedge against spot market price volatility

An interesting characteristic of the system operation is that in each round of forward market auctioning, the clearing outcome from the previous outcome, i.e., energy and transmission rights granted, is liquidated. This means that all financial positions held by the right holders are being bought back or sold back. The system operator can optimize network usage with operation conditions at real time dispatch. The anti-competitive problem of priority interconnection access does not apply to JETRA.

In this research, hedges are constructed by procuring energy sale/purchase contracts, financial transmission rights and physical transmission rights in the forward market. The forward market refers to the market spanning time frames prior to the day-ahead market. Market players can reconfigure rights and trade them in the secondary market. While the forward energy contract can be used to hedge against price risk in the spot market, transmission rights help market players hedge against congestion cost risk.

Overall, the wide range of instruments that cover energy and transmission products, the flexibility it gives to market players to choose different hedging mechanisms, and consistent market settlement rules across time frames makes the joint auction appealing in the development for a long-term electricity market.

B. Mathematical formulation

The mathematical formulation of the auction model can be summarized by the following formula. The auction model maximizes the value of accepted bids, including flow gate rights, point-to-point financial transmission rights and energy sale/purchase contracts. Auction optimization constraints include the load flow constraint and energy supply demand balance. Bidders need to include offer prices as well as lower and upper constraints for bidding quantities of energy sale/ purchase and transmission rights. In this study, only DC load flow constraints are used. There is no change in network typology in different time frames.

$$Max\ \boldsymbol{b_1 t_1} + \boldsymbol{b_2 t_2} + \boldsymbol{b_3 t_3} + \boldsymbol{b_g g} \quad (1)$$

$$\boldsymbol{\beta_1 t_1} + \boldsymbol{\beta_2 t_2} + \boldsymbol{\beta_3 t_3} + \boldsymbol{\beta_g g} \leq \boldsymbol{F} \quad (\boldsymbol{\mu}) \quad (2)$$

$$\boldsymbol{\alpha_2 t_2} + \boldsymbol{\tau g} = 0 \quad (\boldsymbol{\lambda}) \quad (3)$$

$$\boldsymbol{T_{LP}} \leq \boldsymbol{t_p} \leq \boldsymbol{T_{UP}}, p = 1, 2, 3; \boldsymbol{G_{Lp}} \leq \boldsymbol{g} \leq \boldsymbol{G_U} \quad (4)$$

Where:

$\boldsymbol{t_1}$ is a vector of the flow gate rights awarded to bidders. t_{1i} represents the ith bid by bidders to obtain rights and collect revenues from one or a portfolio of transmission element constraints. The term flow gate rights and physical transmission rights are interchangeably used in this research to refer to the rights for physical capacity on certain transmission element. Bidders can specify the highest and lowest amount with T_{1Lj} and T_{1Uj} respectively.

$\boldsymbol{t_2}$ represents a vector of point-to-point financial transmission right obligation awarded to bidders. t_{2j} represents the jth bid for the right to collect or to pay for nodal price differences between the designated node pairs in designated time period. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{2Lj} and T_{2Uj} respectively. The net injection for bid is defined $\alpha_{2j}t_{2j}$ and $\boldsymbol{\alpha_2}$ is defined as the row vector $\{\boldsymbol{\alpha}_{2j}\}$.

$\boldsymbol{t_3}$ is a vector of point-to-point financial transmission options. t_{3k} represents the kth bid for the option to collect nodal price difference between specified nodes. Bidder can specify the lowest and highest amount of the transmission rights they want to obtain with T_{3LK} and T_{3UK} respectively.

$\boldsymbol{g}$ is a vector of energy sale or purchase bids awarded to bidders. Lower and upper value of the bidder are given in the bid and represented by G_L and G_U.

$\boldsymbol{\beta_1}$, $\boldsymbol{\beta_2}$, $\boldsymbol{\beta_3}$, $\boldsymbol{\beta_g}$ is a vector of the transmission rights needed on each transmission element per unit of each bid type. It is also named the power transfer distribution factor per unit of transaction. $\beta_{1ih}t_{1i}$ is the transmission capacity needed on transmission element h with per unit value of ith bid for flow gate rights. $\beta_{2jh}t_{2j}$ is the transmission flow induced by per unit of financial transmission right bid t_{2j} on the transmission element h. $\beta_{3jh}t_{3j}$ is the transmission flow induced by per unit of financial transmission option bid t_{3j} on the transmission element h. We discuss below why financial transmission option is not used in this research. $\beta_g g$ represents the flow created on the transmission element by the energy purchase and sale bids.

F is a vector of the capacity limits of transmission network.

$\boldsymbol{\mu}$ is a vector of dual variables of the transmission constraints. For each transmission constraint, there is a dual that represent the shadow price for the transmission congestion.

$\boldsymbol{\tau}$ is a vector of ones.

$\boldsymbol{\lambda}$ is the marginal cost of meeting demand at hub node defined for the power transfer distribution factor calculation.

To ensure revenue adequacy, point to point FTR options $\boldsymbol{t_3}$ is limited to the sum of FGR with only positive PTDF values over the transmission elements. However, as the analysis of O'Neill et al shows, such point-to-point financial transmission option will likely result in lack of interest from market participants compared to FGR under the conservative assumption of positive PTDFs. A market player who chooses between FTR option and FGR pays exactly the same amount for these two products and receives less payback from FTR option [9]. Therefore, this type of rights is not included in the case study of the research.

C. JETRA implementation performance indices

Several indices are calculated to compare the outcomes between auctions under nodal and zonal pricing. It is important to note that the case study in Section 3 and Section 4 only uses one scenario. It is not an exhaustive scenario study and mainly serves to explain and showcase the causes of different performances while implementing JETRA. The first two indicators assess whether the market functions efficiently. The third indicator evaluates whether the hedging is effective for the market player participating in different markets of the joint auction.

i. Firstly, revenue adequacy for the system operator is assessed. The ability to reach revenue adequacy or come close to it is desirable in cross-border cooperation. Revenue adequacy is defined as the system operator's ability to pay the energy and transmission right holders from the collected surplus from selling and buying energy and rights. In literature, revenue adequacy refers to whether the system operator can collect enough congestion revenue to pay back the transmission right owners. This research expands the concept to cost recovery for the system operator from market-based mechanisms. Therefore, administrative procedures to socialize the cost gap across different jurisdictional areas can be avoided, in order to pay the bid winners.

ii. Secondly, the Generation Demand Shift Key (GDSK) metric used for each round of zonal market clearing is compared with theoretical optimal GDSK. The theoretical optimal GDSK leading to optimal dispatch with nodal information can be computed ex-post by comparing the auction outcome under nodal pricing with the base case generation and load pattern in different time frames. The GDSK used for grid modelling of the auction is the predicted nodal net changes per unit net position change. GDSK plays a determinant role in the interzonal transaction pattern and maximal allowed volume. The difference between the ex-ante predicted value and theoretical optimal value reflects the source of economic inefficiency for auctions under zonal pricing auctions and the inherent methodological challenge with the flow-based market coupling approach.

iii. Thirdly, the total net payment for the user at the demand node across different time frames is calculated in order to compare the dynamic economic efficiency of employing the congestion hedging instruments in the nodal and zonal markets. In the case study, we assume the costs of financial transmission rights and the energy purchase in different time frames are ultimately paid by the user, who represents demand at the major load node.

3.2 Spatial and temporal dimensions of the nodal and zonal market

3.2.1 Institutions and market process

a) Institution and market products under nodal pricing

The multi time frame joint transmission and energy auctioning model includes several types of products with locational pricing signal in a joint centralised auctioning: financial transmission rights, physical transmission rights and energy products in forward market and real time market. As O'Neill pointed out, Independent System Operator (ISO) responsible for market and network operation is at an advantageous position to host a joint energy and transmission right auction in forward market to include network constraint, generation, load, net import or export of each node [21]. In this research, JETRA under nodal pricing is organized by a system operator that optimizes market and network operation simultaneously. Consistent nodal grid representation is used in auctions of different time frames. The energy sale/purchase that includes transmission access is auctioned in the wholesale market. While bilateral contracts are conducted over the counter, the financial or physical transmission rights that guarantee the transmission access of bilateral contracts are auctioned.

Financial transmission rights provide the holders instrument to hedge against the uncertainties for locational price differences between injection and withdrawal nodes. The locational marginal price is the least cost of providing an incremental unit of electricity at a node without violating the transmission constraints. Financial transmission rights are settled based on the LMP differences between the node of withdrawal and the node of injection, thus from the user perspective holding the financial transmission rights would be sufficient to pay congestion charges based on nodal difference, regardless of how the power flows through the network. The allocation of financial transmission rights requires a central view of the network conditions from the system operator.
The physical transmission rights are paid based on the shadow price of specified transmission paths, so it requires the user to calculate accurately the usage of transmission paths of the desired transaction. To hedge the congestion risk for certain transaction, market players need to construct a portfolio of physical transmission rights over the transmission path. An example is given in Appendix to explain the use of FTR and PTR and how to make a portfolio of PTR with the equivalent hedging effect as FTR. Physical transmission right portfolio construction requires market players to compute transmission flows over the network and is technically more challenging. As O'Neill point out, FTR based on node pairs may experience lack of liquidity in secondary market. Since the usual congested links can be expected, offering of physical transmission rights can provide the possibility to hedge by a portfolio of physical transmission rights and inject more liquidity [9]. The physical transmission rights alone can be acquired without central auction as the physical limits of certain transmission elements can be determined separately by the owners of network assets.

b) Institution and market products under zonal pricing

The development of long-term market and effectiveness of its hedging instruments is the focus of this study. However, long-term market is not only about the long-term time frame. The payback of the energy and transmission rights procured by market participants in long-term auction are priced at later auction round. In this simplified case study to illustrate market logic, the long-term market is directly linked to day-ahead market coupling in the zonal model.

Day-ahead market coupling serves as the backbone of EU internal market and institutional arrangements are made revolving around the day-ahead market [14]. Under zonal pricing, the joint energy and transmission right auction follow the institutional designs revolving around current

European day-ahead market coupling. As Figure 2 shows, the long-term and day-ahead auctions can be cleared by power exchanges with zonal grid model input from TSOs, followed by redispatch and balancing markets organised by TSO.

Currently, cross-border intra-day market exists in Europe. Two forms of market mechanisms coexist in this time frame: auction and continuous trading. However, the interconnection capacity under the continuous trading is allocated on a first come, first served basis. There is no optimization of interconnection capacity in this design. Therefore, the intra-day market is not included in this research.

Redispatch is the activity conducted by the TSO after gate closure to dispatch up or dispatch down some generation or load, in order to alleviate network congestion from the short-term market schedule. In the case study, the schedules from day-ahead market clearing are submitted to the TSO to evaluate whether they are feasible with a nodal grid view. After gate closure, there is also balancing market in place to keep supply and demand balanced real time. As this research focuses on the effect of zonal network representation on redispatch cost and its implication on market design, balancing mechanism is not included in case study.

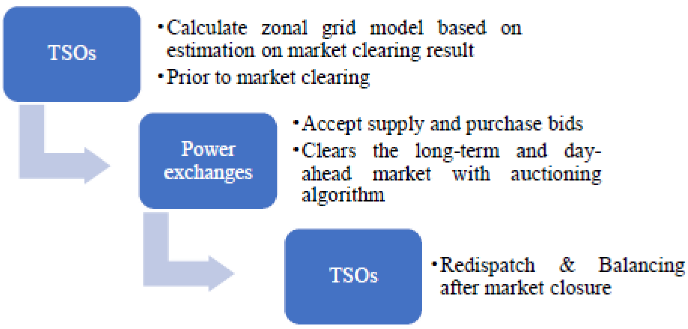

Figure 2 - Main process and institution in the European electricity market clearing

3.2.2 Multi-settlement rules

The financial schedules made in auctions prior to real time take into account the use of the network and can work with multi settlement rules for financial hedges. Market players pay to the system operator according to quantity and price determined in current auction. Holders of energy contract or transmission rights get paid according to quantity granted in prior auction times current auction price. To keep the rights from prior auction to current auction, market players can bid into the current round of auction by setting the lower and upper bound of the bid as the right quantity granted in previous round of auction.

Figure 3 shows how the multi settlement rules work for a market participant in a sequence of market time frames assumed in case study: long-term, day-ahead and real time auction. For instance, for a bidder who wins a 100 MWh of FTR between the specified locations in the long- term auction, the FTR bid winner pays to the SO the price determined in the long-term auction 5€/MWh multiplied by the allocated amount 100 MWh. In the long-term auction, this bidder pays the SO 500€ to obtain the rights. If the day-ahead price difference between the specified nodes turns to be 10€/MWh, the bid winner will be paid 1000 € for the 100 MWh of FTR. Assume the bidder as network user is interested to keep the 100 MWh FTR by bidding into day-ahead market with a lower and higher bound to be 100MWh, it will be charged 1000€ by the SO. In this example, the variation of price in the day-ahead market is hedged by the FTR obtained from long-term auction at lower cost.

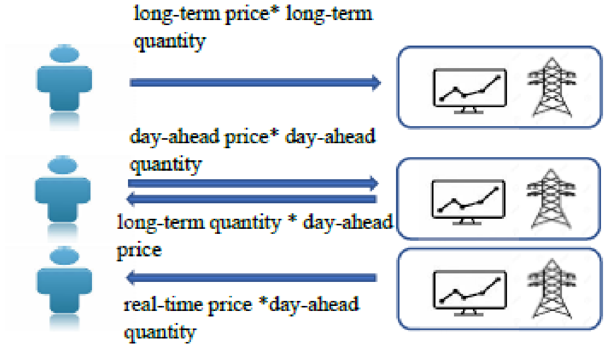

Figure 3:- Payment and receipt by the auction right holders under nodal pricing

In *Figure 4,* market time frames and involved institutions are depicted for zonal pricing at the top and nodal pricing at the bottom. Arrowed lines represent the auctions linked by the multi- settlement rules of the joint energy and transmission right auction. The lower part of the route depicts the markets in the case study linked by multi-settlement rules under nodal pricing: long- term, day-ahead and real-time. The bid winner who holds rights from the market in the left side of the arrowed line will be rewarded in the market time frame at the right side of the arrowed line. There is an integrated network and market operation by the independent system operator in the joint auctioning of energy and transmission right under nodal system.

The upper part of *Figure 4* shows that the multi-settlement rules link the long-term and day- ahead auction under zonal pricing. The system operator under zonal pricing for long-term and day-ahead auction can either be power exchange or TSO in the decentralised governance structure. After the gate closure of spot market, the redispatch and balancing are the sole responsibility of the TSOs who manage the grid and act as single buyer in the market. So naturally TSOs are at the better position to make settlement. After market closure, the term system operator in time frame refers to the TSOs only. The dashed lines indicate the multi- settlement rules do not apply in the time frame.

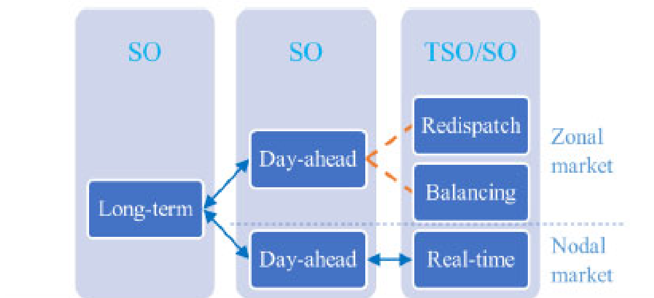

Figure 4 - Market time frames and responsible institutions under different pricing schemes

3.2.3. Financial schedule and physical dispatch

As shown by the case study in the section 4, the multi-settlement system creates a consistent breakdown of costs in different timeframes that rewards the deployment of hedging instruments for market players. The auctioning outcome is liquidated after each round prior to real time market. Liquidation implies the dispatch in these auctions are not physical commitments and thus not directly linked to actual use of the transmission network in real-time operation. Market participants can participate in the auctions with financial schedule, in order to hedge the real time price volatilities or congestion risk.

Only in real time market, the cleared bids are treated as physical commitments. Generation capability and bilateral contracts are taken as constraints for the real-time market under the JETRA model.

Therefore, the problem discussed in previous section, i.e prioritized long-term physical access to interconnections that may possibly exert anticompetitive effect by blocking the new entrants, does not apply with the auctions with financial schedules. Temporal and spatial dimension of the JETRA under nodal pricing is summarized in *Figure 5*

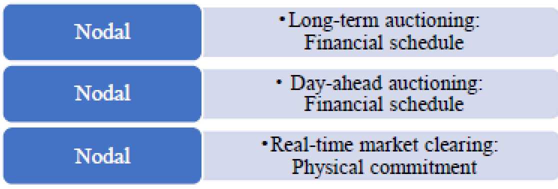

Figure 5 - Temporal and spatial dimension of the JETRA under nodal pricing

The zonal market is compatible with a decentralised market structure, in which the power exchange and transmission system operator at national level interact to clear the market. In theory, the nodes with similar electrical characteristics and geographical proximity can be aggregated into the same zone. The intra-zonal congestion cost should be minimal compared to inter-zonal congestion [22].

Both long-term and day-ahead market follow the inter-zonal network constraint in optimization. The awarded bids of financial transmission rights, physical transmission rights and forward energy contracts are financial in the long-term market. That is to say, in the day-ahead market coupling, all the previously awarded rights and energy contracts are liquidated and the right holders are paid the quantity awarded in long-term auction with the zonal prices determined at the day-ahead market.

Sequential allocation of the physical network capacity is implemented since day-ahead market. In day-ahead market, implicit auctioning guaranteed to some extent the optimal use of both energy and transmission capacity. In the redispatch and balancing, system cost optimization is performed by TSOs while taking into account transmission network constraint with nodal grid view. The sequential allocation in these time frames means that unlike the joint auction under nodal pricing, physical dispatch can not be liquidated by system operator win the multi- settlement rules. Administrative rules are needed to determine the compensation for change of physical commitment. The network capacity allocated to market participants in the implicit auction from day-ahead is also physical.

A major difference in these physical markets in the case study is that day-ahead market considers only inter-zonal constraints and the redispatch balancing market incorporates both inter-zonal and intra-zonal constraints in the case study. It is important to note that the energy and transmission rights settled at day-ahead market prices do not cover the cost after the day-ahead market gate closure. The redispatch cost is discussed in detail in Section 6. The temporal and spatial dimension of the JETRA under zonal pricing is summarized in *Figure 6*.

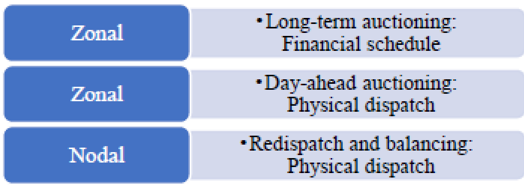

Figure 6 - Temporal and spatial dimension of the JETRA under zonal pricing

3.3 Case study network and bids

Using the network shown in Figure *7*, a case study is constructed. The network capacity limit of line 1-2 is 200 MW and the capacity limit of line 4-3 is 250 MW. The other lines have a capacity limit of 400 MW. Given this network topology and the maximal demand in this case study being 500 MWh, the maximal flow on any transmission element will not exceed 312.5 (500 *0.625) MW. Lines with 400 MW capacity can be seen as transmission elements without capacity constraints. In the joint transmission and energy auctioning, suppose there are 5 bidders. As the bids are hourly based, the energy and transmission rights are represented in unit MW in the tables showing results.

- Bidder 1 bids for financial transmission right from node 1 to node 3 at 10 €/MWhwith lower bound of 200 MWh and upper bound of 500MWh.
- Bidder 2 bids for energy sale from node 2 at 35 €/MWh with upper bound of 150 MWh.
- Bidder 3 bids for energy sale from node 4 at 20 €/MWh with upper bound of 300 MWh.
- Bidder 4 bids for physical transmission right for 100MW at 10 €/MW on the interconnection between node 1 and node 2 with upper bound of 150 MW.
  Bidder 5 bids for energy purchase from node 3 at 22 €/MWh with upper bound of 300 MWh

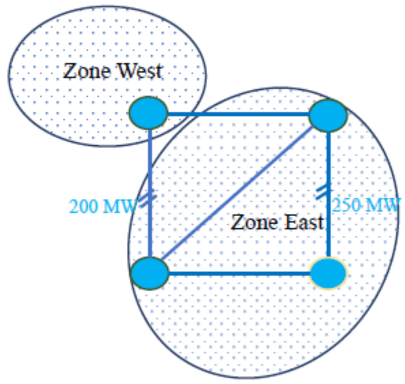

Figure 7 - Four nodes network with two capacity constrained lines

Assume that the marginal generator at node 2 has a cost of 80€ /MWh. The real time load at node 3 equals 500 MWh. Only the network users participate in the joint energy and transmission right auction in the market. There are no financial or virtual bids that are not backed up by physical generation or demand. In particular, the bidders who bid for financial transmission right and energy purchase contract are assumed to be agencies associated with demand at node 3.

In the zonal network representation, node 1 forms zone west, while node 2, node 3 and node 4 form zone east. Line 1-2 with limited transmission capacity is the interconnection line whose capacity limit is calculated as grid constraint. The bidders bid with the same cost structure. As opposed to bidding under nodal pricing, only zonal information is available for the bid location. For instance, the energy purchase bid only specifies withdrawal zone. The FTR only spec The case study in section 6 uses a simplified flow-based market coupling grid representation that does not calculate an internal network bottleneck. In reality, the impact of cross-border trade on the internal network is reflected in the critical branch identified by the TSOs. The selection of critical branches could vary substantially depending on the criteria. A common practice is to define critical branch by PTDF threshold, i.e the interzonal PTDF for a transmission line is larger than 5%. However, Van den Berghe et al point out that transparency of setting critical branch flow parameters is subject to questions [3]. The case study with a simple network configuration that does not take into account in the internal network constraint for market coupling thus represents the network operation where critical branches can not be effectively identified for all time frames. The critical branch in the case study refers to interconnection lines. As the experience in Texas also shows that when zonal market was implemented, zonal boundaries was adjusted every year to reflect the updated congestion pattern [23]. Therefore, the assumption made here is not unrealistic. Even with subdivision of current price zones, internal congestion can occur.

4. Joint energy and transmission rights analysis under nodal pricing

In this section, JETRA is organized under nodal pricing as an illustration of the auction mechanisms and acts as reference case for its implementation under zonal pricing. One question is worth careful examination for comparison with the mechanism under zonal pricing: how does the bid payments link markets in different time frames and provide hedging from user perspective?

Table 1 presents the β values of each bid using node 3 as hub. In the nodal market, the β values of each bid correspond to the nodal PTDF values of the bid, with node 3 defined as hub node in this network. The β values and link capacities are given in positive and negative direction. In the case study, node i is always the hub node, so its PTDF value on any transmission linkis
0. The duality of energy balance gives the hub nodal price. The locational marginal pricing of other nodes can be derived based on the hub energy price. The energy sale and purchase bids implicitly assume the withdrawal node is the hub node. For instance, the β values for bid 1 is shown in the fifth column in Table 1. Bid 1 represents financial transmission rights between node 1 and node 3. One unit of FTR means 1 MWh of injection at node 1 and withdrawal at node 3 that makes 0.5 MW of the power to flow through line 1-2 and then line 2-3. 0.5 MW of he power flows through line 1-4 and then line 4-3. The PTDF values on line1-2, line1-4 and line 2-3 are 0.5, while the negative directions of the same lines denoted as line 2-1, line 4-1 and line 3-2 have PTDF values of -0.5

	Capacity (MW)	Bid 1	Bid 2	Bid 3	Bid 4	Bid 5	Shadow price (€/MW)
Line 1-2	200	0.5	-0.125	0.125	1	0	15
Line 2-1	200	-0.5	0.125	-0.125	-1	0	0
Line 1-4	400	0.5	0.125	-0.125	0	0	0
Line 4-1	400	-0.5	-0.125	0.125	0	0	0
Line 2-3	400	0.5	0.625	0.375	0	0	0
Line 3-2	400	-0.5	-0.625	-0.375	0	0	0
Line 2-4	400	0	0.25	-0.25	0	0	0
Line 4-2	400	0	-0.25	0.25	0	0	0
Line 3-4	250	-0.5	-0.375	-0.625	0	0	0
Line 4-3	250	0.5	0.375	0.625	0	0	5

Table 1 - β values of each bid in nodal pricing on each network element

The long-term auction result is shown in Figure 8. Bidder 1 is awarded 375 MWh of financial transmission rights from node 1 to node 3. Bidder 2 and bidder 4 do not get their bids accepted. Bidder 3 is awarded 100 MWh of energy sale and bidder 5 is awarded 100 MWh energy purchase. The flow on the line 1-2 is 200 MW and on line 4-3 is 250 MW. The long-term auction payments are calculated in Appendix 2.

As day-ahead market has the same bids and same clearing outcome as long-term auction, the bid winners in the day-ahead market auctioning pay the SO exactly the same as in the long- term auctioning round and they get paid back this same amount from the SO as right holders. In real time market, the dispatch is shown in

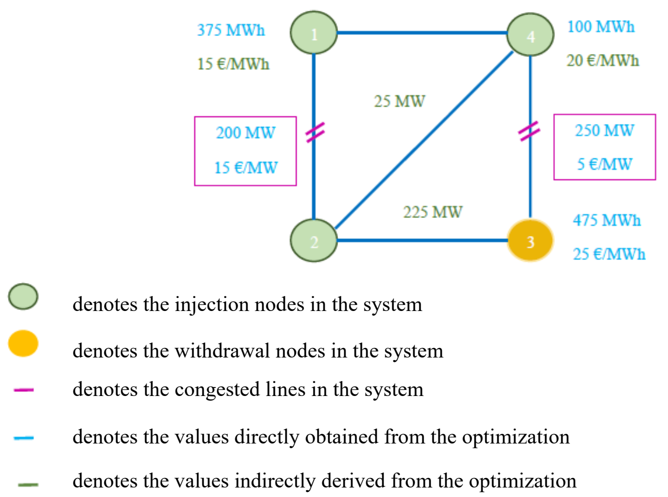

Figure 8 - Long-term auctioning results under nodal pricing

Figure 9. The payments in real-time market are calculated in Appendix 3. In real time market, the SO receives 67500 € from load at node 3, while it pays out 6000 € to generator at node 1, 1000€ to generator at node 4 and 4000 € to generator at node 2. There is a surplus of 56500 €. As *Table 5* in Appendix shows, the net payment from SO to the day-ahead bid winners equal 56500 €. There is revenue adequacy for SO. If the user at node 3 ultimately pays for the costs incurred by bidder 1 and bidder 5 who hedge congestion risk by obtaining FTR and an energy purchase contract, the total net payment from the user across different time frames is 15250€

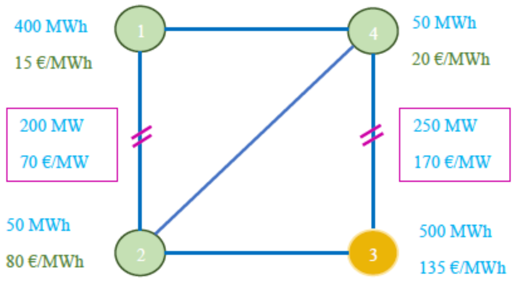

Figure 9 - Real time dispatch in scenario 2 under nodal pricing

5. Adapting flow-based market coupling to joint energy and transmission right auction

In this section, joint energy and transmission right auction is implemented in the long-term market under zonal pricing in conjunction with the day-ahead market coupling. Then the redispatch and balancing take place after day-ahead market gate closure.

5.1 Flow based market coupling under zonal pricing: Institution responsibilities and computation process of the JETRA in zonal market

Adapting flow-based market coupling method to a long-term auction first requires examination of current practices. Flow-based market coupling used in day-ahead market features cross border trade that maximizes social welfare while respecting constraints of the available interconnection capacity between bidding zones.

The objective function of zonal market clearing to maximize social welfare can be written as formula 5:

$$Max_{x\,b,z} \sum_{b,z} Q_{b,z} P_{b,z} \tag{5}$$

Where
$Q_{b,z}$ is the quantity of accepted supply or purchase bids b in the market zone z
$P_{b,z}$ is the price of bids b accepted in the market zone z

The zonal energy balance equation can be written as equation 6:

$$\sum_{b} Q_{b,z} + NEX_z = 0 \tag{6}$$

Where
NEX_z is the net export/import quantity for the market zone z.

The auction objective of flow-based market coupling is to maximize bid values while respecting the energy supply and demand equilibrium as well as interconnection flow limit. The shadow prices are calculated as the dual variables of the inter-zonal line flow constraint. The dual variable from energy balance equation gives the hub zone price, which is the demand zone in the case study. Similar to nodal pricing, under the flow-based market coupling, interconnection capacity allocation and interzonal transactions are simultaneously determined. Unlike nodal pricing, a simplified zonal network model is computed by the TSOs as a result of the forecast for market clearing. All the sellers within a bidding zone receive the same zonal price and all the buyers pay the same zonal price. The flow-based day-ahead market coupling segments the network flow estimation into two parts [24]. The first part is the flow associated with base case, which represents the best estimate for system state in the operating day. The second part is the flow as a result of zonal net position deviation between the day-ahead market and the base case. To close the gap between theday- ahead market operating point and base case, a set of generators with predetermined share of output change are assumed to react to the zonal net position changes. The GSK is thus defined the nodal change of the generation output in relation to the zonal net position variation. The zonal PTDF represents the distribution of power flow from a unit change of net injection or withdrawal of the specified zone on the interconnection lines. The remaining available margin refers to the available capacity on the critical network elements for the amount of net position change between forecasted base case (bc) and day-ahead market coupling outcome (da).

Detailed parameter explanation is given in Appendix 5. For joint energy and transmission auction, the base case is selected to represent the intra-zonal transactions with zero net position. The base case flow in the case study of this research is the reference flow, which represents the interconnection capacity usage when the generation and load are balanced within a bidding zone. The RAM is thus the available capacity for day-ahead cross-border trade after taking into account the impact of intra-zonal transaction on the network and operational safety margins, as equation 12 in Appendix 5 shows.

The flow constraints on the interconnection lines or critical network elements under zonal model can be expressed in equation 7 and equation 8. Unlike nodal pricing which can compute directly physical flows on lines if the grid typology does not change, the zonal net export is used in equation 8 to multiply with zonal PTDF to compute an estimated flows on interconnections

$$-RAM \leq F_l \leq RAM \quad (7)$$

$$F_l = \sum_z PTDF_{l,z} NEX_z \quad (8)$$

Where

F_l is the flow through interconnection line l.
RAM is the remaining available margin for line l.
$PTDF_{l,z}$ is the zonal power transfer distribution factor that represents impact of zone z on interconnection line l

Time step	Real-World Process for TSO and power exchange	Computation process
Prior to long- term auction	• Anticipation of market outcome several years in advance ofelectricity delivery • Construction of the grid model using the best estimate of system state	• Selection of the base case for long- term auction • Derivation of reference flow and GDSK from base case • Choose the flow reliability margin • Calculate the main gridparameters: zonal PTDF and RAM
In long-term auction day	• Supply andpurchase bids submission from market players to power exchanges	• Market simulation as centralised optimization
D-2	• Anticipation of market outcome two days prior to electricity delivery • Construction of the grid model using the best estimate of system state	• Selection of the base case for day- ahead auction • Derivation of reference flow and GDSK from base case • Choose the flow reliability margin • Calculate the main gridparameters: zonal PTDF and RAM
D-1	• Supply and purchase bids submission from market players to power exchanges	• Market simulation as centralised optimization
D	• Assess grid feasibility • Perform redispatch	• Nodal Optimal Power Flow(OPF) in the national or cross-border redispatch

Table 2 - Process and computation at different timestep for the JETRA

In both long-term auction and day-ahead flow-based market coupling, two parameters are the main outcome of grid model construction: 1) Zonal PTDF; 2) Remaining Available Margin (RAM). The calculation process and considerations of the two parameters in the day-ahead market coupling are described in Appendix. Their adaptation into JETRA in the long-term auction is included in section 5.2. Reflecting the impact of different level of cross-border cooperation, two redispatch models are implemented in the case study: 1) national based redispatch; 2) cross-border redispatch. Centered around the flow-based methodologies and the market process discussed in section 3, the role of TSOs and power exchanges for auctions at different time frames and computation process in JETRA under zonal pricing are summarized in *Table 2*.

5.2 Flow based market coupling methodological challenges and adaptation for JETRA

In this paper, we only consider the physical players such as generators or loads entering the auctions to procure energy bids or transmission rights. In the JETRA under nodal pricing, firmness of financial transmission rights and flow feasibility within each round of the auction is guaranteed by the flow constraint. FTR as the forward sale of the network capacity, are allocated in an optimization process together with energy and PTR under the nodal view of network. However, in practice, the stochastic nature of network capacity in the long-term can impact the FTR allocation. As the details in network capacity evolve with time, the ISO in the
U.S uses a simplified network model for FTR auction and a reparameterized model in day- ahead market with new constraints imposed and others relaxed. This discrepancy between models can cause the capacity sold in FTR auction to differ from day-ahead market [25]. In this section, we focus on the methodological comparison of JETEA under nodal and zonal pricing so that the stochastic nature of transmission capacity is not taken into account. The same grid model with the same network elements for long-term and day-ahead market is used under nodal pricing. The compatibility between JETRA in the long-term auction and flow- based market coupling is analysed for key parameters: base case, the PTDF formulation and generation demand shift key rules. Afterwards, the adoption of JETRA in the day-ahead market is discussed.

5.2.1 Grid modelling for JETRA in long-term market

a) Base case effectiveness in long-term auction

The base case application is under the assumption that when the base case and real time operation point are close, the small net position gap can be served by anticipating a set of generators with predetermined output change ratio [26]. As noted by Voswinkel et al, the expected net position uncertainties in the base case construction are linked to forecast errors of intermittent energy sources, load variations and unexpected plant outage. These factors contribute to RAM forecast error in day-ahead market [27]. These forecast errors are amplified in the long-term timeframe. Using a reference day with current generation load profile as base case for long-term auction is subject to too high uncertainty and this approach is not applied.
The base case approach in long-term auction may face structural change as a result of generation investments, retirements or load shifting. In the joint auction mechanism, the energy purchase quantity only reflects the total amount of energy bid into hedging products
from demand side and it might not equal to the real time load. Furthermore, given the nature of OTC bilateral contracts, the injection and withdrawal nodes of bilateral contracts are unknown to TSOs under current regulation. Under zonal pricing, only injection/withdrawal zonal information is envisioned to be available regarding the FTR bids in the joint auction.
Similar to the base case approach used for day-ahead market coupling, we can observe the bidding information available from last round of long-term joint auction that occurs weeks or months before the current auction round. Suppose in last auction, there is much less accumulated energy purchase at node 3 compared to its current demand level as the main load centre. Several factors may explain the phenomenon. It is possible that the demand at load 3 plans to sign a cross-border long-term bilateral contract for a large share of its future demand or the demand at load 3 deploys a bidding strategy to acquire part of its load at later market frames in anticipation of lower price in spot market. Given the lead time before electricity delivery, questions can also be asked whether it's due to planned structural change at demand side. For instance, the reasons contributing to lower energy bids in long term auction can be planned demand shift at node 3 through moving the industry elsewhere or a net demand reduction as a result of investments in local generations. This example shows that using

reference day generation and load bid profiles from historical data may not be applicable for long-term auction.
In addition, the base case approach is not compatible with the flow constraint equation in JETRA design. Following the base case reference flow estimation, there are effectively two sets of PTDF values used for interconnection flow computation. Base case assumes generation/load pattern that can be seen as having a set of GSK and zonal PTDF from the operating point with zero interzonal transaction to the base case net position level. The GSK method assumes a range of preselected generators to fill the gap between base case and the real operating point. This in essence constructs another set of interzonal PTDF. The base case method implemented in current FBMC is not compatible with design, in which only a single PTDF value is used for each bid to account for flow constraint under nodal pricing.
Given the uncertainties in long-term transactions and the need to ensure interconnection feasibility, currently implemented base case from D-2 estimation with patterns of load and generations assumed may not be an easy starting point to derive the GSK and zonal PTDF. Base case used in this research attempts to approximate intra-zonal transaction impact on interconnection flow at zero net import/export level. The base case derived for long-term and day-ahead auction is shown in Appendix 6 and 7. The reference day generation load pattern after redispatch is used to take into account the total flow on interconnection. The load flow as a result of interzonal power exchange is deducted from the total to account for the intrazonal transaction impact on interconnection. The deviation of base case intrazonal transaction pattern from the real operating point is dealt with by applying the flow reliability margin in different time frames in RAM computation.

b) One set of interzonal PTDF under zonal pricing

In the original JETRA design, separate PTDF values are used for energy purchase/sale and financial transmission rights in the network flow constraint calculation. Following the flow based market coupling process, the grid model with interzonal PTDF value is made prior to market opening. There is no bidding information about energy purchase/ sale bid volume and exact locations for this type of bid. Furthermore, there is no information about FTR volume and injection/withdrawal node. Therefore, it is extremely difficult for TSOs to predict the details for these two bid types and determine β_2 and β_g separately, if ever possible. In this research, an integrated interzonal PTDF is used to represent the combined effect of cross border transactions by energy purchase/sale bids and by FTR on interconnection flow.

While the current GSK methodology represents forecast output change among a preselected generation set as a result of zonal net positions, the combination of bilateral contract and FTR is a transaction pattern that gives grid users selection choices, i.e the amount of cross-border trade and the injection withdrawal nodes. With one integrated PTDF for interzonal transactions, we assume that at aggregated level, energy and FTR follow the same injection andwithdrawal pattern.

c) GSK challenge

To ensure cross-border FTR firmness under zonal pricing, interconnection flow feasibility needs to be guaranteed. When the interconnection flow resulting from the FTR is infeasible, redispatch or curtailment is needed to relieve the interconnection congestion. As FTR is the forward sale of transmission capacity, the market players that pay for financial transmission rights to back their bilateral contracts should not be allocated additional costs for the cross- border transmission service. Otherwise, FTR in the joint auction does not function effectively as hedging instrument against congestion risk.
The information asymmetry between system operator and market players poses a major challenge for long-term auction grid modelling. Facing the inherent difficulty to calculate the interconnection flow by giving accurate PTDF values separately for energy purchase/salebids and FTR, a conservative grid modelling should be made to ensure the interconnection flow feasibility. In the long-term auction, we propose two rules for Generation Demand Shift Key (GDSK) in the import region: 1) dispatchable generators; 2) generation decrease or demand increase at the node associated with critical transaction from congestion perspective for interconnection lines. The first rule follows flow-based market coupling approach that ensures reliable system operation. The second rule is made to ensure the interconnection flow feasibility for FTR.

In the case study, there is only one market player from zone west bidding for cross-border FTR so that all the cross-border trade is FTR in long-term auction. In general, by having one set of PTDF, it is implicitly assumed that the cross-border energy purchase/sale bids and the FTR follow the same GDSK metric from the zero cross-border trade equilibrium point. The rational of giving heavier GDSK weight for the withdrawal node that is associated with most critical cross-border transaction pattern can be explained by a simple example. For instance, if the corresponding TSO assumes the FTR withdrawal point in zone east is at node 3. The zonal PTDF will then be 0.5 and maximal allowed transaction will be 400 MW from zone west to zone east. If the real FTR withdrawal point turns out to be node 2, the zonal PTDF will turn out to be 0.625 and maximal allowed transaction will be 320MW. The allocated FTR in the auction clearing between 320MW and 400MW from zone west to zone east can not be firm.

5.2.2 Grid modelling for JETRA in day-ahead market

In JETRA design, the precondition for revenue adequacy is to have the β values used in later auction round being smaller or equal to those of previous auction. The network capacity available for later auction round should also be made larger or equal to that of previous auction. Given the information asymmetry for grid modelling process, making good estimation of volume and locations for energy bids and bilateral contracts remains difficult in day-ahead market. Moreover, day-ahead auction needs to follow the long-term auction practice to have consistent market clearing algorithm. Therefore, one integrated PTDF is used for cross border trade in day-ahead timeframe.

$$PTDF_L \geq PTDF_D \tag{9}$$

$$RAM_L \leq RAM_D \tag{10}$$

Where

$PTDF_L$, $PTDF_D$ are the PTDF values in long-term auction and day-ahead auction respectively.
RAM_L , RAM_D are the remaining available margin in long-term and day-ahead auction respectively

Day-ahead market in Europe under zonal pricing is treated as the real-time market under the nodal pricing, since they both involve physical dispatch. Under nodal pricing, the bilateral trade is made binding by setting the lower and upper boundary to the FTR bid backing the bilateral contract at real-time market [9]. Under current market rules, the exact positions of bidders are revealed to the system operator after market closure. Moreover, there is no nodal representation in zonal network to apply in FTR bid that can be specified with injection/withdrawal location. Similar to the approach in long-term timeframe, we make the cross-border transmission right bilateral contract firm by constructing a more conservative grid model in day-ahead market. At the same time, GDSK rules used in day-ahead market are relaxed to make sure inter-zonal PTDF in day-ahead timeframe is smaller than that of long- term auction.

5.2.3 Two redispatch models

After the day-ahead market closure, the case studies directly come to redispatch phase. Different levels of cross-border redispatch coordination have a significant impact on the system cost as the studies from Oggio et al and Kunz et al show respectively [28][29].

Two redispatch models are implemented in the case study. The first model follows a national redispatch approach that only allows TSOs to use the resources within their bidding zone to alleviate internal network congestion. In this case, the interconnection capacity utilization is kept unchanged from the day-ahead market clearing. Only the intra-zonal network capacity limit is imposed as the constraint for altering generation load patterns. The second model implements a deeply integrated cross-border redispatch mechanism. Under this approach, the TSOs coordinate as if there is a single system operator across the borders that can optimize the generation resources and network capacity to minimize the system cost. The real flow on the interconnection as a result of day-ahead schedule is calculated and the remaining interconnection capacity can be utilized in the redispatch process. At the same time, the intra- zonal constraint is included in the optimization to alleviate congestion on the overloaded lines.

A simplified assumption is made here regarding redispatch cost: 1) the TSO pays generation that increases production according to its original bidding price in day-ahead market; 2) the generation that is required to decrease production pays back the avoided generation costs to the system operator, which is approximated by the generation bid price in day-ahead market.

6. Case study under zonal pricing

6.1 Long-term joint energy and transmission right auctioning

6.1.1 Ex-ante computation of zonal PTDF and RAM for long-term auction

Assume the same five bidders participate in the auction and offer the same price and lower upper limits as in the nodal case. The bids under zonal pricing only contain zone specific information such as injection and withdrawal zones for FTR. Using the model of O'Neill et al, the joint auctioning can be organized between two zones. TSOs in each bidding zone act as system operators. To ensure system reliability, a conservative view of the internal transaction is needed to take into account the higher uncertainty level in the long-term auction.

As explained in previous section, GSK can be set by a weighted combination of the three factors. In our case study, node 4 is an intermittent generator in zone east with generation cost slightly higher than that of generator at node 1. Generator at node 2 represents dispatchable generation and has the highest cost. Transaction between node 1 and node 2 has the highest PTDF value on interconnection line 1-2.

Among the generators at node 2 and node 4, generator at node 2 should be selected and given higher weight according to the GDSK criteria. One unit of import from zone west can be offset by either increase in demand or decrease in generation output in zone east. In the network modelling for long-term auction, TSO gives a more conservative assumption to assume a unit export from zone west leads to 0.5 MW generation decrease at node 2 and 0.5 MW demand increase at node 3. GDSK between node 2, node 3 and node 4 is set to be (0.5, 0.5, 0). Inter- zonal PTDF on interconnection 1-2 takes the value of 0.5625 in long-term auction.

The Central Western European (CWE) TSO technical report states that usually 5-20% of maximal capacity is reserved as the FRM for the day-ahead market coupling [30]. In the long- term auction, uncertainties regarding the capacity calculation process are higher given the long lead time for generation load forecast. In this research, the upper value of FRM range in the day-ahead market coupling is taken as FRM for interconnection 1-2. With a reference flow of 37.5 MW and FRM of 40 MW, the RAM on interconnection 1-2 is 122.5 MW. The maximal export from zone west to zone east can thus be calculated: 217.8 MW (122.5/0.5625). Long- term joint auctioning result is shown in Figure 10. Bidder 1 is awarded 217.8 MWh of financial transmission rights from zone west to zone east. Bidder 2 and bidder 4 do not get their bids accepted. Bidder 3 is awarded 300 MWh of energy sale and bidder 5 is awarded 300 MWh energy purchase. The payments in long-term auction are calculated in Appendix 8.

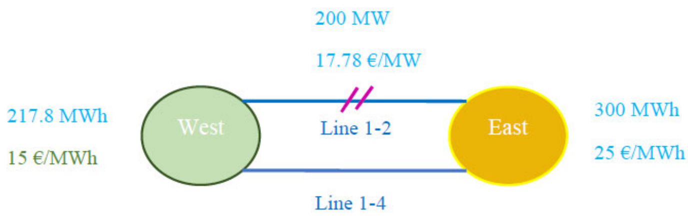

Figure 10 - Long-term joint auctioning results under zonal pricing

6.1.3 Ex-post GDSK/PTDF calculation in long-term auction

The long-term market clearing result hinges on the GDSK and zonal PTDF values. In this subsection, we ask the question what the theoretical optimal GDSK could be. With the hindsight from auction clearing under nodal pricing, the nodal dispatch outcome is compared with base case generation load pattern to derive the theoretical optimal GDSK. Using nodal net changes in the import zone from base case to nodal dispatch outcome, the optimal GDSK is calculated. The key differences between grid representation using nodal and zonal information in long-term auction can be summarized below:

- Ex-ante calculated GDSK between node 2, node 3 and node 4 is (0.5, 0.5, 0) following the FB market coupling approach, while theoretical optimal GDSK value according to the nodal dispatch is (0, 0.47, 0.53).
- The inter-zonal PTDF in long-term auction using ex-post computed theoretical optimal GDSK is 0.434. The ex-ante interzonal PTDF under zonal pricing is 0.5625.
- The capacity of line 1-2 used in long-term auction under nodal pricing is 200 MW. The remaining available capacity in long-term auction under zonal pricing is 122.5 MW, although this value has deducted the interconnection flow incurred by intra-zonal trade. Separating intra and inter zonal trading for network capacity calculation brought uncertainties in the interconnection remaining available margin.
- The maximal interzonal transaction enabled is 375 MW under nodal pricing. With the RAM set at 122.5 MW following the FBMC approach, the maximal interzonal transaction enabled by the ex-ante computed zonal PTDF is 217.8 MW (122.5/0.5625), while the maximal interzonal transaction allowed by theoretical optimal zonal PTDF is 282.3 (122.5/0.434) MW.

The generation shift key deviation at node 2 between the two GDSK metrics can be explained as the result of conservative grid modelling in long-term timeframe under zonal pricing. Another difference worth noticing between the two GDSK metrics is demand change estimation. The objective of the joint auction is to maximize bid value and the demand purchase bid is not binding prior to real time. The total withdrawal of 475 MW at node 3 in long-term auction under nodal pricing is a result of optimization instead of real-time load data. The total withdrawal at node 3 in long-term auction under zonal pricing becomes 517.8MW. In this setting, to estimate the nodal demand change in GDSK metric can be technically much more challenging with ex-ante determined rules, if ever possible.

6.2 Day ahead market coupling

6.2.1 Ex-ante computation of zonal PTDF and RAM for day-ahead market coupling

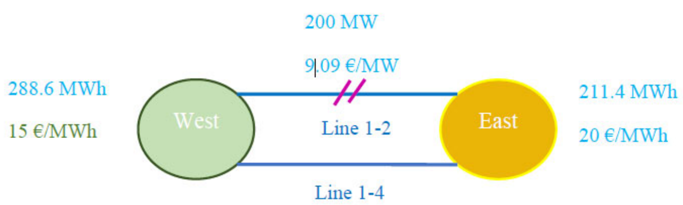

Figure 11 - Day-ahead market clearing result under zonal pricing

In the day-ahead market, the reference flow 31.25 MW as shown in Appendix 7. It is deducted on the total capacity of interconnection 1-2 to take into account the effect of intra-zonal trading. For day-ahead market coupling, FRM is assumed the lower value of its historical data range for this time frame, i.e 5% of the interconnection maximal capacity. The RAM is 158.75 MW for day-ahead auction. The day-ahead clearing result is shown in Figure 11. The payments in day-ahead market are calculated in Appendix 9.

6.2.2 Ex-post GDSK/PTDF calculation in day-ahead market coupling

Similarly, zonal PTDF leading to optimal dispatch with nodal information can be computed ex-post by comparing the day-ahead auction dispatch under nodal pricing with the base case generation and load pattern. The theoretical optimal GDSK can be calculated using nodal net changes in the import zone. The day-ahead market under zonal pricing is physical and the demand does not change from day-ahead to real-time market in the case study. We use real- time nodal market dispatch for the optimal GDSK computation, as this is the only physical market under nodal pricing. The key differences between grid representation using nodal and zonal information in day-ahead auction can be summarized as below:

- Ex-ante calculated GDSK between node 2, node 3 and node 4 is (0.4, 0.6, 0), while theoretical optimal GDSK value according to the nodal dispatch is (0, 0.375, 0.625). The Euclidian distance between the two metrics is 0.775.
- The inter-zonal PTDF for day-ahead auction using ex-post calculated theoretical optimal GDSK is 0.42, while the ex-ante determined interzonal PTDF is 0.55.
- The capacity of line 1-2 used in day-ahead auction under nodal pricing is 200 MW. The remaining available margin in day-ahead market coupling under zonal pricing is 158.75 MW. The latter already considers the impact on interconnection flow caused by intrazonal trade.
- The maximal interzonal transaction enabled is 400 MW under nodal pricing. It is important to note we use the real time dispatch outcome under nodal pricing to compute theoretical optimal GDSK, so that the maximal interzonal transaction reference is also taken from real-time clearing outcome under nodal pricing. With the RAM set at 158.75 MW following the FBMC approach, the maximal interzonal transaction enabled by the ex-ante computed zonal PTDF is 288.6 MW(158.75/0.55), while the maximal interzonal transaction allowed by theoretical optimal zonal PTDF is 378 (158.75/0.42) MW

It is important to note that the day-ahead market is the last round of auction open to market participants under zonal pricing. The estimation GDSK for this timeframe thus determines how close the auction outcomes can approximate the optimal outcome under nodal pricing. In contrast to the long-term auction, when theoretical optimal GDSK is used, the maximal allowed interzonal transaction volume is much closer to the value under nodal pricing. This can be mainly explained by the fact that RAM uncertainties adopted in the case study for day-ahead market is not as great as the long-term auction.

6.3 Redispatch

6.3.1 Costs under national and cross-border redispatch

Neither the long-term energy and transmission right auctioning nor the day-ahead market coupling has considered the internal network bottleneck under zonal pricing. After gate closure, the system operator will assess the feasibility of day-ahead market clearing outcomes by calculating load flows on the whole system. When the estimated power flow exceeds network capacity limit, the system operator can alter scheduled generation or load pattern from day- ahead market, in order to relieve congestion. Some generators located in certain location that have not been scheduled in the market coupling since their costs are higher than the market clearing price are required to dispatch up and some generators that have been scheduled to produce in day-ahead market are required to reduce their production.

After the day-ahead market clearing, estimated flow on line 4-3 is 276.4 MW and redispatch by the TSO is needed. Under national based redispatch where TSOs are only allowed to dispatch resources within their bidding zone, the same redispatch volume is needed at node 4 and node 2. Generator at node 4 will be required to reduce its generation from 211.4 MWh to 105.8 MWh and pays the TSO 2112 € for avoided generation cost. Generator at node 2 will be asked to produce 105.6 MWh and is paid 8448 €. The additional cost for the TSO is 6336€.

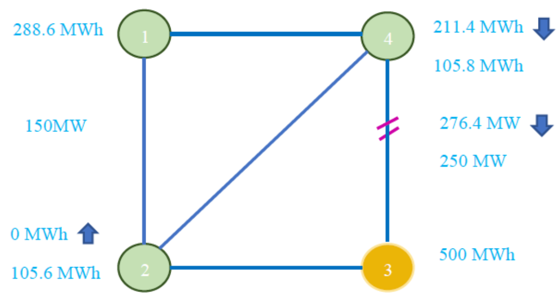

Figure 12 - National based redispatch result

When cross-border redispatch is conducted, the TSO will require the generator at node 1 to increase generation by 111.4 MWh, the generator at node 2 to start and dispatch up with 50 MWh and the generator at node 4 to dispatch down with 161.4 MWh. The result is shown in Figure 13. To account for the added generation cost by dispatching up plant at node 1 and node 4 as well as avoided costs by dispatching down generation at node 3, redispatch cost 2443 € is incurred.

Cross-border redispatch can lower the total system cost significantly under zonal model. The total payment of the user may get closed to nodal system in this arrangement. However, several issues arise. Implementing integrated cross-border redispatch requires centralised operation that coordinates market and system operation across borders. In addition, the need of cost allocation by negotiated rules arises. As far as the pricing rule for redispatch is concerned, this research assumes that the power plants that are dispatched down need to pay back the system operator their avoided generation costs. The welfare losing market players in the process of redispatch may prefer to have the day-ahead market functioning properly and send efficient price signal at first place, otherwise a compensation scheme might be expected.

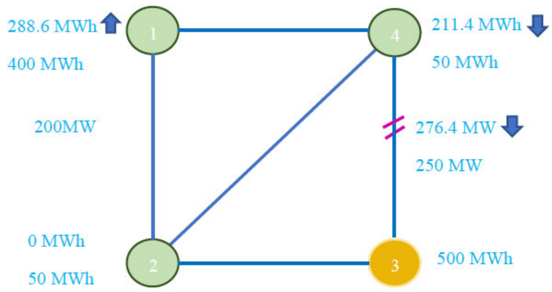

Figure 13 - Cross-border redispatch result

6.3.2 Ex-post GDSK calculation in redispatch

In this subsection, ex-post GDSK is derived by comparing the national based redispatch outcome in *Figure 12* with base case used in day-ahead market. The GDSK metric between node 2, node 3 and node 4 is (-0.19, 0.52, 0.67). Under the national based redispatch, generator at node 2 increases with the increase of import in zone east. Therefore, there is negative sign at node 2. The theoretical optimal GDSK (0, 0.375, 0.625) for day-ahead market using nodal dispatch outcome is calculated in section 6.2.2. The Euclidian distance between the ex-post GDSK based on national redispatch and the theoretical optimal GDSK for day-ahead auction is 0.243. The national based redispatch reduces the Euclidian distance of the GDSK metric with the theoretical optimal one from 0.775 in day-ahead market. Under national based redispatch, network capacity in interconnection line 1-2 is not fully used.

GDSK derived from the cross-border redispatch and base case used in day-ahead market is (0, 0.375, 0.625). The cross-border redispatch result is the same as the real time market outcome under nodal pricing. Therefore, the realised GDSK after cross-border redispatch equals the theoretical optimal GDSK. The Euclidian distance between the ex-post GDSK metric from cross-border redispatch and the theoretical optimal GDSK is 0.

After the spot market closure, redispatch could be seen as a process used by TSOs to correct the ex-ante determined GDSK metric with nodal grid view in order to relieve congestion. It effectively forms another set of realised GDSK that deviates from values used in day-ahead auction. The ex-post adaptation of GDSK by TSOs implies not only change of the dispatch outcome from wholesale market but also additional redispatch costs. This raises the question whether the auction energy contracts and transmission rights that link long-term and day-ahead markets can be used as effective hedging instruments under zonal pricing.

6.4 Observations for zonal market outcomes

Revenue adequacy: revenue adequacy can be held in day-ahead and real-time market for SO under nodal pricing. While it can be kept for SO in the day-ahead market under zonal pricing, after

redispatch, SO can not maintain revenue adequacy.
GDSK: ex-ante computed GDSK for grid modelling under zonal pricing deviates from the theoretical optimal values calculated from nodal pricing dispatch in long-term and day-ahead market.
Cost for market player: total cost for the grid user at the demand node 3 who represent bid 1 and bid 5 under nodal and zonal pricing is summarized in Table 3. In total, the user pays 18925 € across all time frames under national redispatch. Under integrated cross-border redispatch, the user pays 15032 € across all time frames.

	Nodal pricing	**Under national redispatch**	**Under cross-border redispatch**
Total costs (€)	15250	18925	15032

Some immediate observations can be made from zonal case study in comparison with nodal pricing.

- Under zonal pricing, the FTR cleared in the long-term joint auction 217.8 MWh is significantly reduced as opposed to 375 MWh under nodal pricing. The limited FTR auction volume is a result of the conservative zonal grid model regarding the inter-zonal flow limit and maximal export in the long-term time frame with higher uncertainties.

- The uncertainties analysed in this research involve: 1) forecast of future generation and load location and volume to compute base case and reference flow; 2) the predetermination of generation demand shift key in order to calculate zonal PTDF. In the long-term market, higher uncertainties for grid operator to approximate the impact of intra-zonal trade on the interconnection capacities implies higher flow reliability margin and thus lower RAM. A predetermined generation demand shift keys implies that generation dispatch order does not go through optimization with nodal grid constraints simultaneously. Given the higher uncertainties, GDSK in the long-term auction needs to be made more conservative than day-ahead. This severely limits the maximally allowed inter-zonal trade volume.

7 Conclusion

In light of accelerating decarbonization, there is growing interest in long-term cross-border electricity markets that send stable price signals to consumers. The joint energy and transmission right model developed by O'Neill et al. is proposed to link the long-term and spot markets in Europe. In JETRA, financial hedge products can be sought in the form of financial transmission rights, physical transmission rights, and energy sale/purchase contracts.

The success of developing a long-term market through the joint auction of energy and transmission rights depends on the underlying market structure. This research set up a stylized network case to showcase the implementation of JETRA under nodal pricing and compare its performance under zonal pricing. The compatibility of the current European zonal market design and governance with JETRA is investigated in terms of consistency between markets in different time frames and consistency between intra and inter bidding zone markets. The grid modelling of flow-base market coupling assumes that the gap between the base case and the real-time operating point is filled by a set of generators changing their output with a predetermined share. This assumption is challenged by the JETRA implementation because it involves multiple hedging instruments and potentially inter-temporal hedging strategies by market players.

Under nodal pricing, independent system operator takes on the role of operating network and market simultaneously in the implementation of JETRA. The auction results are financial prior to the real-time market and a consistent nodal grid model is used across different timeframes. In the current European electricity market, governance of day-ahead market coupling revolving around zonal pricing determines the institution setups and their functions, which exert a fundamental impact on long-term market development. TSOs and power exchanges interact to clear the day-ahead market. In the implementation of JETRA, market clearing under zonal pricing can only be made financial in the time frames prior to the day-ahead, since dispatch from the day-ahead on is physical. The final payback to transmission right holders or energy contracts in forward markets are settled at the day-ahead price.

From the system operator perspective, there is less interconnection capacity utilized for cross- border trade under zonal pricing, compared to nodal pricing. The inherent methodological dilemma to adapt to flow-based market coupling is linked to the fact that grid modelling is made prior to market opening. The original design of JETRA requires assigning grid parameters for each bid. This means that under zonal pricing, the system operator needs to forecast the volume, injection and withdrawal nodes for each bid. The information asymmetry between market players and the system operator poses significant challenges for implementing JETRA, particularly in the long-term market with higher uncertainties. To adapt to flow-based market coupling, we simplify the grid parameters. However, the requirements for FTRs to be binding implies that a conservative grid model is needed for zonal pricing. The deviation between ex-ante calculated flow-based grid parameters in zonal pricing and theoretical optimal values contributes to the increase in system costs. Another dimension to foster effective cross- border cooperation is revenue adequacy for the system operator. Under zonal pricing,

consistency for price formulation in the long-term and day-ahead markets can be maintained since both implement a zonal network for market clearing. However, redispatch with a nodal grid model breaks consistency with the wholesale market and incurs additional costs. In the case study, revenue adequacy for the system operator is breached with both national based and integrated cross-border redispatch. This implies that instead of cost allocation based on price signal across borders, administrative negotiated rules may come into play.

From the grid user perspective, the hedging function of long-term cross-border transmission rights and energy contract is much weaker in the joint auction under zonal pricing compared to nodal pricing. An important reason is that there is less cross-border trade potential under zonal pricing. It can be observed in the case study that much fewer cross-border FTRs are allocated to market players in the long-term auction under zonal pricing compared to nodal pricing. Another explanation is that there is a different level of granularity for network constraints used in the optimization process. Nodal pricing provides a consistent nodal grid model for the market in different time frames. Under zonal model, the nodal view of the grid is only implemented in the redispatch where buyer bids are not open to market participants anymore. Thus, the transmission rights and energy contracts issued from the joint auctioning based on the zonal model in the long-term auctions can not hedge against redispatch costs incurred after the market closure that uses a nodal grid model with all intra-zonal constraints.

We conclude that reforming zonal pricing into nodal pricing is a prerequisite towards developing an efficient long-term market with the joint energy and transmission right auction. To achieve this, TSOs and power exchanges need to be merged to provide simultaneous optimization of network and market conditions in different time frames.

This research does not include strategic bidding behaviours or cover detailed auction design options when comparing the nodal and zonal markets. A simplified zonal market that mainly investigates uncertainties from GDSK is constructed. There are other factors that can influence zonal model uncertainties. Future research should be expanded in these areas.

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Appendix

Financial transmission rights and physical transmission rights

In *Figure 14*, three node network is used to illustrate the use of FTR. Assume the three transmission links have the same electrical characteristics, i.e the same impedance. A market player has a bilateral contract for 150MWh energy transaction between node A and node C. To hedge the congestion risk, the player can procure 150 MW of financial transmission right between node A and node C in auction and get paid back the multiplication of 150 and price differences between node A and node C.

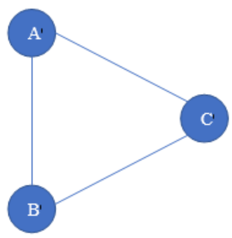

Figure 14 - Three node example for FTR procurement

In the same example as the previous paragraph, the nodal PTDF for the transaction between node A and node C is 0.33 on link AB, 0.33 on link BC and 0.67 on link AC. Hedging of 150 MW energy transaction from node A to node C by physical transmission right implies the market player needs to procure 100 MW PTR on the link AC, 50 MW on link AB and 50 MW on link BC

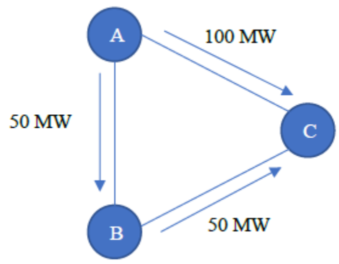

Figure 15 - Three node example for PTR

$$LMP_m - LMP_l = \sum_{all\ flowgates\ h} SP_h * (PTDF_{h,m} - PTDF_{h,l}) \quad (11)$$

Where:
m denotes the withdrawal node.
l denotes the injection node.
h denotes the transmission element h on the transmission path that connects node m and node l.
LMP refers to locational marginal price of certain node.
SP refers to shadow price of certain transmission elemen

2. Long-term auction outcome under nodal pricing

The flow on line 1-4 is 175 (375*0.5 + 100*(-0.125)) MW, line 4-2 being 25 (100*0.25) MW and line

2-3 being 225 (375*0.5 + 100*0.375) MW. Shadow price of link 1-2 and link 4-3 is 15€/MW and 5€/MW respectively. From shadow prices obtained in optimization we can also see that line 1-2 and line 4-3 reach the capacity limit. The locational marginal price in hub node 3 is the dual of energy balance equation that equals 25 €/MWh.

Using LMP and shadow price calculation formula, the FTR price for bid 1 that accounts for nodal price difference between node 1 and node 3 is 10 (15*0.5 + 5*0.5) €/MWh. Nodal price difference between node 4 and node 3 is 5 (15*0.125 + 5*0.625) €/MWh. The LMP at node 4 for bid 3 is 20 (25-(15*0.125 + 5*0.625)) €/MWh. Similarly, nodal price difference between node 4 and node 1 can be calculated to be 10 (15*0.5 + 5*0.5) €/MWh. LMP at node 1 is 15 (25-(15*0.5+5*0.5)) €/MWh. The payments from long-term auction bid winners to the SO are listed in the last row from Table 4. Bidder 1 pays 3750 € to the SO for the 375 FTR between node 1 and node 3 and bidder 5 pays 2500 € to SO for 100 MWh of energy purchase rights. At the same time, SO pays 2000 € to bidder 3 for 100 MWh of energy sale rights.

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price (€/MWh)	10	35	20	10	25
Result quantity (MWh)	375	0	100	0	100
Result price (€/MW)	10	0	20	0	25
Payment to SO (€)	3750	0	-2000	0	2500

Table 4 - Payment from the bid winners to the SO in the long-term auction

3. Day-ahead and real-time market under nodal pricing

The bid winners in the day-ahead market auctioning pay the SO exactly the same as in the long- term auctioning round and they get paid back this same amount from the SO as right holders. In real time market, the dispatch is shown in
Figure 9. Generator at node 1 will produce 400 MW and generators at node 2 and node 4 will each produce 50 MW. Under this dispatch, both line 1-2 and line 4-3 are congested with a shadow price of 70 €/MW and 170 €/MW respectively. The LMP at the hub node is 135 €/MW. LMP at node 1, node 2 and node 4 is 15 €/MW, 80 €/MW and 20 €/MW respectively. Line 1- 2 and line 4-3 in the long-term, day-ahead and real-time market is fully utilized.

In real time market, the SO receives 67500 € from load at node 3, while it pays out 6000 € to generator at node 1, 1000€ to generator at node 4 and 4000 € to generator at node 2. There is a surplus of 56500 €. The surplus is used to pay bid winners in the day-ahead market auctioning. FTR for bidder 1 is worth 120 €/MW. As Table 5 shows, bidder 1 receives 45000€ from the SO for the 375 MW of FTR it holds. Bidder 5 that holds energy purchase right at node 3 is paid at the nodal price of 135€/MW and receives 13500€ from SO for the 100 MWh right. Bidder 3 who is paid by SO for the energy sale contract in the previous auction round needs to pay to the SO according to the real-time LMP at node 4. In total, bidder 3 pays SO 2000€. The total net payment from the SO to the bid winners is 56500€. The surplus from load and generation payment equals SO net payment to bid winners. Revenue adequacy is reached for the SO in the day-ahead market, i.e., no short fall of revenues for the SO to settle the energy and transmission right bids

	Bidder 1	Bidder 2	Bidder 3	Bidder 4	Bidder 5
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	375	0	100	0	100
Price (€/MW)	120	0	20	0	135
Payment to SO (€)	45000	0	-2000	0	13500

Table 5 - Payment from SO to the previous round bid winners in day-ahead market under nodal pricing

4. Accumulated user costs and intertemporal cost components

If the user at node 3 ultimately pays for the costs incurred by bidder 1 and bidder 5 who hedge congestion risk by obtaining FTR and an energy purchase contract, how effective do the hedging instruments function?

In the following calculation, the price paid or received by bidder 1 and bidder 5 is categorized as the user expenditure. The user will pay 3750€ to obtain 375 MWh FTR between node 1 and node 3 and 2500 € for the 100 MWh energy purchase contract in the long-term auctioning. In the long-term and day-ahead auctioning, the user has paid 6250 € for hedging instruments that covers 475 MWh of the total load. In the day-ahead, the user pays and receives the same amount. At real-time, the user at node 3 pays 67500€ for the 500 MWh total load. However, the SO pays back the user 45000€ for the FTR and 13500€ for the energy purchase contract. In total, 58500€ is paid back to the user at real time and this accounts for a significant share of the 67500 € of the load payment at real-time price. The total net payment from the user across different time frames is 15250€. This calculation shows that in times of large price variations in the spot market, holding energy and congestion hedging instruments such as FTR in long- term and day-ahead timeframe can reduce the risk exposure significantly from user perspective.

The total payment made by the user employing congestion hedging instruments in the long- term and day-ahead auctioning can be decomposed into costs in different time frames. At day- ahead market, the user gets paid back at day-ahead price for procuring the FTR in long-term auction. Eventually, what the user pays for FTR can be further linked to its long-term right clearing price. The user only needs to pay the real-time market price for the incremental power that's not covered by its hedging portfolio from long-term and day-ahead market. A consistent breakdown of costs shows the rewards of hedging instrument deployment for market players.

5. Flow based market coupling parameters

a) RAM computation

As shown in equation 9, remaining available margin used in day-ahead market coupling differs from the maximal line capacity. There are several components subtracted from maximal allowed physical flow: a reference flow F_{ref}, a flow reliability margin (FRM) and final adjustment value (FAV). These parameters should be predetermined by the TSOs prior to long- term or day-ahead auction in our case study. While PTDF factors deal with relation between critical network flow and inter-zonal transactions, intra-zonal transaction impact on the network capacity can be calculated via the reference flow computed from base case. Flow reliability margin represents the margin to account for the uncertainties for the flow-based market coupling calculation process. The next subsection will give a detailed discussion about the use of reference flow, base case and FRM. The operational margin term such as FAV applied by TSOs is not included in the case study, since operational aspects are not considered in the network capacity under nodal pricing.

$$RAM = F_{max} - F_{ref} - FRM - FAV \qquad (12)$$

Where

F_{max} is the maximal allowable power flow on a critical network element
F_{ref} is the reference flow that reference flow (Fref) is the physical flow computed from the base case, which reflects the flow as a result of the exchange program outside the day-ahead exchange market in reference day
FRM is the flow reliability margin to account for the uncertainties for the flow based market coupling calculation process
FAV is the final adjustment value that represents the capacity margin reserved for operational skills and experiences that cannot be introduced into the flow-based market coupling

b) Base case and reference flow F_{ref}

Base case is a system snapshot chosen by TSOs to calculate zonal PTDF and to determine reference flow. It is the best estimate of the system state made two days before delivery. The GSK values and zonal PTDF are derived from base case analysis. In current market coupling process, parameters such as net exchange program are taken from the reference day and are adjusted with the renewable, load forecast for the delivery day. The adjustment methods differ from TSOs [30].

As noted by Schönheit et al, there are two reference flow definitions in literature [24]. It can be the base case flow that includes the flow as a result of inter-zonal trade at day-ahead market and the long-term nomination. The reference flow can also be defined as the flow incurred by intra-zonal or inter-zonal transactions outside of day-ahead market coupling such as bilateral or long-term trading [3]. In our designated joint auction rules, long-term auction schedules are financial in nature, i.e liquidated after each round. Bilateral trading submits its cross-zonal FTR schedule in the joint auction and the dispatch associated with it is also financial in the auctions prior to day-ahead. We only take into account flow incurred as a result of the intra-zonal transaction as reference flow.

In the case study, base cases are chosen to represent intra-zonal trade impact on the system at zero net position. In other words, the base case flow in the case study of this research is the reference flow, which represents the interconnection capacity usage when the generation and load are balanced within a bidding zone. Reference flow that represents the flows on critical network elements in a balanced zonal network is calculated by subtracting the reference day flow from the product of zonal PTDF and the net zonal import/export in base case.

$$F_{ref}^{l} = F_{refday}^{l} - \sum_{z} PTDF_{l,z}^{zon} NEX_z \quad (13)$$

Where

F_{refday}^{l} is the reference day flow

c) Flow Reliability Margin FRM

In day-ahead market coupling, uncertainties from capacity calculation process such as the difference between forecasted and realised net exchange program or approximation in the GSK methodology are quantified by Flow Reliability Margin (FRM). In order to take into account of uncertainties and ensure the firmness of market coupling outcome, the FRM is deducted from the interconnection capacity as shown in Equation 9. To compute FRM for day-ahead market coupling, TSOs compare the predicted flow using flow-based methodology from base case selected two days before delivery at D-2 and the observed real-time flow at day D. A distribution of the differences of these two flows from historical data are stored in a data base. With assigned risk level for delivery day, FRM value can be selected from the database and deducted from the allowed capacity of critical network elements. FRM values usually lie in the range of 5-20% of the maximal physical network capacity [30].

In the network representation, FRM value at the higher end from historical data in day-ahead market coupling, 20% of maximal capacity, is adopted for RAM calculation in long-term auction. FRM value of 5% of maximal capacity is adopted for RAM in day-ahead market. When historical data in the long-term auction becomes available, a higher FRM may be expected in this time frame compared with the day-ahead values

d) GDSK for PTDF computation

Generation demand shift keys represent the nodal change of generation or demand level in proportion to the zonal net injection/withdrawal change. Equation 10 shows that zonal PTDF on interconnection lines can be derived from nodal PTDFs and generation demand shift keys (GDSK). In the market coupling process, zonal PTDF maps the incremental change of interconnection flow with unit change of zonal net export in comparison with the base case.

Before the clearing of long-term auction and day-ahead market, TSOs who construct GDSK for simplified grid model, do not acquire supply and demand bidding information. In the case study for long-term and day-ahead auctions, uncertainties of exact location for supply, purchase bids or the absence of information for injection and withdrawal nodes of FTR bids are explicitly taken into account in the network representation methods

$$PTDF_{l,z} = \sum_n PTDF_{l,n} * GDSK_{n,z}$$

Where:

$PTDF_{l,z}$ denotes the zone to line power transfer distribution factors of zone z on interconnection line l.
$PTDF_{l,n}$ denotes the node to line power transfer distribution factors on interconnection line l.
n refers to the nodes within zone z.
Various GDSK methods have been discussed in literature and industry [31][32]. In the flow- based market coupling methodology report by TSOs in Centre West Europe (CWE), the criteria made by different TSOs to include generation in GSK is reviewed [30]. In general, power plants included in the GSK are those flexible to change output. It represents the forecast of change in generation output on critical branches in response to zonal net export/import. Several types of generators are included: gas/oil, hydro, pumped storage and nuclear.
Computation of well performing GDSK is difficult for day-ahead market and faces more methodological challenges for long-term auction. For instance, as the analysis of D'Aertrycke and Smeers shows, the linearity of GDSK plays a determinant role on the effectiveness of zonal PTDF [19]. Non-linearity of GSK occurs when generators reach capacity limits with changes in export/import level.
The predetermined GDSK is an estimation to approximate the realized dispatch in market clearing. Meanwhile, GDSK values have impact on feasible region of the market clearing. The GDSK estimation inaccuracy produces clearing outcome that generates suboptimal social welfare [5]. As the discussion in previous section points out, forecast of generation and load patterns a few years prior to electricity delivery is more challenging than the forecast for day- ahead.

6. Base case and reference flow for long-term auction

The base case is constructed by using reference day system operation state and adjusting it by deduction of flows as a result of the net exchange positions from the load. As shown in Figure 16, load at node 2 is served by self-generation at the node in reference day. The generator in zone west produces 125 MWh and there is no load within the zone. In zone east, generator at node 4 produces 300 MWh and demand level at node 3 is 425 MWh.

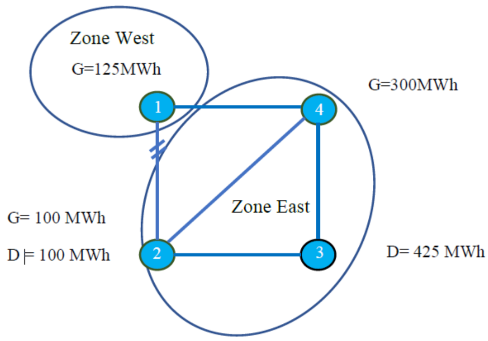

Figure 16 - Reference day transaction pattern for long-term auction

Base case used is intended in this research to approximate intra-zonal transaction impact on interconnection flow at zero net position. To compute the intra-zonal transaction pattern, net import quantity 125 MWh is deducted from the marginal load located at node 3 and result is shown in Figure 17. The interconnection flow as a result of intra-zonal transaction is 37.5MW.

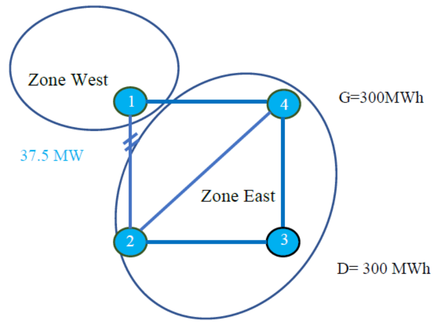

Figure 17 - Base case for long-term auction

7. Base case and reference flow for day-ahead auction

imilar to long-term auction, base case is constructed by using system operation of a reference day and deducting the flow as a result of net exchange positions. As shown in Figure 18, load is partially served by self-generation at node 2. Zone west has no load and generates 325 MWh. In zone east, generator at node 4 produces 250 MWh and demand level at node 3 is 525 MWh.

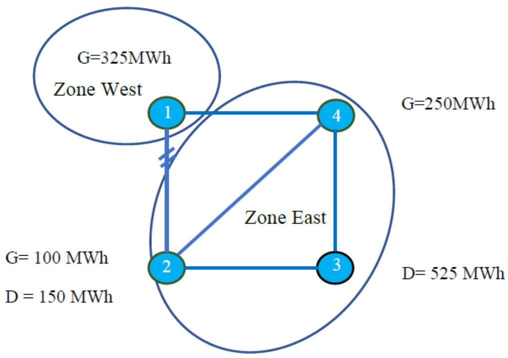

Figure 18 - Reference day interzonal transaction pattern for long-term auction

To compute the intra-zonal transaction with zero net position for the joint auction, the net import 325 MWh is deducted from the marginal generator at node 2 and load located at node
As shown in Figure 19, the interconnection flow as a result of intra-zonal transaction is 31.25MW.

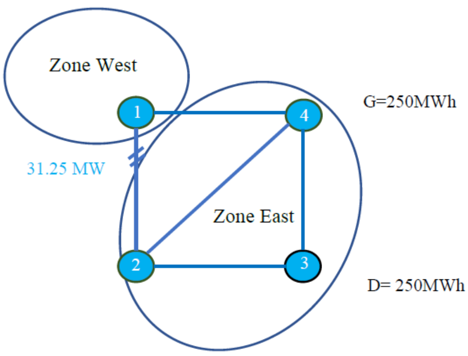

Figure 19 - Base case for day-ahead auction

8. Zonal market clearing and settlement in long-term auction

In the nodal pricing market, the hub node production or demand has a PTDF value of 0 on all network branches. Under zonal pricing, to assign PTDF value with bids in the hub zone, we assume that all the purchase and sale bids within hub zone has the PTDF value equal to zero. PTDF values of the five bidders are displayed in *Table 6*

	Capacity (MW)	**Bid 1**	**Bid 2**	**Bid 3**	**Bid 4**	**Bid 5**	**Shadow price** (€/MW)
Line 1-2	122.5	0.5625	0	0	1	0	17.78
Line 2-1	197.5	-0.5625	0	0	0	0	0
Line 1-4	400	0.4375	0	0	0	0	0
Line 4-1	400	-0.4375	0	0	0	0	0

Similar to joint auctioning under nodal pricing, dual variable of energy balance equation gives zonal price at demand zone east: 25 €/MWh. The shadow price of the inter-zonal transmission link 1-2 is given by the dual variable of the power flow constraint: 17.78 €/MW. Prices of other zones can be derived by the inter-zonal PTDF relations in equation 4 by treating zones as virtual nodes. Using equation 4, the price of FTR for bid 1 can be calculated: 10 (17.78*0.5625) €/MW. The zonal price for west zone is 15 (25-17.4*0.575) €/MWh.
With interzonal PTDF set at 0.5625 from zone west to zone east, the estimated flow as a result of cross-zonal trade on interconnection line 1-2 is 122.5 MW. Rewarded FTR to bidder 1 is 217.8 MWh and energy sale offer to bidder 3 is 300 MWh. Bidder 2 and bidder 4 do not get their bid. 300 MWh energy purchase from bidder 5 is accepted. Payment from bidders to the SO can be summarized in Table 7. Bidder 1 pays 2178 € to the SO and bidder 5 pays 7500 € to the SO. At the same time, bidder 3 receives 7500 € from the SO for its energy sale

	Bidder 1	**Bidder 2**	**Bidder 3**	**Bidder 4**	**Bidder 5**
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Upper bound (MW)	500	150	300	100	300
Lower bound (MW)	200	0	0	0	0
Bid price (€/MW)	10	35	20	10	25
Quantity	217.77	0	300	0	300
Price (€/MW)	10	0	25	0	25
Payment to SO (€)	2178	0	-7500	0	7500

Table 7 - Payment from bid winners to SO in the long-term auctioning

9. Zonal market clearing and settlement in day-ahead market coupling

The inter-zonal PTDF in the day-ahead market can be represented in Table 8. Unlike nodal pricing, the dispatch from day-ahead market clearing under zonal pricing is physical. Therefore, only supply bids by generators or purchase bids by load are allowed in the day-ahead market. Transmission right bids such as FTR or PTR are not accepted. As the demand bid is binding in day-ahead market, the lower and upper limits of demand at node 3 are set at 500 MWh in the optimization.

	Capacity (MW)	**Bid 1**	**Bid 2**	**Bid 3**	**Bid 5**	**Shadow price** (€/MW)
Line 1-2	158.75	0.55	0	0	0	9.09
Line 2-1	221.25	-0.55	0	0	0	0
Line 1-4	400	0.45	0	0	0	0
Line 4-1	400	-0.45	0	0	0	0

Generation and load payment to SO is shown in Table 9. Generation in zone west produces 288.6 MWh and generation in zone east produces 211.4 MWh. It is important to note that the 200 MW on interconnection line 1-2 is the estimated flow using assumptions such as interzonal PTDF values, reference flow and FRM at the time of day-ahead market clearing.

The shadow price of congested lines determines the price spread between zones. Zone east has a price of 20 €/MWh and line 1-2 has a price of 9.09 €/MW. The FTR between zone east and zone west is 5 (0.55*9.09) €/MWh. The price in zone west is 15 (20-5) €/MWh. Payment from generation and load to the SO is summarized in Table 9. Load in zone east pays 10000 € for the 500 MWh demand. The generator at node 4 in zone west receives 4228 €, while the generator at node 1 in zone west receives 4329 €. There is a surplus of 1443 € for the SO.

Type	**Generation**	**Generation**	**Generation**	**Load**
Zone	Zone west	Zone east	Zone east	Zone east
Quantity (MW)	288.6	0	211.4	500
Price (€/MW)	15	0	20	20
Payment to SO (€)	4329	0	4228	10000

Payment from the system operator to previous auction winners in the day-ahead market is shown in Table 10. The SOs pay 1089 € to bidder 1 who holds 217.8 MWh FTR from the long term auction and pays 6000 € to bidder 5 for holding 300 MWh energy purchase rights. Meanwhile, bidder 3 pays back the SO 6000 € for the 300 MWh of energy sale rights. The total net payment for the SO in day-ahead time frame for the previous auction winners is 1443 €. The surplus of 1443 € can cover the net payment 1089 € to bid winners in previous around. In the case study, interzonal PTDF value in the day-ahead auction is smaller than that of long- term. Therefore, the revenue adequacy for SO can be guaranteed between these timeframes.

	Bidder 1	**Bidder 2**	**Bidder 3**	**Bidder 4**	**Bidder 5**
Type	Financial transmission rights	Energy sale	Energy sale	Physical transmission rights	Energy purchase
Quantity (MW)	217.8	0	300	0	300
Price (€/MW)	5	0	20	0	20
Payment to SO (€)	1089	0	6000	0	6000

Table 10 - Payment from the SO to bid winners in day-ahead market

STUDY OF ENERGY INDEPENDENCE OF EUROPEAN COUNTRIES IN THE CONTEXT OF NEW GLOBAL SECURITY CHALLENGES

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Overview

The energy independence of the country is a fundamental component of its sovereignty. It determines the independence of one country from the energy resources of others. The European Union imports 90% of the gas it consumes. Until recently, the share of the Russian Federation in this import was 45%. This is about 140 billion cubic meters of natural gas, of which 15 billion cubic meters were supplied in liquefied form. The EU also imports about 25% of oil and oil products from Russia and 45% of coal.

A sharp rise in energy prices began in early 2021, during a heated dispute over the commissioning of the Nord Stream 2 gas pipeline. With the beginning of the full-scale Russian invasion of Ukraine on February 24, 2022, the next jump in prices took place. This rise culminated on March 7, when gas prices topped $3,800 per 1,000 cubic meters as a result of Russian threats to cut off gas supplies to Europe as a countersanction. On average, over the past six months, the price of gas has increased by 40% compared to December 2021. At the same time, the United States has banned the import of Russian energy carriers, but the European Union is not yet ready for a complete rejection of Russian energy carriers.

Energy resources have become an important geopolitical factor of Russia's influence on other countries. The oil and gas sector brings Russia half of its budget and accounts for more than half of exports. This year, Russia's income grew three times from exports to the EU thanks to exceptionally high prices for energy resources. The EU pays an average of 950 million euros per day for oil and natural gas. This amount is equivalent to the estimated cost of 160 Kalibr cruise missiles launched in Ukraine. For six months of the war, the EU paid Russia more than 150 billion euros for oil and gas. This money almost completely compensated for the impact of Western sanctions on Russia.

The war in Ukraine exacerbated the problems in the energy market and necessitated an immediate review of the strategy for the energy independence of the EU providing. Our paper examines the prerequisites for building such strategies and explores the possibilities of developing energy systems in Europe, given the significant reduction in dependence on Russian energy.

Various world organizations are engaged in research in the field of energy security and independence. At the National Technical University of Ukraine "Igor Sikorsky Kyiv Polytechnic Institute" we are also engaged in researching energy development strategies on the European continent and globally based on the application of intelligent data mining and system analysis. In order to monitor and comparative analysis of the energy independence state of different countries, a methodology (metric) for quantitative measurement of this indicator has been developed. It summarizes the characteristics of the country's energy system by such groups of indicators as the country's potential for access to fuel and energy resources; the balance between energy production and consumption; the ability of the country's energy system to develop and transition to renewable energy and energy efficiency. An integral indicator that aggregates the quantitative values of these groups of indicators is the Energy Freedom Index.

Methods

In [1] we proposed a method of a quantitative assessment of the state of energy systems of countries in the form of an integrated index Energy Freedom Index (*Ief*). The index is built using the methodology of constructing composite indicators [2]. The conditions of functioning of the energy sector of the studied countries have significant differences. To perform an effective analysis, we use data mining techniques including comparative, correlation and regression analysis. Also, the groups (clusters) of countries were built using the k-means method according to the Energy Freedom Index, so that each subset consists of similar countries.

Results

The situation shows that the countries of the European Union have been implementing the strategy of energy independence too slowly, probably because they saw an economic advantage in the use of imported Russian fuel resources. For each country, the ability to abandon Russian fossil fuels is determined by their energy systems' structure and state of development.

The proposed Energy Freedom Index of the country [1] aggregates the outlined components and is calculated on the basis of three separate sub-indices, each of which can be the object of independent analysis, namely: sub-index of energy potential, sub-index of energy balance, and sub-index of energy development. Since the factors whose influence is reflected in the outlined sub-indices (energy potential, balance and development) strengthen or weaken each other, the integrated Energy Freedom Index is defined as the product of three sub-indices (*Table 1*).

Table 1 - Characteristics of the components of the Energy Freedom Index

Component	Component characteristics	Component calculation (data sources: [3–5])	Values
1. *Sub-index of energy potential*	Determines the established potential of the country in terms of access to fuel and energy resources: coal, natural gas and crude oil reserves	The value of the total explored reserves of coal, natural gas and crude oil, determined per capita To determine the total indicator and reconcile the data, which differ both in units of measurement and in the range of values, logistic rationing of data was used	Larger sub-index values within the range [0.1; 1.5] has greater potential. Average value: 1.0.
2. *Sub-index of energy balance*	Reflects the annual balance between total production and consumption of electricity and heat in the country	The ratio of annual production and annual energy consumption (both indicators – in million metric tons of oil equivalent). The volume of energy production includes: production and processing of coal, crude oil and leasing condensate, natural gas; electricity generation at nuclear and hydroelectric power plants; geothermal electricity generation; production of solar thermal and photovoltaic electricity and wind electricity; production of fuel from wood and biomass waste	The sub-index value ≥ 1.0 means positive energy balance, the ability to meet the energy needs of the country's own production. Sub-index value <1.0 means negative energy balance
3. *Sub-index of energy development*	Demonstrates the ability of the country's energy system to develop with the possibility of energy transition	Chain growth rate of the total installed capacity of all electricity generation facilities in the country The total installed capacity of all electricity generation facilities consists of: power of fossil fuel electricity; hydraulic accumulators; hydroelectric power plants; nuclear electricity; geothermal electricity; electricity from biomass and waste; total electricity from renewable sources without taking into account hydropower. The value of the current year's sub-index is defined as a percentage of the value of the indicator for the previous year	The sub-index value of the base year 2000 = 1.0. The sub-index value ≥ 1.0 means positive dynamics of development. The sub-index value <1.0 means negative dynamics of the decline

The Energy Freedom Index was calculated for 2000-2020 and 141 countries. The conditions of functioning of the energy sector of the studied countries have significant differences. To perform an effective comparative analysis, we divide a group of countries into subsets (clusters) according to the Energy Freedom Index so that each subset consists of similar countries. The results of clustering for 2019 are presented in Fig. 1.

Energy Freedom Index, integrated for the whole period, allowed to establish similar factors, conditions and features of energy systems, which ensured countries to achieve the results defined in the study. In the leading countries, the high index was mostly provided by the high values of the energy balance sub-index and the energy development sub-index. This shows that balancing the use of energy for the needs of the economy with the ability to produce the necessary gross national product, as well as the ability to use renewable energy sources and increase energy efficiency are more important components in achieving energy independence than access to fossil fuels in energy potential.

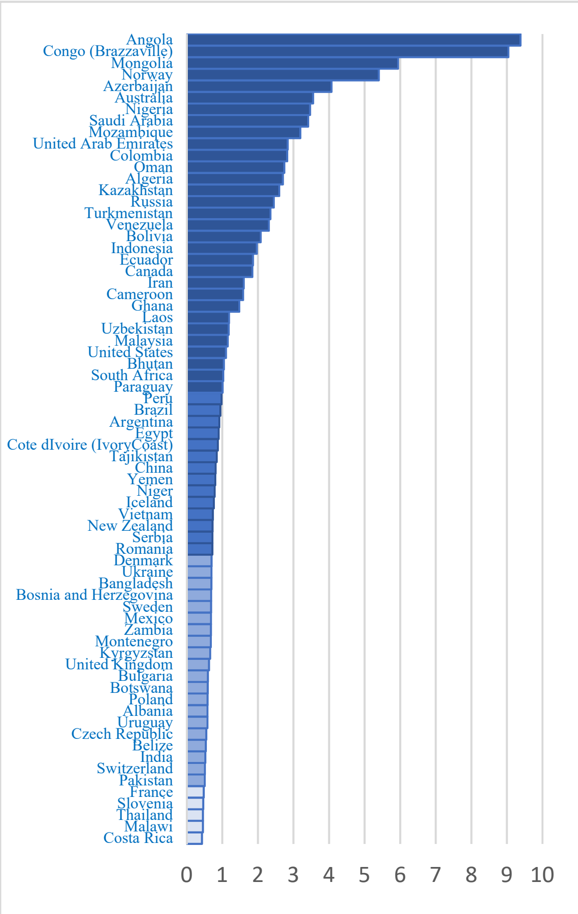


*Figure. 1***.** Energy Freedom Index Clusters, 2019

In 2020, there have been significant changes in EU economy and the electricity market in particular. Electricity consumption and imports decreased significantly, and fossil fuel use decreased accordingly. This was due to the slowdown in economic development due to the coronavirus pandemic and favorable weather conditions. The development of renewable generation (+80 TWh) and the increase in net imports (+13 TWh), mainly from Norwegian hydropower plants, also had a partial impact. In general, the carbon potential of EU electricity in 2020 decreased by 14% compared to 2019 [3; 4].

The Energy Freedom Index of the leaders of the European rating last year decreased – in Romania by 25%, in Denmark and Sweden – by 13%. Instead, for countries that have reduced fossil fuel consumption in 2020 – France, Germany, Belgium, Italy, and others – *Ief* has grown (table 1, fig. 2). The reduction in fossil fuel consumption and demand has also led to lower prices for all types of primary energy resources. Prices for coal, natural gas, and oil have been the lowest in twenty years, falling to 2000 levels.

In 2021, the EU was hit by an energy crisis. On the one hand, the post-pandemic economic recovery has increased natural gas consumption – in the EU as a whole by 4% compared to 2020. In particular, Slovakia increased gas consumption by 25%, Estonia – by 17%, Spain – by 13%, Italy – by 8%, France – by 3%, Germany – by 5%. Only some countries have managed to reduce natural gas consumption. In particular, the Netherlands reduced gas consumption by 13%, Sweden – by 31%, Finland – by 23%, Lithuania – by 18%

*Figure 2***.** Energy Freedom Index of the European countries, 2020

For addition analysis and to eliminate the index spikes the coefficients for the slope of the *ief* trends were considered. Only three European countries (Ireland, Albania, Estonia) have a confident positive value of this coefficient (>0.01). In other hand seven European countries (Poland, Bosnia and Herzegovina, UK, Netherlands, Norway, Lithuania, Denmark) show negative trends with the coefficient less then -0.01. It is also worth mentioning the growing instability of the European energy sector.

Table 2. Ranking of the EU and Ukraine by the value of the Energy Freedom Index and the relationship between the index and the share of energy imports from Russia in the structure of their national consumption [3

				***Ief* 2020 components**				
Place in the EU ranking 2020	**Country**	***Ief* 2019**	***Ief* 2020**	**Subindex of energy potential**	**Subindex of energy balance**	**Subindex of energy development**	**Share of imports from Russia in national consumption**	**Correlation between *Ief* and the share of imports from Russia**
1	Ukraine	0.70	0.77	1.07	0.72	1.00	NA	NA
2	Bulgaria	0.59	0.76	1.00	0.69	1.11	0.40	0.20
3	Poland	0.58	0.63	1.05	0.59	1.01	0.37	-0.85
4	Denmark	0.70	0.61	0.95	0.98	0.65	0.16	-0.65
5	Czech Republic	0.55	0.59	1.00	0.63	0.94	0.24	-0.43
6	Sweden	0.68	0.59	0.94	0.63	1.00	0.08	0.57
7	Latvia	0.18	0.56	0.94	0.64	0.93	0.31	-0.29
8	Slovenia	0.47	0.55	0.97	0.55	1.03	0.10	0.10
9	France	0.48	0.54	0.94	0.58	0.99	0.09	-0.10
10	Romania	0.72	0.54	0.95	0.72	0.78	0.18	-0.58
11	Finland	0.42	0.49	0.94	0.52	1.00	0.45	0.09
12	Croatia	0.36	0.43	0.95	0.45	1.00	0.09	-0.08
13	Hungary	0.35	0.42	0.99	0.40	1.05	0.54	-0.28
14	Slovakia	0.32	0.40	0.95	0.41	1.03	0.60	-0.28
15	Germany	0.33	0.37	1.01	0.37	0.98	0.28	-0.65
16	Austria	0.35	0.32	0.94	0.42	0.82	0.03	0.10
17	Netherlands	0.39	0.32	0.95	0.35	0.95	0.55	-0.58
18	Portugal	0.23	0.31	0.94	0.35	0.94	0.05	0.49
19	Ireland	0.31	0.28	0.94	0.26	1.14	0.53	0.94
20	Greece	0.25	0.28	0.99	0.32	0.90	0.03	0.30
21	Spain	0.26	0.28	0.95	0.28	1.04	0.08	-0.39
22	Belgium	0.22	0.26	0.94	0.26	1.06	0.29	0.25
23	Italy	0.21	0.24	0.94	0.25	1.00	0.25	0.53
24	Lithuania	0.10	0.13	0.94	0.13	1.10	0.98	0.13
25	Estonia	0.18	0.10	0.94	0.11	1.01	0.16	-0.79
26	Luxembourg	0.03	0.05	0.94	0.05	1.00	0.03	0.36
27	Cyprus	0.04	0.05	0.94	0.05	1.03	0.05	-0.41
28	Malta	0.01	0.01	0.94	0.01	1.00	0.17	0.03

For further research, a pairwise correlation analysis was conducted to determine the relationship between the Energy Freedom Index, which is a generalized measure of the country's ability to embargo, and the share of imports of Russian energy in its total consumption, which is a measure of dependence on Russia (*Figure*. 4)

The correlation coefficient is interpreted as follows:

1. Positive coefficient: the growth of the Energy Freedom Index is associated with the growth of energy imports from Russia; the decrease in the Energy Freedom Index is associated with a decrease in energy imports from Russia;

2. Negative coefficient: the growth of the Energy Freedom Index is associated with a decrease in energy imports from Russia; the decrease in the Energy Freedom Index is associated with the growth of energy imports from Russia.

The density of the relationship between variables in the interval [0; ±0,1) – absent, in the interval [±0,1; ±0,3) – low, in the interval [±0,3; ±0,5) – medium, and in the interval [±05; ±1] – high.

Based on the results of the analysis, it is possible to group countries on the basis of the relationship between their energy freedom and the share of Russian energy imports as follows.

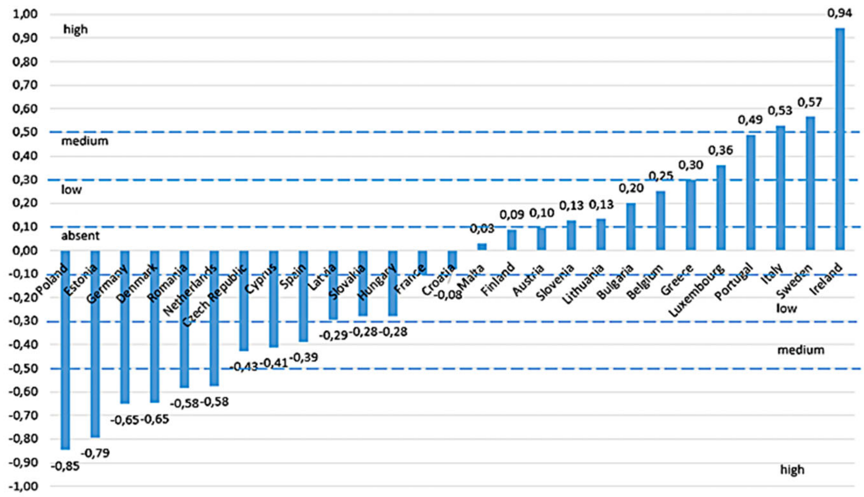


Figure 4. Correlation coefficient and density of the relationship between the Energy Freedom Index (*Ief*) and the share of imports of Russian energy in the structure of their total consumption (*Imrf*) for the UE countries, 2000-2020

Countries with a high and medium density of the inverse relationship between their energy freedom and the share of imports of Russian energy (Poland, Estonia, Germany, Denmark, Romania, the Netherlands, the Czech Republic, Cyprus, and Spain – for these countries the decrease in the Energy Freedom Index is associated with the growth of energy imports from Russia).

Countries with a low level of direct and inverse relationship between their energy freedom and the share of imports of Russian energy (Latvia, Slovakia, Hungary, Slovenia, Austria, Belgium, and Lithuania – for these countries the dynamics in the Energy Freedom Index is very weakly associated with the dynamics of energy imports from Russia).

Countries for which the relationship between their energy freedom and the share of imports of Russian energy has not been established (Croatia, France, Malta, and Finland — for these countries the dynamics in the Energy Freedom Index is not associated with the dynamics of energy imports from Russia);

Countries with a high and medium density of direct relationship between their energy freedom and the share of imports of Russian energy (Greece, Luxembourg, Portugal, Italy, Sweden, and Ireland – for these countries the growth of the Energy Freedom Index is associated with the growth of energy imports from Russia, and the decrease in the Energy Freedom Index is associated with a decrease in energy imports from Russia).

Among the established groups of countries, only the first can show that for these countries, increasing dependence on energy imports from Russia may reduce the level of their energy independence and vice versa. The rest of the groups have either a weak and no correlation between variables, or results that contradict the hypothesis about the nature of the relationship between the energy freedom of countries and energy imports from Russia.

Thus, the correlation analysis does not allow to clearly identify patterns of dependence of countries on energy imports from Russia and to determine which of them are willing to abandon such imports and take measures to reduce this dependence.

Another approach to grouping countries takes into account the risk of refusing to import energy resources. The grouping of countries in the two-dimensional field of parameters – Energy Freedom Index (*Ief*) and the share of imports of Russian energy resources in the structure of total consumption (*Imrf*) – provided an opportunity to distribute countries according to the level of risk. According to the results for 2020 counties were grouped as follows (Fig. 5).

In the high-risk zone (HR) were countries whose index is below average, and which have more than half of Russian energy resources in the structure of total consumption: *Ief* < 0.50, *Imrf* > 0.50 (Greece, Lithuania, Netherlands, Slovakia, and Hungary).

In the medium-risk zone (MR) were countries whose index is below average, but which have less than half of Russian energy resources in the structure of total consumption: *Ief* < 0.50, *Imrf* < 0.50 (Austria, Belgium, Estonia, Ireland, Spain, Italy, Cyprus, Luxembourg, Malta, Germany, Portugal, and Croatia).

In the low-risk zone (LR) were countries whose index is above average, and which have less than half of Russian energy resources in the structure of total consumption: *Ief* > 0.50; *Imrf* < 0.50 (Bulgaria, Denmark, Latvia, Poland, Romania, Slovenia, France, Czech Republic, and Sweden).

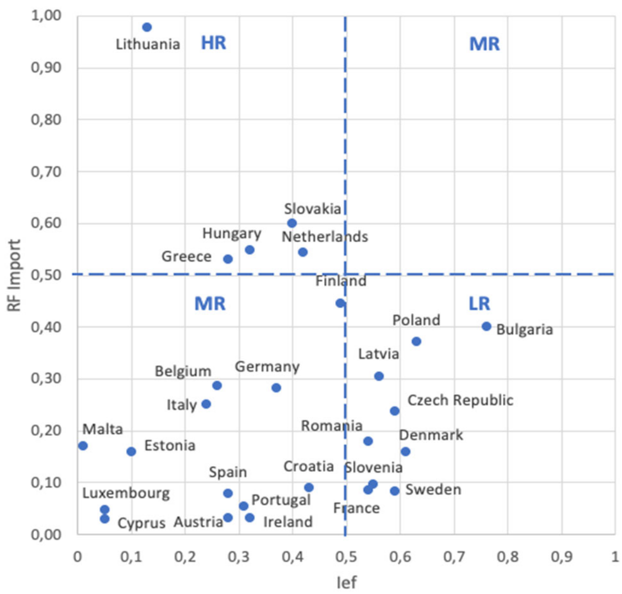
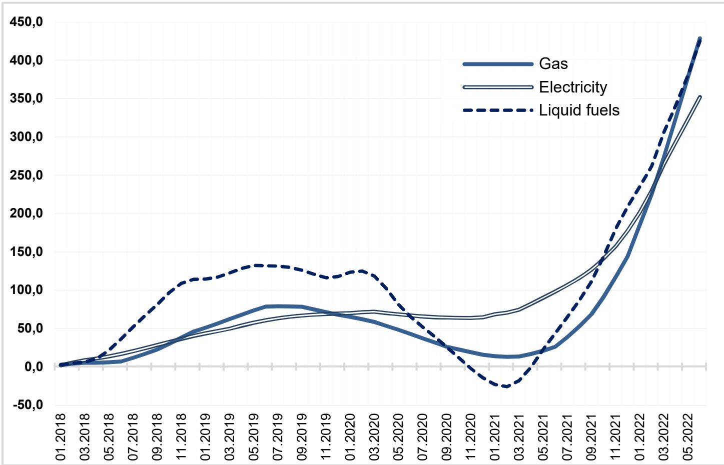


Figure 5 - The grouping of countries in the two-dimensional field of parameters – Energy Freedom Index (*Ief*) and the share of imports of Russian energy resources in the structure of total consumption (*Imrf*), 2020

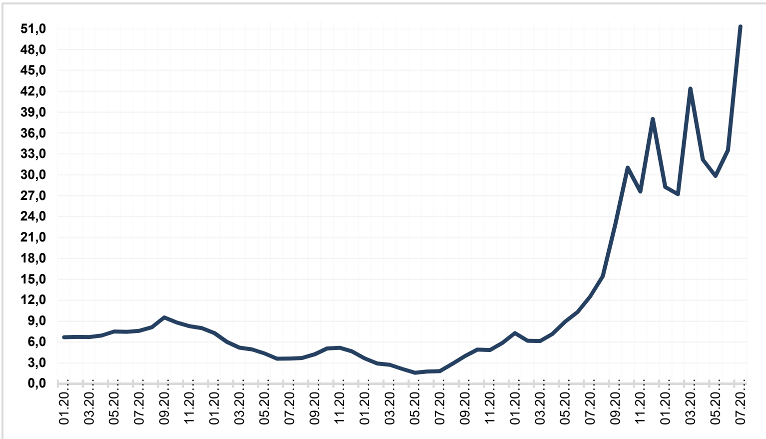
In 2021, the EU was hit by an energy crisis. On the one hand, the post-pandemic economic recovery has increased natural gas consumption – in the EU as a whole by 4% compared to 2020. In particular, Slovakia increased gas consumption by 25%, Estonia – by 17%, Spain – by 13%, Italy – by 8%, France – by 3%, Germany – by 5%. Only some countries have managed to reduce natural gas consumption. In particular, the Netherlands reduced gas consumption by 13%, Sweden – by 31%, Finland – by 23%, Lithuania – by 18%. On the other hand, the EU's own natural gas production decreased even more - by 13% compared to 2020. Quarterly production became lower than in the period 2015-2019 [6]. This showed that the reduction in domestic gas production in the EU is a long-term trend.

The full-scale Russian invasion of Ukraine at the end of February 2022 significantly affected the situation in the European energy market. Prices have risen unprecedentedly and consumption has fallen. Russia's average fossil fuels export prices in 2022 were about 60% higher than last year (fig. 6). According to forecast data, in 2022 the demand for natural gas is expected to decrease by about 6%, which will correspond to the level of 2020 [7].

The dynamics of the energy independence index of countries such as Hungary, Germany, Slovakia, Ireland, Spain, etc., indicates the presence of energy potential, but their energy balance is low and energy development is slow. Lack of activities to increase energy independence, post-pandemic economic recovery and growing dependence on imported fuels have led to an energy crisis in these countries. Countries that had a high index, on the other hand, have greater opportunities to reduce their dependence on Russian fossil fuels.



(a) Energy prices, 01.2018 – 07.2022, annual rate of change



(b) Natural gas price, 01.2018 – 07.2022, USD per 1 million BTU

Figure 3 - Energy prices dynamics

In 2021, the European Commission developed a program of gradual abandonment of Russian gas imports – Fit for 55. It presented a set of legislative proposals and initiatives to ensure that EU policies are in line with climate goals, but was rather slow, with a deadline of 2050. After the start of the war and the aggravation of the situation in the energy market in 2022, the European Union began to develop new plans to eliminate dependence on Russian fossil fuels. Among them:

– *REPowerEU* – a preliminary plan to eliminate dependence on Russian fossil fuels by 2030. According to it, it is expected to reduce EU demand for Russian gas by 100 billion cubic meters or two-thirds of the total by the end of 2022 [8];
– *A 10-Point Plan to Reduce the European Union's Reliance on Russian Natural Gas* – a more detailed plan presented in March 2022 by the International Energy Agency [9];
– *Save Gas for a Safe Winter* – new European gas demand reduction plan to prepare for supply cuts and reducegas use in EU by 15% until next spring [10].

The EU estimates that a complete shutdown of Russian gas imports could lead to a gas shortage of 30 billion cubic meters by March next year. June 2022 marked the first month in history that the EU imported more gas through LNG terminals from the US than through pipelines from Russia. The fall in Russian supply requires the efforts of the EU countries to reduce the demand for Russian energy resources in the winter. As of September, this year, EU countries have already accumulated 85% of gas in their gas storage facilities. Some European countries, including Poland and the Baltic states, have already prepared for the possibility of a complete reduction. In general, the updated energy supply programs of the EU countries envisaged by the above-mentioned acts are based on three main directions:

The first direction is to save energy and reduce the demand compared to the previous years' consumption. In particular, it is planned a 15% reduction between 01.08.2022 to 31.03.2023.

The second direction is to diversify supplies and attract more renewable gas sources. In particular, it is planned to increase LNG imports.

The third direction is to accelerate the transition to production and use of clean energy. In particular, it is planned to install photovoltaic panels on the roofs of residential buildings and enterprises, to double the speed of installing heat pumps.

The commission also outlined measures to respond to rising energy prices in Europe and replenish gas supplies next winter. By the end of this year, about 25% of electricity can be generated by solar energy. In general, by the end of 2022 it is expected to reduce EU demand for Russian gas by 100 billion cubic meters or two-thirds of the total volume.

As for the first direction, energy efficiency and reduction of energy consumption are the most realistic measure in the short term. The most recent development of the European Commission focuses on avoided consumption. This approach is indicative of the fact that alternative supply options have now been more or less exhausted and in the event of total disconnection from Russian gas, the only way to avoid energy shortages in the EU this winter is through actions on the demand side.

The implementation of the plan according to the second direction on diversifying fuel supplies and attracting renewable gas sources is designed for five years. The energy crisis of 2021 exposed problems in the European energy system, such as limited gas transportation capacity, unsuitable geographical location or insufficient length of gas pipelines, the lack of LNG terminals and seaports in some countries, and the inability of the current level of renewable energy to meet energy needs.

In the context of the third direction, we note that more than 20% of energy in the EU is currently produced by renewable energy sources and 50% by nuclear reactors. Thus, about 70% of European electricity has already been decarbonized. The European Commission proposed to increase the share of electricity from renewable sources to 45% by 2030. The most effective way to implement this plan is direct electrification of final consumption using renewable energy sources. At the same time, the planned construction of 14 new nuclear reactors in Europe, in particular in France, will not increase the share of electricity produced by nuclear energy in connection with the gradual decommissioning of existing reactors, the technical resource of which is exhausted. This share will remain at the level of 50% in 2035-2050.

All EU countries are taking active measures to replace Russian fuel with energy from other sources. However, as shown above, the level of their readiness and the time of replacement is different and are determined by the level of dependence, policies, and capabilities of countries. Different countries will have different consequences of the embargo on Russian fossil fuels, measured by losses in the country's economy and security. All of the abovementioned approaches to countries grouping do not take into account the measures taken by the countries to reduce dependence on energy imports from Russia (which in this case oppose risky measures), so they cannot be used to measure final risk and determine their readiness for the embargo. In addition, the country's readiness to implement the proposed EU embargo is largely determined by its political interests. To this end, the countries were analyzed in the context of a set of measures they took to eliminate Russian dependence and preparedness for the embargo. To date (since the countries are in the process of making final decisions), four groups of countries can be identified according to the degree of their readiness to replace Russian energy sources and impose an embargo:

Group 1 – countries for which the refusal to import fuel resources from Russia threatens the greatest losses in the economy, and which need and may receive a delay in the imposition of embargoes (Hungary, Czech Republic, Slovakia and Bulgaria);

Group 2 – countries that are heavily dependent on fuel imports from Russia, and at the beginning of the sixth package of sanctions have some controversy over the imposition of the embargo (Netherlands, Austria, Germany, Romania, France);

Group 3 – countries that have significant or moderate dependence on imports of fuel imports from Russia, but support the embargo (Lithuania, Belgium, Italy, Finland, Poland);

Group 4 – countries that have low dependence on fuel imports from Russia and support the embargo (Greece, Estonia, Ireland, Spain, Cyprus, Luxembourg, Malta, Portugal, Slovenia, Denmark, Latvia).

Measures envisaged by the strategy of elimination of EU dependence taken by certain countries (anti-risk measures) can be divided into four categories: diversification; use of clean energy; reduction of energy consumption; the increase of own energy production and (or) construction of own LNG terminals.

In response to changes in the gas supply strategies of the EU countries, oil suppliers also are beginning to review their own strategies and change forecasts for the coming periods. Thus, on October 5, 2022, the 33rd meeting of the ministers of OPEC countries and non-OPEC partner countries was held at the Secretariat of the Organization of Petroleum Exporting Countries in Vienna, as a result of which a decision was made to reduce total production by 2 million barrels per day compared to the required levels as of August 2022, starting in November 2022. The decision concerned the members of the organization and partner countries (OPEC+). Among the reasons that led to the introduction of such restrictions can be noted:

- the recovery of global oil demand growth after the pandemic is slower than previously expected;
- the need to adjust the balance of oil supply and demand on the world market;
- the need to regulate oil prices;
- informal and tacit economic support of Russia.

Experts, analyzing the decision of OPEC +, do not consider its consequences critical for the general market, pay attention to the following factors [11]:

- quotas for oil production, which are supposed to be reduced, have not been fully used by the countries included in the cartel previously;
- a bad sign for oil traders is the slowdown in the development of developed countries and China - during a recession, and even with high hydrocarbon prices, oil consumption is significantly reduced (the level of oil consumption in 2019 has not yet been reached);
- developed countries and China, against the background of the expected increase in oil prices, are trying to find additional opportunities to supply oil to the markets. A review of the oil and oil products supplier market is expected in the direction of increasing the role of Latin American countries;
- the long-term excess of oil production over its consumption contributed to the formation of significant reserves. Today, strategic oil storages around the world contain about 4.35 billion barrels of oil – more than 14 months of covering the current deficit.

Nevertheless, experts agree that the decision to reduce the total production of oil by the OPEC+ countries is beneficial for Russia, which will have the opportunity to increase its income from the export of fossil fuels and thus receive more money to finance the war against Ukraine.

The USA quickly reacted to this decision of the OPEC+. According to the instructions of Joe Biden, the US Department of Energy will put an additional 10 million barrels of oil from the SPR strategic oil reserve on the market already in November, and the possibilities of further increasing oil production are also being rapidly studied. The US President's Administration will also consult with Congress on additional tools and powers to reduce OPEC+'s control over energy prices and maintain global energy security.

The world's largest economies, which are part of the G7, began to develop a plan to limit the price of Russian oil, which is sold around the world, even before the announcement of the OPEC + oil production limit. This restriction will not allow Russian cargo carriers to sell oil that exceeds a certain, as yet undefined, limit. As a result, Russia would be deprived of a significant part of its oil revenues.

The U.S. Department of the Treasury estimated that capping the price of Russian oil internationally would result in annual savings of $160 billion (€165 billion) for the 50 largest economies, which could encourage other countries to support the G7 initiative [12]. However, if the restriction leads to unintended consequences, such as onerous disruptions to maritime transport, sudden price shocks or total supply shortages, the decision could provoke a backlash from major economies, particularly China.

Conclusions

Global challenges of the world economy and the continuation of its functioning in conditions of uncertainty strengthen negative forecasts regarding further development. Significant geopolitical risks are added to the problems caused by the coronavirus pandemic, which only exacerbate the above-mentioned problems and become drivers of the structural restructuring of international markets.

The full-scale invasion of Russia on the territory of Ukraine on February 24, 2022, provoked the need for the leaders of all developed countries to define a clear position regarding the current situation, as well as to make a number of strategic decisions that may negatively affect the further economic development of these countries. Such decisions relate mainly to the resource provision of countries and the need to diversify the structure of suppliers with the gradual complete rejection of Russia as one of the key suppliers of resources. And if the majority of the countries of the European Union recognized that the refusal to import Russian gas is not a quick solution and should be gradual, then the EU plans to introduce a full embargo on the import of Russian oil by the end of 2022. In anticipation of such changes, other market participants of oil suppliers are beginning to review their own strategies and change forecasts for the coming periods.

In this paper, a global assessment of energy independence level for a large group of world countries is carried out. It is presented as the Energy Freedom Index, which aggregates the potential, balance, and development of the country's energy sector.

The results of calculations and clustering of countries of the world according to the Energy Freedom Index showed significant differences in the functioning and levels of energy sectors. Ukraine's ranking among the third cluster countries with an average value of the energy independence index, which also includes Poland, Romania, the Czech Republic, and Bulgaria, indicates high import dependence, unbalanced use of energy potential, low energy efficiency, and renewable energy use compared to leading countries. At the same time, Ukraine demonstrates a decrease in the level of use of traditional energy sources and the presence of prospects for development in the field of energy innovation and energy generation from renewable sources. The created index can be the basis for building scenarios and strategies for the development of energetic sectors in the world during foresight research on different time horizons.

Analysis of the energy independence of the European Union, after the Russian military intervention in Ukraine, showed significant negative consequences. The inflexible and multi-vector energy policy of industrialized EU countries, and their underutilization of energy potential, including the development of renewable energy, and low energy balance have led to import dependence on one energy supplier, and limited opportunities to use their own energy sources. The consequence of such an imbalance is the economic dependence of countries with developed economies on the Russian Federation, which has a predominantly raw-materials-based economy.

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HOW SUSTAINABLE IS COGENERATION? A LONG-TERM, REAL-LIFE EVALUATION

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Overview

Cogeneration (or "Combined Heat and Power", CHP), is spreading worldwide more and more. What are the causes of such a success? First of all, of course, the incentives granted by many States, which have at last acknowledged the importance of this technology for the overall energy efficiency.
It is then natural to wonder which of the technologies available for electricity production are best suited to be employed in cogeneration: the answer to this question may provide guidance both to installation designers who have to choose a technology for a specific application, and to policy makers who are responsible for allocating public subsidies.

Methods

More than six hundred generating units, of different technologies (gas turbines, internal combustion engines, steam turbines etc.) were analysed. For each generating unit, "real life" operation data were collected for years 2011 to 2019 (more than 12.000.000 equivalent operating hours); based on those data, a few efficiency indicators were calculated as weighted averages for each technology (Table 1). Indicators include: electric efficiency; thermal efficiency; overall efficiency; Power to Heat Ratio (PTOH); Primary Energy Savings index (PES); equivalent operation hours (Heq); load factor.
Statistical correlation among indicators was also investigated for each technology (example in Table 2); this includes, i.a.:
- correlation between equivalent operating hours and electric efficiency;
- correlation between equivalent operating hours (Heq) and load factor (Fc);
- correlation between equivalent electric efficiency and commissioning year;
- correlation between electric efficiency and thermal efficiency.

Electric, thermal and overall efficiency
Electric efficiency is the ratio of electricity produced by the CHP unit in a given year to energy (fuel) consumed to do so.
Thermal efficiency, on the other hand, is the ratio of heat produced by the CHP unit in a given year to energy (fuel) consumed to do so.
Overall efficiency is the sum of the above efficiencies.

The "Power to Heat Ratio" (PTOH)
Power to Heat Ratio (PTOH) is the ratio of electricity to useful heat, produced by a CHP unit in a given year.
A CHP unit with a high PTOH produces a larger amount of "valuable" energy (electricity) than a unit with a lower PTOH.
A high PTOH indicates that the heat carrier (e.g., steam) was exploited efficiently, as it produced a significant amount of electricity before being further used for thermal purposes.

The "Primary Energy Saving Index" (PES)
Primary Energy Savings index, or PES, is an estimate of the amount of fuel that was saved by producing electricity and heat jointly, as compared to producing them separately.

Equivalent operating hours; load factor
Modes of operation have been taken into account by means of two different quantities.
For each generating unit, the *equivalent* operating hours (Heq) have been calculated, by dividing the annual electricity production by the unit power. Heq is the number of hours during which the generating unit would have been in operation, if it had constantly been kept at maximum load.
H_{eq} was in turn divided by the *actual* yearly operating hours (H_{eff}). This yielded the "load factor" (F_c), always less than one.

$$F_c = \frac{H_{eq}}{H_{eff}}$$

H_{eq} is a sound indicator of how constant the operation was: when close to one, it suggests that the generating was operated in the proximity of full load and with few starts and stops.
In such a favourable operating mode, close to design conditions, the performance of the unit (the efficiency, in particular) is high.

Conversely, a low H_{eq} indicates that starts and stops have been numerous. Indeed, it is highly unlikely for a generating unit to be kept in constant operation during few months of the year, and to be constantly shut down during the remaining ones. Frequent starts and stops are a more realistic scenario.
When this is the case, no indications can be drawn from H_{eq} as to the duration of operating periods,: it is impossible to tell if the unit has been operated few hours at full load, or many hours at partial load.
This is where the load factor turns out to be of use. If it is close to one, the generating unit was kept close to full load, irrespective of the overall duration of operation. This also means that starts and stops –which were numerous, as seen above- took place rapidly: as a result, heat dissipation, which is often unavoidable during starts and stops, was limited.

Results

Technology			Electric efficiency (p.u.)	Overall efficiency (p.u.)	Load factor (p.u.)	Equivalent hours {%)	PTOH
ORC			0,13	0,23	0,94	86,23	1,40
ORC	SMALL SCALE		0,17	0,71	0,73	58,53	0,30
Microturbine			0,30	0,82	0,45	34,19	0,59
Microturbine	SMALL SCALE		0,26	0,71	0,58	47,55	0,58
Microturbine	SMALL SCALE	MICRO	0,19	0,69	0,79	43,36	0,37
Internal Combustion Engine			0,41	0,70	0,89	66,59	1,40
Internal CombustionEngine	SMALL SCALE		0,36	0,72	0,86	63,82	1,00
Internal CombustionEngine	SMALL SCALE	MICRO	0,28	0,83	0,87	54,76	0,51
Gas turbine			0,32	0,82	0,84	71,27	0,64
Gas turbine	SMALL SCALE		0,29	0,73	0,74	62,47	0,67
Back-pressure steam turbine			0,17	0,89	0,83	76,75	0,23
Back-pressure steam turbine	SMALL SCALE		0,10	0,72	0,88	77,48	0,15

Table 1: Weight-average efficiency indicators

Internal Combustion Engines (ICE) above 1 MW feature very high Power to Heat Ratio (PTOH) and electric efficiency. However, both quantities decrease with engine power. Only overall efficiency, which is already good for big engines, increases even more as capacity decreases.
Irrespective of engine power, load factor Fc is high, even if Heq is low. This suggests that ICEs can be -and are- started and stopped rapidly, which keeps the duration of partial load operation very short.
In particular, micro ICEs show a very strong, inverse relationship between electrical efficiency and thermal efficiency (Table 2): this suggests that the amount of heat wasted is low, or can be made low by appropriate installation arrangements.
Regardless of engine power, electric efficiency is not significantly dependent on the year of commissioning.
Unlike ICEs, gas turbines have a good (below 1 MW) or excellent (above 1 MW) overall efficiency, but a rather low electric one. The latter seems to be an intrinsic characteristic of larger turbines: above 1 MW, electric efficiency does not depend significantly on the equivalent operating hours (Heq). On the other hand, below 1 MW a positive correlation exists, which suggests that these (comparatively small) turbines are best suited for continuous operation.
PTOH, too, is generally lower for gas turbines than for ICEs (exception: ICEs below 50 kW).
Gas turbines also seem to have reached technological maturity: electric efficiency is virtually independent of commissioning year.

Steam turbines feature low electric efficiencies and PTOH; load factor, although quite high, is not very significant, since it is associated with high equivalent operating hours (Heq). Only overall efficiency is good. The tendency to suffer from load variations (low load factor) is confirmed (at least for the small-scale ones) by a strong direct correlation between equivalent operating hours (Heq) and electric efficiency. This is consistent, incidentally, with another strong direct correlation (affecting all steam turbines, irrespective of power): that between load factor (Fc) and equivalent operating hours (Heq). Apparently, these turbines have long starting times (the most probable cause of low Heq), and are therefore not much suited to intermittent operation.

Technology	Equivalent hours	Correlation	Beta1		
ORC	20.508,29	0,9464	16,4855	SMALLSCALE	
Back-pressure steam turbine	21.299,81	0,6396	2,6856		
ORC	22.664,59	0,2469	1,6724		
Microturbine	2.995,30	1,0000	1,2823		
Gas turbine	33.203,15	0,6383	0,7043	SMALLSCALE	
Micro turbine	210.596,76	-0,0805	-0,2590	SMALLSCALE	
Micro turbine	3.798,21	-1,0000	-0,8651	SMALLSCALE	MICRO
Gas turbine	888.689,24	-0,2405	-0,9345		
Internal Combustion Engine	7.686.875,20	-0,3559	-1,0228		
Internal Combustion Engine	2.639.782,05	-0,4219	-1,1473	SMALLSCALE	
Back-pressure steam turbine	27.114,65	-0,5378	-1,2971	SMALLSCALE	
Internal Combustion Engine	504.311,93	-0,9398	-2,3422	SMALLSCALE	MICRO

Table 2: Correlation between electric efficiency and thermal efficiency, for each technology

Conclusions

Internal Combustion Engine appears to be the technology which is best suited for high efficiency cogeneration: it is able to continuously adjust to load variations and, above 1 MW, features high PTOHs and efficiencies (although PTOH and electric efficiency tend to decrease with engine power).
For micro-ICEs, statistical analysis shows that low electric efficiency can be compensated by high thermal efficiency; this is yet another proof of overall high performance for this technology.
ICE is to be regarded as a mature technology, as electric efficiency has not increased significantly in almost a decade.
Gas turbines are somehow less performant: they tend to have lower electric efficiency and Power to Heat Ratio PTOH. No significant improvement in electric efficiency is to be expected from technological progress. However, for turbines below 1 MW a more regular operation might be beneficial.
Steam turbines are less than satisfying, due to their low electric efficiency and PTOH, and poor aptitude to variable load operation. Statistical analysis shows that frequent starts and stops may hinder the full exploitation of the turbine (low load factor Fc). This suggest (or confirms) that steam turbines need long times to reach full load after start up, which is an evident operational drawback as compared to gas turbines or internal combustion engines.

All assessments are based solely on the author's personal opinion.

THE PRICE OF GAS IN EUROPE: TOWARD AN EPOCHAL CHANGE

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A dramatic year is coming to an end for the world and in particular for Europe, hit by an energy crisis that has no reference to the past.

The invasion of the Ukrainian Republic by Russia, engaged in a geopolitical design to reconquer the spaces of the former Soviet Union, has had profound consequences on the European Union's supply system, which has found itself in conditions of extreme insecurity and vulnerability, also because in recent years all the attention had focused on decarbonization policies to the point of prefiguring "Zero Emissions" scenarios to be implemented as soon as possible.

in the 2015-2018 period of moderate economic growth, the prices of gas imported into Europe on the basis of long-term contracts, widely representative of the market, had remained constantly below that of oil, guaranteeing its competitiveness and with a less volatile trend than that of oil and derivatives.

In particular, the European gas market had not faced particular crisis situations other than the problems related to the seasonality of demand that have always been faced with the storage system.

Especially in the period 2015-2018, in which the price of oil had shown a strongly increasing profile up to 80 dollars per barrel, the price of gas, even if rising, had developed at a lower rate to widen the differential between the two sources up to about 20 $/barrel

The outbreak of the pandemic at the beginning of 2019, with the collapse of the oil price motivated by the strong restrictions on mobility, had led to a temporary situation of disadvantage of gas which had again turned into an advantage in the course of 2020 with the gradual recovery of economic activities

In 2021 the scenario natural gas with a share equal to 24% of the total EU needs, had reached the end of an evolutionary process that began in the 80s, which has made it a leading source in all sectors of use outside the automotive sector.

Starting from this basis, in the first half of 2021 the gas market had to face the first signs of a crisis linked to an unsatisfactory supply system from the point of view of security and diversification of supplies. In recent years, domestic production has fallen sharply, amounting to about 11.2% of total consumption, and the growth in imports, to the remaining 88.8%; in physical terms, 340 billion cubic meters.

The situation is made even more difficult due to the dominance of gas pipelines with a weight of 76.0% and with a totally unbalanced breakdown by country in favour of Russia: 50% in the case of Germany, 40% in the case of Europe.

The prospect of an orderly transition from fossil fuels to renewables has become difficult when demand recovers after the terrible experience of the pandemic. The emergence of some problems in the growth of renewables, lower nuclear inputs, accelerated decline in European oil and gas production have enormously increased the pressure on imported gas that has found itself in the position of supplier of last resort.

The fracture with the past begins in the spring of 2021, when a series of factors that alter the consolidated balances occur almost simultaneously. First of all, the demand for gas is experiencing a surge motivated not only by the post-covid economic recovery, stronger than previously thought, but also by lower contributions of nuclear power plants in operation for decades, hydroelectricity linked to low rainfall and lower wind. These elements have led to a jump in demand for thermoelectric uses, destined instead, according to climate policies, to reduce rapidly.

Faced with this new situation, there has been a historic change of attitude on the part of Russia. This country, which came to control 50% of Europe's gas imports and about 40% of its own needs in conjunction with the strong recovery in gas demand, began a policy of supply control to increase its revenues to support a policy of expansion of its role in the world, which had already had a precedent in the reconquest of Crimea.

This change has profoundly changed two fundamental features of the international gas market: that of trust between buyer and seller and that of price and supply stability that had been the basis of the large pipe supply contracts between Russia and most European countries, including Germany and Italy in the first place.a.

The turning point in trade policy but, in reality, in Russia's foreign policy, has taken place gradually limiting first gas flows directed to the spot market concentrated on the Dutch TTF HUB just when demand was also increasing to fill storage in view of the 2021-2022 winter season.

Subsequently, supplies to Europe and mainly to Germany through the Nord-Stream gas pipeline were progressively interrupted until a mysterious attack destroyed an underwater section of this vital infrastructure. The consequences of the conflict on the European gas market have been devastating with a very serious impact on economic activities and the rate of inflation.

The consequences of this policy on prices have been immediate and very significant with the overtaking, never before, of gas prices over those of oil, both expressed in a single unit of measurement, in this case the dollar per barrel. Due to the increased responsiveness of the spot market to any change in supply or demand, spot gas prices on the FTT market in July 2021, overtook the average price of long-term contracts.

A completely new situation that has marked a deep fracture with an unsustainable past on an economic, industrial and strategic level, to be replaced with a new supply model.

The confirmation of the need for a radical change in the European gas supply system came from the dramatic developments of the first part of the current year with the Russian invasion of Ukraine in execution of a geopolitical design to reconquer the economic and political spaces of the former Soviet Union.

Russian aggression has pushed Western countries, which have intervened in support of Ukraine, to adopt economic and financial sanctions. In retaliation, Russia has intensified control on the gas supplies to push European countries to accept the "fait accompli" according to the model tested during the invasion of Crimea.

In implementation of this strategy, Russian supplies to Europe and mainly those directed to Germany through the Nord-Stream gas pipeline were progressively interrupted until a mysterious attack destroyed an underwater section of this infrastructure. The consequences of the conflict on the European gas market have been devastating with a very serious impact on economic activities and the rate of inflation.

The price of gas at the Dutch HUB TTF after a phase of relative decline in the first two months of the year jumped in March to 223.3 $/b against the background of the intensification of fighting between Russia and Ukraine, exceeding the previous peak in December. After a new phase of descent, coinciding with the conclusion of the winter season overcome with the wide use of storage, prices began to rise dramatically coinciding with the start of the storage campaign for the winter season 2022-2023.

The jump in demand coincided precisely with the loss of increasing shares of Russian supplies via pipeline and in the initial phase of the efforts of all countries to build a new supply system less dependent on Russia.

At the Dutch HUB TTF, lacking the liquidity provided by Russia, and with limited alternatives, the prices inflated also by speculative and precautionary purchases, the quotations touched, on average, in August 344.7 $/b, an unbearable level for the European economy while discussions multiplied within the European Union on how to curb this escalation of prices up to the adoption of a "Price Cap" in case of exceeding a certain threshold.

Starting from September, the overall reactions aroused by the explosion in prices on the demand side, lower consumption due to the shutdown of many energy-intensive activities and rationalization interventions, above-average temperatures, and supply, with higher imports from other countries, began to affect the price dynamics at the FTT hub.

LNG has been the great protagonist of this change thanks to the first upgrading of receiving infrastructures in northern Europe and the full use of those located in Spain, Italy and France that will form the basis of a system that will have the Mediterranean as its center of gravity.

In other words, to achieve a stabilization of the market after a phase that will still be characterized by strong volatility that will affect the whole of 2023, it will be necessary that all the initiatives undertaken in this emergency period to create a new supply system based on LNG and a bigger role for the Mediterranean is implemented without delay.

In October, again on a monthly average, gas prices fell to $ 115.3 / b, a value still higher than that of crude oil but still explained by the complexity of the international situation. In November, prices were recorded on a daily basis even lower close to pre-pandemic levels but then prices returned above 100 $/ b.

On the other hand, even in the event of a truce or some form of solution to the conflict between Russia and Ukraine, the return to normality can only take place after the next winter season is overcome and after the full replenishment of stocks that will be put to the test this winter.

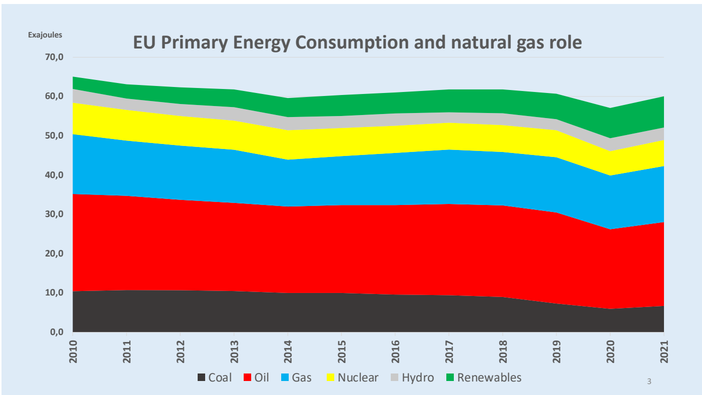
In this scenario, we can assume an international gas price less fragmented than in the past between the main geographical areas and determined by the demand and supply of LNG that has all the characteristics of a global market commodity, not subject to discriminatory practices by a single country or by cartels of producers, as occurred in the past with OPEC for oil.

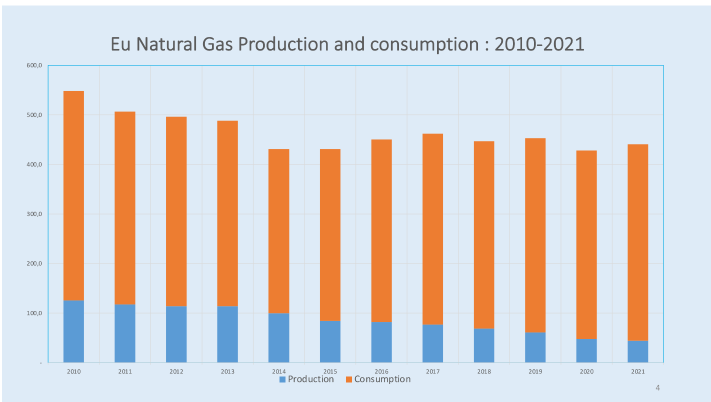
The LNG market already sees as the first producer’s countries with market economies and governed by democracies, such as the USA and Australia, as well as Norway and Canada, and which will be joined by new players in Africa and the Middle East with enormous potential.

With the expansion of the supply of which there are all the prerequisites, gas prices will return to levels much lower than the current ones, but which will still have to be sufficient to

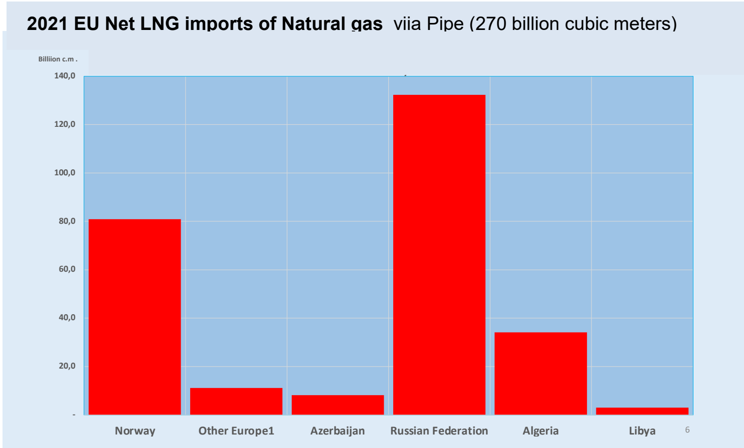
ensure its competitiveness vis-à-vis oil and renewables.

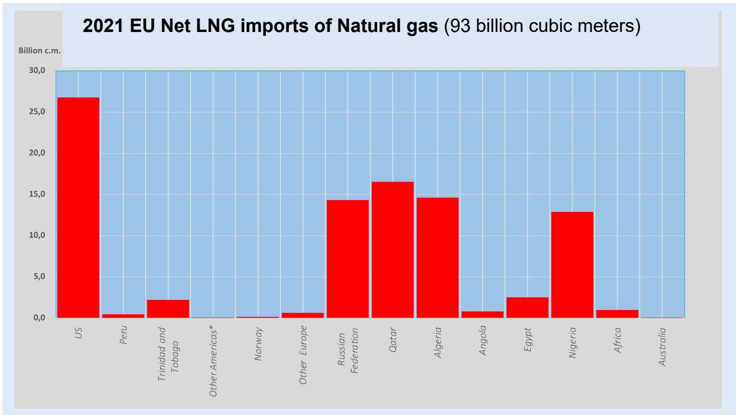
This could be around 40-50 $/b as also envisaged in the basic assumptions of the “World Energy Outlook” of the International Energy Agency published in October .





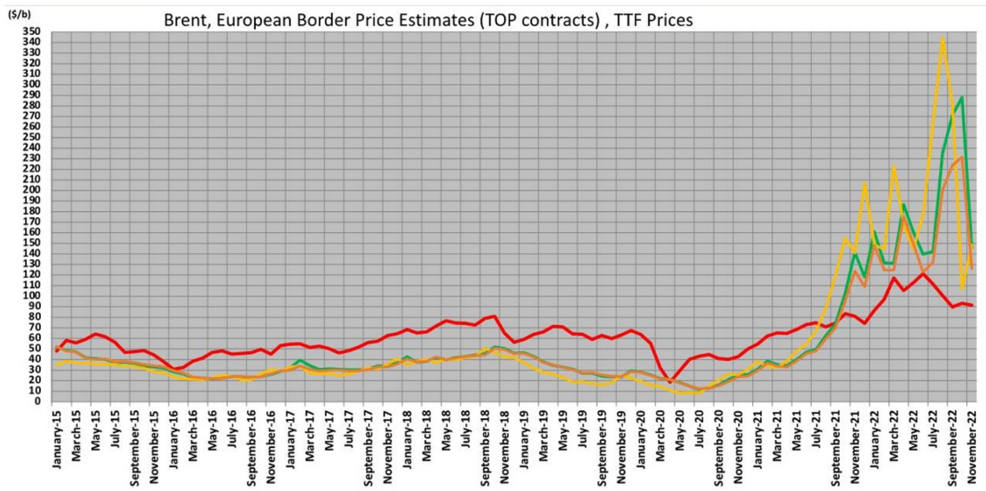
Source: elaborations on data from BP Statistical Review,2022





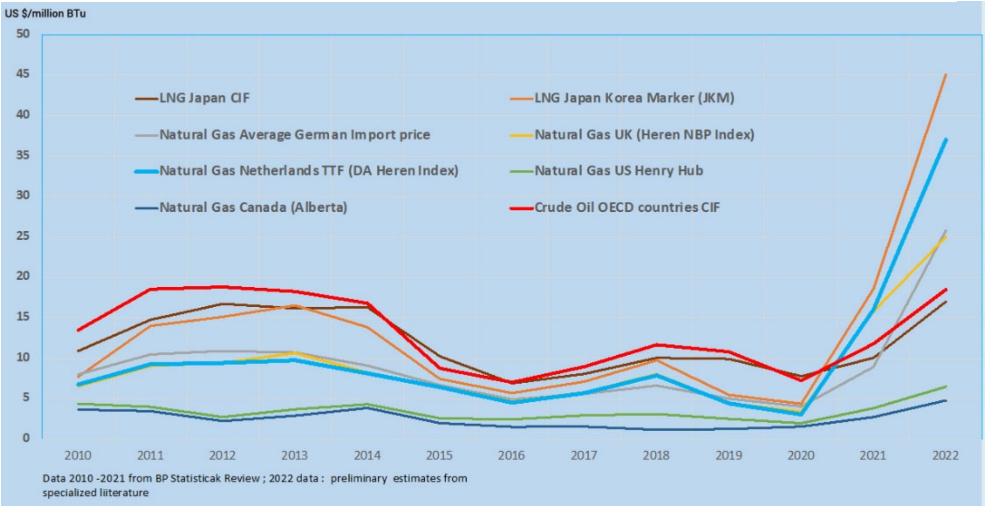
Source: elaborations on data from BP Statistical Review,2022

Oil annd gas prices in Europe :2015-2022

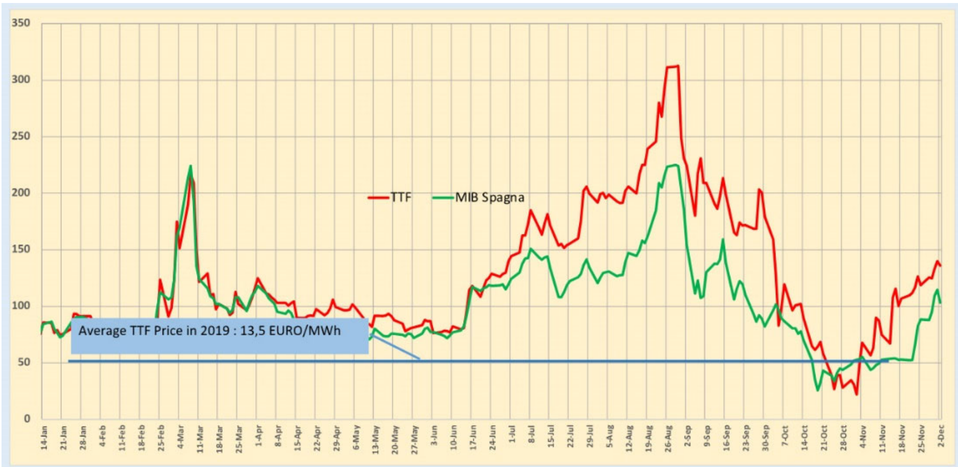


Source: elaborations on data from BP Statistical Review,2022 and specialized literature

International gas prices: the 2022 revolution



Daily prices at TTF and MIB in 2022
€/MWh



Source: elaborations on data from specialized literature

ELECTRICITY CONSUMPTION, FOREIGN DIRECT INVESTMENTS, CARBON DIOXIDE EMISSIONS AND ECONOMIC GROWTH IN UGANDA

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Abstract

Back ground: This paper investigates the causal relationship between electricity consumption, foreign direct investments (FDIs), carbon emissions and economic growth in the Uganda for the period 1990-2018.
Methods: It uses pooled mean group based autoregressive distributed lag (PMG- based ARDL) to deduce evidence of long run dynamic relationship between variables of study.
Results: Results indicate a long run relationship from electricity consumption to GDP. It is a significant positive relationship. Similarly, a positive relationship from CO2 to GDP. While a positive relationship from FDI and GDP exists both in the short and long run. Both labour and real gross fixed capital formation have a positive and statistically significant impact on the GDP in the short run while electricity consumption is statistically insignificant
Conclusion: Our findings indicate that regional governments must increase investment in electricity markets so as to boost greater benefits from regional cooperation
Originality /Value: This is the first paper according to our knowledge to study dynamic causal relationships between

Key words: Electricity consumption, Carbon dioxide emissions, Foreign Direct Investments, Economic growth, Uganda.

1. Introduction

1.1 Preamble

Electricity is a key driver of industrial operations, which in turn promotes economic growth (Mutumba 2021). Uganda's investment in electricity generation, transmission and distribution and consumption is dominated by foreign direct investments (FDIs) (Chingoiro and Mbulawa 2017). The debate is that Foreign Direct Investments (FDIs) stimulate economic growth (Tapera and Mawaza 2014), while other studies find no evidence to support this finding (Lipsey, 2002). Obwona (1998) and Odongo (2012) attempted to investigate the determinants and impacts of FDI inflows on the economic growth in Uganda. Although, Riddervold (2011), attempted to investigate effect of FDI inflows on Uganda's economy, it focused more on the role of FDI inflows on Uganda's employment other than economic growth.
Multinational corporations that invest in developing countries tend to use technologies that are not too strict on carbon emission standards, hence often perpetrating the carbon emission problem in these countries under the pollution haven hypothesis Balsalobre et al. (2019), Sinha et al., (2020).
No country study has been systematically carried out on electricity consumption, FDIs, carbon dioxide emission (CO2) and economic growth has been done for Uganda. This study seeks to fill this gap by devising appropriate methodology for analyzing electricity consumption, carbon emissions, FDI and economic growth, secondly is to use a multivariate framework for period and data set for analyzing the linkages between variables of study and avoid the omitted variables problem (Lütkepohl, 1999, Cheng 1996, Tang et al. 2016).

1.2 The Objectives

The general objective is to evaluate the dynamic relationship between electricity consumption, FDIs, CO_2 and GDP to form a basis for robust decision making, but more specifically to

(i) Investigate the direction of causality between electricity consumption and economic growth both in the short and long run in Uganda.
(ii) Investigate the direction of causality between FDIs and economic growth both in Uganda.

(iii) Investigate the direction of causality between CO2 emissions and economic growth both in Uganda.

1.3 The hypothesis

The main arguments that are important this debate is to explore the dynamic causal relationship between variables of study. The debate on the direction of causality between electricity consumption and economic growth has been categorized rhetorically into four hypotheses that lend themselves to independent verification namely: growth, conservation, feedback, and neutrality.

(i) Growth hypothesis contends that electricity consumption has a single direction causality running from electricity consumption to economic growth process. The growth hypothesis is valid if there is causality from electricity consumption to economic growth (Bilgili 2015, Ozturk and Bilgili 2015, Bozkurt and Destek 2015, Hamit-Haggar 2016, Alper and Oguz 2016, Inglesi-Lotz 2016, Destek and Aslan 2017, Kahia et al., 2017, Zallé, 2018, Mbarek et al., 2018). Under the growth hypothesis, electricity conservation policies that reduce electricity consumption may have an adverse impact on economic growth.

(ii) Conservation hypothesis postulates that strategies designed to lower electricity consumption and waste may not have an adverse impact on economic growth. The conservation hypothesis is confirmed if there is unidirectional causality from economic growth to electricity consumption.

(iii) Feedback hypothesis emphasizes mutual relationship between electricity consumption and economic growth and their complementarity(Cheng 1999 , Hondroyiannis et al. 2002, Narayad & Prasad 2008, Adeyemi & Ayomide 2013, Hamdi et al., 2014, Mawejje and Mawejje 20016, Senkatsi & Okot 2016, Mukhtarov et al 2017, Salauddin & Gow 2019, Kahia et al., 2019, Akadiri et al., 2019), Others that used panel data studies with same results include (Soytas & Saris 2003, 2006, Lee 2006, Zachariadis 2007, Constantini & Martini 2010, Belke et al., 2011, Yildrim & Aslan 2012, Fuinhas & Marques 2012, Jammazi & Aloui 2015, Osman 2016, Bildric et al., 2016). The presence of two-way causality between electricity consumption and economic growth lends itself to feedback mechanism.

(iv) Finally, the neutrality hypothesis considers electricity consumption to be a small component of an economy's overall output and thus may have little or no impact on economic growth. Similar to the conservation hypothesis, electricity conservation policies may not have an adverse impact on economic growth under the neutrality hypothesis. The neutrality hypothesis is confirmed by no causal relationship between electricity consumption and economic growth (Apergis and Payne 2010). The hypotheses for this transmission mechanism is given as:

H0: Electricity consumption has no causal relationship on GDP growth.
H1: Electricity consumption has a causal relationship on GDP growth

Table 1: Hypothesis Testing

1.Electricity consumption has no causal relationship on GDP in Uganda 2. Electricity consumption has a causal relationship on GDP in Uganda	$H_0 : \beta = 0$ $H_1 : \beta \neq 0$
3.FDIs have no causal relationship on energy consumption in Uganda 4. FDI have a causal relationship on energy consumption in Uganda	$H_0 : \beta = 0$ $H_1 : \beta \neq 0$
5. CO_2 emissions have no causal relationship on energy consumption in Uganda 6. CO_2 have a causal relationship on energy consumption in Uganda	$H_0 : \beta = 0$ $H_1 : \beta \neq 0$

1.4 The contribution of this paper

The main contribution of this study to energy economics literature will be to apply a multivariate analysis to a standard economic growth model, which will reduce the omitted variables problem (Lütkepohl 1982). Electricity is complementary to labour and capital as inputs used in the production process and will be used as controls in this model (Sekantsi and Motlokoa 2015).
Secondly, it will analyse the direction of causality on electricity consumption, FDIs, carbon emissions as major drivers of economic growth in Uganda. This study will investigate the direction of causality using auto regression distributed lag (ARDL) and bounds cointegration test will be carried out and

granger causality test. The contribution electricity consumption makes on economic growth to the Ugandan economy is not clearly known. This study seeks to fill this gap.

Thirdly, based on the current literature, this study will use time series econometrics with many observations which will increase the power and size effects of the unit root and cointegration techniques. More specifically the ARDL will be used to provide a suitable and valid basis for policy making.

Finally, it will examine the significance of energy policy framework in promoting all- inclusive growth. This will provide useful insights to both social planners and economic planners on the proper energy options that are friendly to the environment and yet will yield inclusive growth.

1.5 The Roadmap

The remaining part of this paper discusses section 2 as empirical literature, in section 3 is methods, section 4 is findings and discussion, section 5 is conclusions and recommendations.

2. Empirical Literature

There is an increasing body of knowledge in support electricity consumption and economic growth (de Janosi and Grayson 1972, Carter 1974, Kraft and Kraft 1978), while environmental quality and economic growth was pioneered by (Grossman and Krueger 1991) additional studies involving FDIs and economic growth include (Cole 2004, Copeland and Taylor 1994, 2004 and Waldikirch & Gopinath 2008) .The resultant findings are controversial (Mutumba et al, 2021). Where significant results were obtained they indicate that linkages between electricity consumption, CO2 emissions, FDIs and economic growth. A more systematic treatise of the relevant variables is analysed in the binary nexus as below.

2.1 **Literature on electricity consumption and economic growth**

Bekun and Agbola (2019) used data for Nigeria between 1971- 2014 using both a dynamic modified and fully modified ordinary least squares (DMOL & FMOL), Maki cointegration, Toda-Yamamota, Mwald tests, he found a dynamic relationship from electricity consumption to GDP, while Ogundipe and Oyomide (2013) used data of 1980 to 2008 used VECM, Johansen and Juselius cointegration and a Cobb Douglas(CD) production function found a bidirectional hypothesis Ogundipe (2016), Bah and Azam (2017), studied energy consumption and economic growth in South Africa using data of 1971-2012, used an ARDL and CD production function found no causality, Weng and Cheng Lu (2017) studied the economy of Taiwan using data of 1984 to 2014 using granger causality found a bidirectional relationship. Ibrahiem (2018) studied Egypt using VECM and a Johansen test, he found a relationship running from Electricity consumption to GDP.

Muhammad and Nur- Syazwari (2018), looked at electricity consumption and economic growth of Malaysia using ARDL found a relationship running from electricity consumption to GDP. Mukhtarov et al (2018) studied electricity consumption and economic growth of Azerbaijan using data of 1992-2015, he used VECM and Johansen test and found a unidirectional relationship running from electricity consumption to GDP, while study of Humbatov (2020) who used data of Azerbaijan of 1995 to 2017 using ARDL, augmented Dickey fuller (ADF), Phillips Peron (PP) and pairwise granger causality test found no relationship between the variables. Ozturk et al (2019) investigated Denmark using data of 1970- 2012, he used ARDL and granger causality test and found no relationship between electricity and GDP. Nepal and Paija(2019) studied Nepal using data of 1975- 2014, they ARDL, Toda Yamamoto and Granger causality test they found no relationship, earlier Bastola and Sapkota (2015) had studied the same and found a single directional relationship running from electricity to economic growth. Akadiri et al (2019) studied Turkey using ARDL, Toda Yamamoto and Granger causality test, they used Environmental Kuznet Curve (EKC) and Long range Energy Alternative Program (LEAP) they found a bidirectional relationship. Salahuddin and Gow (2019) studied Quatar using ARDL, Toda Yamamoto, they used Environmental Kuznet Curve (EKC) and data of 1980 – 2016, and they found a bidirectional relationship.

Zhang et al., (2020) studied electricity consumption and economic growth in Pakistan using data of 1960 -2014, they used a VECM and Average Neural Network (ANN) method and found a unidirectional relationship running form electricity consumption to economic growth, which is in agreement with earlier work of Agee and Butt (2015). Ridzual et al., (2020) studied electricity consumption and economic growth of Malaysia using data of 1970 to 2016 adopted a multivariate framework using the ARDL and cumulative sum of squares, he adopted the Solow growth model. Lin and Zu (2020) studied China and found a relationship running from GDP to Electricity, while Junsheg et al (2018) using Toda Yamamoto and Granger found the relationship running from electricity consumption to economic growth.

Many scholars have argued that causality runs form electricity consumption toGDP (Tang et al. 2016, Molem and Ndifor, 2016, Zalle 2019, Akadiri et al., 2019, Latief and Lefien 2019, Bekun and Agbola 2019, Adjarwati et al., 2020, Ahmad et al., 2020, Chen et al 2020 Parveen et al., 2020, Kirikkalelli et al., 2020, Tran et a., 2020, Anser et al., 2021 Bashir et al., 2021). Other scholars argue that causality runs from growth to electricity consumption (Gorus and Aydin 2019, Umurzakov et al, 2020, Shojaee and Seyedin 2021). While neutral hypothesis has been postulated by scholars like (Nguyen and Ngochi 2019)

2.2 Literature on Electricity Consumption, Carbon dioxide emissions and economic growth

Some studies indicate increased carbon emissions lead to economic growth (Managi 2006, Cavilia-Harris et al., 2009, Kaika and Zervas 2013) while others are on the contrary (Grossman and Krueger 1991, 1995, Balsalobore 2015, Mazur et al., 2015, Giovanos 2012) argue that higher carbon emissions do not lead to increased GDP.

3. Methods

3.1 Data source

Yearly data of Uganda's economic growth (GDP), electricity consumption (ELC), labour force (LF) and capital formation (GCF) from1990 to 2018 was got from World Bank Development indicators.

Table 1: Variables and expected signs

Variables	Symbol	Measure	Expected Sign	Data source
Gross Domestic Product	GDP_t	GDP constant 2010 US$	+	World Bank: World development indicators(WDI)
Gross capital formation	GCF_t	GDP constant 2010 US$	+	World Bank: World development indicators (WDI)
Gross labour force	LBR_t	Labour	+	World Bank: World development indicators (WDI).
Carbon dioxide emission	$CO2_t$	Million tons of emission	+	World Bank: World development indicators (WDI).
Foreign Direct Investments	FDI_t	Ratio of GDP	+	World Bank: World development indicators(WDI)
Electricity Consumption	ELC_t	GWh	+	International Energy Agency (IEA)

The variables selected shown in table 1 included; Gross domestic Product, Gross Capital formation both at a constant. US$ 2010, Labour force, Electricity consumption and FDI.

3.2 The Theoretical framework -Neoclassical growth Model

This study used a neoclassical growth theory by Solow (1956, 1987). The Solow growth theory to analyse the relationship between electricity consumption and economic growth. Unlike the Solow-neutral model which augments capital as an input, this study will provide electricity as a separate input into the production model; and investigates its relationship with growth. Output (Y), Labour force (L), Capital (C), and Electricity consumption a component of renewable energy, that is Electricity (E) will be measured

Thus the model will be specified as:

$$Y_t = f(E_t, FDI_t, CO2_t, K_t, L_t) \qquad (1)$$

$$Y_t = \alpha + \delta_t + \beta_1 E_t + \beta_2 FDI_t + \beta_3\, CO2_t + \beta_4 K_t + \beta_5 L_t + u_t \qquad (2)$$

Where: Y_t is output/ real Gross GDP

The parameters α and δ allow for the possibility -specific fixed effects and deterministic trend respectively, E_t is Electricity Consumption, FDI is Foreign Direct Investment, CO_2 is Carbon emission, K_t is Capital formation, L_t is Labour force and u_t is the error term.
The choice of the Solow model production is essentially because of the suitability as a production function in explaining economic growth. The Solow neutral model augments capital with technological progress and as such this model brings domestic electricity demand as a variable of study. Economic growth as a matrix of goods and services that an economy can produce is best represented by a production function. The basic inputs are capital, labour and the composite energy good, Electricity. Capital formation and electricity consumption are studied in the same model because capital is treated as a stock and electricity consumption is a flow of resources.

3.3 The Econometric Model: Vector Error Correction Model

Economic growth (Y) is modelled as a function of electricity function (E), capital (c), labour (L); which can then be transformed and rewritten by specifying an error-correction representative inclusive vector autoregressive model as follows;

$$(1-\delta)\begin{bmatrix} Log\,Y_t \\ Log\,E_t \end{bmatrix} = \begin{pmatrix} \alpha_1 & \gamma 1 \\ \alpha_2 & \gamma 2 \end{pmatrix}\begin{pmatrix} I \\ X_{t-i} \end{pmatrix} + \sum_{i=1}^{p}(1-\delta)\begin{bmatrix} \beta 11 & \beta 12 & \beta 13 \\ \beta 21 & \beta 22 & \beta 23 \end{bmatrix}\begin{bmatrix} logE \\ logK \\ logL \end{bmatrix} + \begin{pmatrix} V_{1t} \\ V_{2t} \end{pmatrix} \ldots.(3)$$

Note that all the variables are expressed in logs.

X = the Error-Correction Model (ECM), which is the lagged value of the error term from the following cointegration equation below:

$$Y=\alpha_0+\gamma E_t+\alpha_1 K_t+\beta L_t+e_t \ldots\ldots (4)$$

$$(1-\delta)Y_t = \alpha_0+X_{t-1}+Y_{t-1}+V_{1t} \ldots\ldots (5)$$

$$(1-\delta)Y_t=\alpha_0 + X_{t-1} +\sum_{i=1}^{m}(1-\delta)Y_{t-1}+E_{t-j} + V_{1t} \ldots\ldots (6)$$

$$(1\text{-}\delta)Y_t=\alpha_0+X_{t-1}+\sum_{i=1}^{m}(1-\delta)Y_{t-1}+\sum_{j=1}^{n}(1-\delta)E_{t-j}+ V_{3t} \ldots\ldots (7)$$

$$(1\text{-}\delta)Y_t=\alpha_0+X_{t-1}+\sum_{i=1}^{m}(1-\delta)Y_{t-1}+\sum_{j=1}^{n}(1-\delta)E_{t-j}+\sum_{p=1}^{p}(1-\delta)E_{t-p}+V_{3t} \ldots\ldots (8)$$

$$\Delta Y_t=\omega_1+\sum_{k=1}^{q}\theta_{11k}\Delta Y_{t-k}+\sum_{k}^{q}\theta_{12k}\Delta E_{t-k}+\sum_{k}^{q}\theta_{13k}\Delta K_{t-k}+\sum_{k}^{q}\theta_{14k}\Delta L_{t-k}+\lambda_1\varepsilon_{t-1}+u_{1t} \ldots\ldots (9a)$$

$$\Delta E_t=\omega 2+\sum_{k=1}^{q}\theta_{21k}\Delta Y_{t-k}+\sum_{k=1}^{q}\theta_{22}k\Delta E_{t-k}+\sum_{k}^{q}\theta_{23k}\Delta K_{t-k}+\sum_{k}^{q}\theta_{24k}\Delta L_{t-k}+\lambda_2\varepsilon_{t-1}+u_{2t} \ldots\ldots (9b)$$

$$\Delta K_t=\omega 3+\sum_{k=1}^{q}\theta_{31k}\Delta Y_{t-k}+\sum_{k=1}^{q}\theta_{32}k\theta_{22k}\Delta E_{t-k}+\sum_{k}^{q}\theta_{33k}\Delta K_{t-k}+\sum_{k}^{q}\theta_{34k}\Delta L_{t-k}+\lambda_2\varepsilon_{t-1}+u_{3t} \ldots (9c)$$

$$\Delta L_t=\omega 4+\sum_{k=1}^{q}\theta_{41k}\Delta Y_{t-k}+\sum_{k=1}^{q}\theta_{42}k\Delta E_{t-k}+\sum_{k}^{q}\theta_{43k}\Delta K_{t-k}+\sum_{k}^{q}\theta_{44k}\Delta L_{t-k}+\lambda_4\varepsilon_{t-1}+u_{4t} \ldots\ldots (9d)$$

where Δ is the first-difference operator,
q is the lag length set at one based on likelihood ratio tests,
and u is the serially uncorrelated error term.

Given Eqs. (9a)–(9d), short-run causality is determined by the statistical significance of the partial F-statistics associated with the corresponding right hand side variables. The null hypothesis of no long-run causality in each equation. Equations. (9a)– (9d), is tested by the statistical significance of the t-statistics for the coefficient on the respective error correction terms represented by λ. In terms of Equation (9b), both economic growth and real gross fixed capital formation each have a positive and statistically significant impact on renewable energy consumption in the short-run whereas the labour force has a statistically insignificant impact. For Equation (9c), economic growth, renewable energy consumption, and the labour force each have a positive and statistically significant impact on real gross fixed capital formation. Moreover, both renewable energy consumption and the labour force appear to serve as complements to real gross fixed capital formation. With respect to Eq. (9d), at the 95% confidence interval,

3.4 Diagnostic tests

This subsection mainly looks at post estimation tests particularly the test from stationarity and unit root, serial correlation, functional form, co-integration, heteroscedasticity and normality as explained.

3.4.1 Stationarity and Unit Root

To test for unit roots in our variables, we use the Augmented Dickey Fuller (ADF) test. Using the results of Dickey and Fuller (1979), the null hypothesis that the variable shows that all variables have unit roots.

3.4.2 Test for Serial Correlation

We used the Breusch-Godfrey LM test because (Damodar, 2004) to test for serial correlations. The null hypothesis (Ho) is that there is no serial correlation of any order. If the sample size is large enough, Breusch and Godfrey have shown that:

$(n-p)R^2 \sim X_p^2$……………………………………………………………………………… (10)

Implying that asymptotically, n-p times the R^2 follows the chi-square distribution with PDF. If in an application, (n-p) R^2 exceeds the critical chi-square value at a chosen level of significance, we reject the null hypothesis. Thus, the null hypothesis is rejected if p-value is less than 5%, in our case it is 0.00 so we reject the null hypothesis.

3.4.3 Determining the appropriate Lag Length for VECM model

The need for the lags arises because values in the past affect today's values for a given variable. This is to say the variable in question is persistent. There are various methods to determine how many lags to use. The AIC was used to determine the appropriate lag length given the large sample size of 37 observations.

3.4.4 Co-integration test

This test is used to check if there exists a long-run relationship between the study variables. Generally, a set of variables is said to be co-integrated if a linear combination of the individual series, which are I(d), is stationary. Intuitively, if xt ~ I(d) and yt ~ I(d), a regression is run, If the residuals, εt, are I(0), then Et and yt are co-integrated. We use Johansen's (1988) approach, which allows us to estimate and test for the presence of multiple co-integration relationships. The choice of lag length is made according to the AIC criterion. In conclusion there is one co-integration rank (long-run relationship). When determining lag structures of the data-generating processes (DGP), we use the Johansen (1988) procedure to test the existence of long-run equilibrium relations using the trace statistic test for co-integration, because our data are based on rather small samples, the estimation procedure that we adopt accounts for the Bartlett correction following Johansen (2000). The Johansen co-integration procedure does not reject the null hypothesis of one co-integrating equation. The Johansen trace and max test statistics suggest the existence of at least 1 co-integrating relationship between GDP and electricity consumption. Hence, we estimated the Vector Error Correction Model (VECM) analysis. Why the VECM? According to Henry and Mizon (1978), this choice of the econometric model is because of existence of a co-integration problem. Since the error structure in nonstationary in levels, the problem is estimated in a first difference formulation. The Dickey Fuller test is used to determine whether the remainder is stationary Dickey Fuller, and the Augmented Dickey Fuller test is applied on the least square residual to implement the Engel and Granger procedure.

3.4.5 Test for functional form

We may have a model that is correctly specified, in terms of including the appropriate explanatory variables, yet commit functional form misspecification. In this case, the model does not properly account for the form of the relationship between dependent and observed explanatory variables. In this study, a general test for functional form misspecification is Ramsey's RESET (regression specification error test) which was applied.

3.4.6 Test for heteroscedasticity

The error term is found to homoscedastic using the Breush Pagan test this shows the stability of the parameters using residual diagnostics to minimize errors (or residuals). The error term is be independently and identically distributed (i.i.d). Using the correlogram, the error term of the estimated model. This procedure of log transformation is important because it stabilises the means, however the means are also found to be non-stationary.

3.4.7 Test for normality

The Jacque Bera normality test was used to test for normality, which variable is relevant to express as linear combination among other variables, Using the Maximum Likelihood- Auto Regressive Conditional Heteroscedasticity (ML ARCH) the residuals were normally distributed as shown in appendix 3 (table 5).

3.4.8 Granger Causality

According to the Granger's (1969) approach, a variable Y is caused by a variable E if Y can be predicted better from past values of both Y and E than from past values of Y alone. For a simple bivariate model, we can test if E is Granger-causing Y by estimating Eq. (11) and then test the null hypothesis in Eq. (12) by using the standard Wald test.

$Y_t = \mu + \sum_{j-1}^{n} \gamma Y_{t-j} + \sum_{j-1}^{n} \alpha_1 1E_{t-j} + \mu_t$……………………………………………………………(11)

$H_0 : \gamma = 0$ for $j = 1,...,n$

$H_1 : \alpha \neq 0$ for at least one j…………………………………………………………………(12)

Where μ is a constant and u_t is a white noise process.

4. Findings and Discussion

4.1 Findings

4.1.1 Stationarity

Findings of stationarity test using the ADF, indicate that electricity consumption (ELC) is non-stationary (the null hypothesis is rejected) at levels while it becomes stationary at first difference. FDI and CO2 also become stationary at first difference.

Log of GDP at level I(0) non stationary

Augmented Dickey-Fuller test for unit root Number of obs = 35

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	0.573	-3.682	-2.972	-2.618

MacKinnon approximate p-value for Z(t) = 0.9869

Log of GDP at level I(1) stationary

Augmented Dickey-Fuller test for unit root Number of obs = 31

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-3.214	-3.709	-2.983	-2.623

MacKinnon approximate p-value for Z(t) = 0.0192

Log of electricity consumption
Non stationary at level I(0)

Augmented Dickey-Fuller test for unit root Number of obs = 35

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-0.534	-3.682	-2.972	-2.618

MacKinnon approximate p-value for Z(t) = 0.8851

Log of electricity consumption
Stationary at level I(1)

Augmented Dickey-Fuller test for unit root Number of obs = 34

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-5.943	-3.689	-2.975	-2.619

MacKinnon approximate p-value for Z(t) = 0.0000

Log of CO2 emissions
Not stationary at level, I(0)

Augmented Dickey-Fuller test for unit root Number of obs = 35

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	0.696	-3.682	-2.972	-2.618

MacKinnon approximate p-value for Z(t) = 0.9898

Log of CO2 emissions
Stationary at level, I(1)

Augmented Dickey-Fuller test for unit root Number of obs = 34

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-4.154	-3.689	-2.975	-2.619

MacKinnon approximate p-value for Z(t) = 0.0008

Log of FDI
Not stationary at level, I(0)

Augmented Dickey-Fuller test for unit root   Number of obs = 35

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	0.696	-3.682	-2.972	-2.618

MacKinnon approximate p-value for Z(t) = 0.9898

Log of FDI
Stationary at level, I(1)

Augmented Dickey-Fuller test for unit root   Number of obs = 34

	Test Statistic	Interpolated Dickey-Fuller 1% Critical Value	5% Critical Value	10% Critical Value
Z(t)	-4.154	-3.689	-2.975	-2.619

MacKinnon approximate p-value for Z(t) = 0.0008

Note
All variables are integrated of order 1, I(1)

4.1.2 Serial Correlation
Findings from the serial Correlation test indicate no serial correlation

Lagrange-multiplier test

lag	chi2	df	Prob > chi2
1	17.3398	16	0.36394

H0: no autocorrelation at lag order

Note: No serial correlation present.

4.1.3 Optimal Lag Length

Using the SBIC information criteria the appropriate lag length is 2.

lag	LL	LR	df	p	FPE	AIC	HQIC	SBIC
0	-7.32568				.000023	.686405	.747439	.8678
1	155.387	325.42	16	0.000	3.2e-09	-8.20525	-7.90008	-7.29828*
2	174.213	37.652	16	0.002	2.9e-09	-8.37653	-7.82722	-6.74397
3	191.985	35.545	16	0.003	2.9e-09	-8.48395	-7.69051	-6.12581
4	215.861	47.753*	16	0.000	2.3e-09*	-8.9613*	-7.92373*	-5.87759

4.1.4 Cointegration

The long run Johansen cointegration results indicate the presence of aleast onecointegrating equation, therefore a long run relationship existing among the variables.

Johansen tests for cointegration

Trend: constant — Number of obs = 36

Sample: 1983 - 2018 — Lags = 1

maximum rank	parms	LL	eigenvalue	trace statistic	5% critical value
0	5	185.04678	.	70.5427	68.52
1	14	201.83042	0.60640	36.9754*	47.21
2	21	211.52158	0.41632	17.5931	29.68
3	26	217.11292	0.26702	6.4104	15.41
4	29	220.31305	0.16288	0.0102	3.76
5	30	220.31813	0.00028		

maximum rank	parms	LL	eigenvalue	max statistic	5% critical value
0	5	185.04678	.	33.5673	33.46
1	14	201.83042	0.60640	19.3823	27.07
2	21	211.52158	0.41632	11.1827	20.97
3	26	217.11292	0.26702	6.4003	14.07
4	29	220.31305	0.16288	0.0102	3.76
5	30	220.31813	0.00028		

4.1.5 Normality

The JB test indicate that data is normally distributed

Jarque-Bera test

Equation	chi2	df	Prob > chi2
D_LGDP	0.057	2	0.97197
D_LELEC	5.542	2	0.06259
D_LCO2	0.013	2	0.99371
D_LFDI	18.292	2	0.00011
ALL	23.904	8	0.00238

4.1.6 Granger

Granger causality test indicate a causal relationship running from electricity consumption to GDP. FDI also Granger causes GDP and CO2 granger causes economic growth.

4.1.7 VECM Results

Vector error-correction model

Sample: 1983 - 2018

		Number of obs	= 36
		AIC	= -7.851103
Log likelihood =	152.3199	HQIC	= -7.682226
Det(Sigma_ml) =	2.48e-09	SBIC	= -7.36725

Equation	Parms	RMSE	R-sq	chi2	P>chi2
D_LGDP	2	.023398	0.8678	223.2761	0.0000
D_LELEC	2	.160134	0.1943	8.201157	0.0166
D_LCO2	2	.081632	0.4176	24.37645	0.0000
D_LFDI	2	.228771	0.0320	1.12557	0.5696

	Coef.	Std. Err.	z	P>|z|	[95% Conf. Interval]	
D_LGDP						
_ce1						
L1.	-.1877063	.0439672	-4.27	0.000	-.2738805	-.1015321
_cons	.0740243	.0057746	12.82	0.000	.0627062	.0853424
D_LELEC						
_ce1						
L1.	.4039948	.3009067	1.34	0.179	-.1857714	.993761
_cons	.028377	.039521	0.72	0.473	-.0490828	.1058367
D_LCO2						
_ce1						
L1.	-.0166584	.1533937	-0.11	0.914	-.3173046	.2839878
_cons	.06877	.0201467	3.41	0.001	.0292832	.1082568
D_LFDI						
_ce1						
L1.	.1728718	.4298831	0.40	0.688	-.6696835	1.015427
_cons	.0206874	.0564607	0.37	0.714	-.0899735	.1313484

Cointegrating equations

Equation	Parms	chi2	P>chi2
_ce1	3	1679.496	0.0000

Identification: beta is exactly identified

Johansen normalization restriction imposed

beta	Coef.	Std. Err.	z	P>|z|	[95% Conf. Interval]	
_ce1						
LGDP	1	.	.	.	.	.
LELEC	-.2899569	.0724725	-4.00	0.000	-.4320004	-.1479133
LCO2	-.4722221	.0628192	-7.52	0.000	-.5953454	-.3490987
LFDI	-.2582772	.0365793	-7.06	0.000	-.3299712	-.1865832
_cons	-13.42283	.	.	.	.	.

From the VECM results an increase of Electricity consumption leads to an increase in GDP. Similarly, carbon dioxide emissions and FDI also increase in GDP.

4.2 GDP and Electricity consumption

4.2.1 Lag Length selection

Since it has been shown that ADF tests are sensitive to lag lengths (Campbell & Perron, 1991) we determine the optimal lag length by using Akaike's information criterion (AIC).The formal testing of the lag structure is based on the maximum likelihood function. From the information in appendix 2 (Table1) we see that previous GDP affects current GDP, such that a 1% change in current GDP is explained by a 6% of previous GDP.

4.2.2 Co-integration test

The Johansen trace and max test statistics suggest the existence of atleast 1 co-integrating relationship between GDP (LGDP) and Electricity consumption (Lelec), So we reject the null hypothesis at the 5% level of significance, thus we go ahead to determine the long run relationship using VECM results show that a positive and significant relationship exists between Electricity consumption and GDP. Specifically a 1% increase in Electricity consumption tends to increase GDP by tends 0.06% as shown in appendix 4 (table 2).

4.2.3 Empirical results

The empirical results from the multivariate framework shows appositive relationship running from Electricity consumption to GDP. This therefore supports the growth hypothesis. Results indicate a long run relationship from electricity consumption to GDP. It is a significant positive relationship.

Similarly, a positive relationship from CO_2 to GDP. While a positive relationship from FDI and GDP exists both in the short and long run. Both labour and real gross fixed capital formation have a positive and statistically significant impact on the GDP in the short run while electricity consumption is statistically insignificant.

The results indicate that there is a long-run equilibrium relationship between real GDP and electricity consumption, real gross fixed capital formation, and the labour force. Coefficients for real fixed gross capital, and labour force are positive and statistically significant at the 5% significance level, and given the variables are expressed in natural logarithms, the coefficients can be interpreted as elasticity estimates

5. Conclusions and Recommendations

5.1 Conclusions

The paper investigates the causal relationship between electricity consumption, FDI, CO_2 and economic growth for Uganda over the period 1990 to 2018, It used the Vector error correction mechanism and the granger causality to establish the dynamic causal relationship between the variables of interest. it is worthwhile to examine electricity consumption FDI and CO_2 emissions on Economic growth. Uganda has performed well in increasing hydroelectric power supply in the last decade with the hope to drive the economy at a much faster rate. There is need to guide further investments with rational and sound policy backed by evidence based research.

There is a growth hypothesis shown by a unidirectional causal relationship running from electricity consumption to economic growth. This implies that increasing electricity consumption increases economic growth and not the reverse. The absence of backward loop therefore, explains the critical increase in Electricity supply capacity that will spur an increase in electricity consumption in Uganda which will drive economic growth.

Similarly, a positive relationship from CO_2 to GDP. This is indicative that an increase in carbon dioxide emissions due to increased production in the industrial and commercial sector will translate into increased GDP. While a Bidirectional causal relationship exists between FDI and GDP. The positive relationship from FDI and GDP exists both in the short and long run. This means policies aimed at increasing should be encouraged to promote economic growth.

Both labour and real gross fixed capital formation have a positive and statistically significant impact on the GDP in the short run. These also support a bidirectional causal relationship therefore equal attention to investment in both human and physical capital to promote balanced growth.

5.2 Recommendations

In this paper, we investigated the causal relationship between electricity demand and economic growth for Uganda and base on the findings to make the following recommendations for both energy economists and policy authorities.

Policy makers should encourage a multilateral effort to promote Electricity consumption and information across countries with respect to on-going projects, technologies, as well as financing and investment strategies. The establishment of partnerships between the public and private sector would also facilitate the technology transfer process of bring renewable energy projects to market.

In addition, policy makers must introduce the appropriate incentive mechanisms for the development and market accessibility of renewable energy. Such incentives could include tax credits and/or subsidies for the production and consumption of renewable energy. The establishment of markets for tradable renewable energy certificates along with the implementation of renewable energy portfolio standards may promote the expansion of the electricity subsector in specific and the renewable sector in general.

Therefore, this paper recommends Ugandan authorities not only to develop energy policies geared towards expanding electricity infrastructure to increase electricity consumption only, but also address efficient energy use to support economic growth

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