Reinforcing Ukraine

How do different PV-deployment strategies reinforce energy security in Ukraine, while also help comply with GHG emission targets?

MSc SET thesis Project

H.J.H.M van Brandenburg

Reinforcing Ukraine

How do different PV-deployment strategies reinforce energy security in Ukraine, while also help comply with GHG emission targets?

by

H.J.H.M van Brandenburg

to obtain the degree of Master of Science
at the Delft University of Technology,

Student number:	4910648	
Project duration:	October , 2022 – May, 2023	
Thesis committee:	Dr. P. Manganiello,	TU Delft, supervisor
	Dr. S. Pfenninger,	TU Delft, supervisor
	PhD. F. Sanvito,	TU Delft, daily supervisor

An electronic version of this thesis is available at http://repository.tudelft.nl/.
The image on the front page is created using Dall-E

TU Delft

Preface

Writing this thesis has been a transformative experience, shaped by the invaluable guidance and support of remarkable individuals who have been instrumental in my academic and personal growth. I would like to express my heartfelt gratitude to my advisors Francesco Sanvito, Stefan Pfenninger and Patrizio Manganiello, my friends Alex, Niels, Maarten, and Guus, and my girlfriend Simone. Their unwavering belief in my abilities, encouragement, and intellectual contributions have played a crucial role in shaping this work. Their support has been a constant source of inspiration, and I am deeply grateful for their mentorship, friendship, and love.

Sincerely,
H.J.H.M van Brandenburg
Delft, May 2023

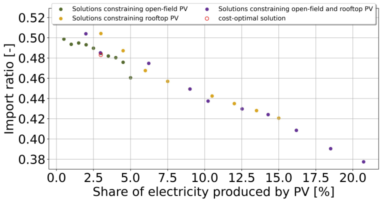
Summary

Ukraine is currently facing large energy security risks caused by its conflict with Russia. Recent events showed that the Ukrainian electricity and heat sector can be disrupted by Russian strikes. Besides energy security concerns, Ukraine is also not meeting its emission targets. Introducing renewable energy sources could increase energy security in Ukraine and help comply Ukraine with GHG emission targets. Therefore this thesis assesses how rooftop, open-field and the combined PV deployment strategy reinforce energy security and help comply with GHG emission targets.

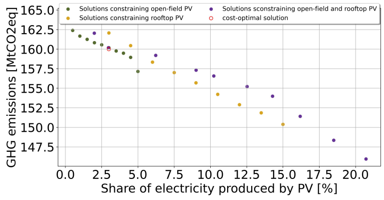
The research question is answered in two steps. First, a literature review is done on three topics, energy security, the current status of the Ukrainian heat and electricity systems and the potential and yields of renewable energy sources (RES) in Ukraine. The review on energy security resulted in three key performance indicators (KPIs) which can be used to evaluate energy security in Ukraine, import dependency, diversity (HHI) and greenhouse gas (GHG) emissions.
Analysis on the state of the Ukrainian heat and electricity sectors revealed that Ukraine is currently very dependent on fossil fuels, which negatively impacts the import dependence and GHG emissions. The analysis also showed that the sectors contain only a limited amount of renewable assets.
The literature study on the potential and yields of RES showed that these are available in large quantities. Geospatial analysis done in this research estimated 79 GW of rooftop PV and 9.7 GW of open-field PV potentials. It also estimated 440 GW of onshore wind and 140 GW of offshore wind potentials. Lastly, the study revealed a large availability of sustainable biomass in Ukraine, but this is currently not accessible since no infrastructure exists to collect, process and redistribute the biomass in Ukraine.

The second step was using these insights, to model Ukraine's heat and electricity sector using the Calliope optimization framework. Calliope computes optimal and sub-optimal configurations, to match the 2030 electricity and heat supply and demand. The model is used to conduct two simulations. The first simulation explores the effects of the deployment strategies if they are being maximized. The second simulation explores the effects caused by smaller amounts of PV in the heat and electricity sector. Based on the two simulations the impact of the different PV deployment strategies on the KPIs is assessed.

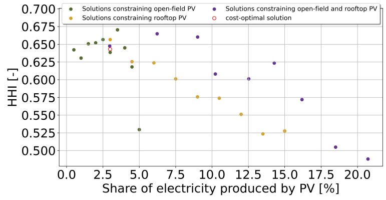
The results from the simulations indicate that the strategies equally affect the import dependency. However, the combined strategy is the most cost-efficient option for reaching lower import ratios. The results also showed that maximizing PV deployment leads to increased electricity imports to balance the difference between supply and demand. Solutions containing larger storage capacities still relied on electricity imports for balance. This offset the effect of reducing the coal consumption on the import ratio and prevented the import ratio to lower beyond 36%.
The GHG emissions are affected the same by each deployment strategy. The data indicates a linear relationship between introducing PV and lowering GHG emissions. The results showed that the combination of rooftop and open-field PV is the most cost-effective strategy.
The diversity is increased the least by the open field, and the most by the rooftop PV deployment strategy. This finding is not supported by secondary literature. Previous research reported a negative effect between increasing PV and diversity. This indicates that the simplicity of the HHI index does not incorporate all real-world effects



(a) Overall impact of deployment strategies on the import ratio



(b) Overall impact of deployment strategies on the GHG emissions



(c) Overall impact of deployment strategies on the HHI

Comparing the results to the current sectors also revealed some general conclusions. This showed that introducing PV into the electricity and heat sector has a limited impact on the total installed coal (CHP) power plants, but does reduce their capacity factor significantly. Which leads to a positive effect on the import ratio and GHG emissions. Also, introducing large shares of PV does not require large additional investments in storage capacities. The data suggest that the currently available reservoirs and pumped hydro storage capacities can bridge the difference between supply and demand. However, the power output of the current storage facilities should be increased to accommodate the increased variability of the generation capacity.

The current conflict, the unclear outcome, and the current increased cooperation between the European Union and Ukraine will impact any forecast previously made to asses Ukraine's energy system. This research laid part of the groundwork for future assessments regarding the Ukrainian heat and electricity system. Which could ultimately lead to a sustainable and secure system in Ukraine.

Contents

1 Introduction

On the morning of the 24th of February 2022 Russia invaded Ukraine. Currently the outcome of the conflict is unclear, yet some of the impacts are. At the moment of writing this thesis around 6 million people have been displaced and numerous facilities have been destroyed. Since the start of the winter 2022 the Ukrainian energy and heat infrastructure is under constant threat of disruption due to Russian strikes at facilities and transportation networks. Exposing millions of Ukrainians to winter colds, hunger and loss of modern means of communication [1].

Restoring the infrastructure and mitigating the effects caused by the disruption are one of the highest priorities of the Ukrainian government. This resulted in the creation of "points of invincibility" centres where inhabitants can gather for hot food, shelter, and the charging of mobile devices. These are powered by fossil-fueled generators to operate independently of the current network. The existing electricity grid is very centralized, this is part of the reason Russia is able to disrupt the energy supply in such a large part of Ukraine. Of the total installed generation capacity 25% origins from four nuclear power plants and 10% from eight hydropower stations along the Dnieper and Dniester rivers. This system requires a large electricity transport network of more than a million kilometres long. The same is true for the heating network. This network consists of 33122 kilometres of pipelines and is powered by large, outdated and inefficient boilers [2].
Without diminishing current energy concerns, meeting greenhouse gas emission targets is also one of Ukraine's priorities. Ukraine has pledged to decarbonise its electricity infrastructure by signing the Paris Agreement in 2018 and being a member of the European Energy Community. A pledge further that is reinforced by becoming an EU candidate country in June 2022. This EU candidacy results in accepting the Fit for 55 legislation that are currently under construction. Despite large investments since 2010, in 2012 only 6% of Ukraine's electricity supply comes from renewable, non-nuclear, sources [3]. The low percentage of using renewable energy sources (RES) is not caused by the lack of availability. Ukraine has many sites suitable for wind, hydro and solar power. Also, the agricultural sector could provide large amounts of sustainable biomass [3].

Increasing energy security and reducing greenhouse gas (GHG) emissions could be achieved simultaneously. Using RES could help Ukraine to diversify its generation capacity, reduce electricity imports and decarbonize its energy sector. Photovoltaics (PV) is one of the main technologies that should be considered. If deployed on a large scale it's the third most affordable form of electricity after onshore wind and nuclear electricity. PV at the utility-scale is slightly more expensive but offers higher levels of decentralization [4].

After the 2014 Donbas conflict, Ukraine faced serious energy security risks. With the annexation of Crimea and part of the Donbas, Ukraine lost access to large coal and natural gas supplies. This led to renewed interest by researchers in the Ukrainian energy sector. Diachuk, Chepeliev, Podolets, *et al.* [5] Researched the share of RES that can be obtained between 2020 and 2050 for each decade. They showed that depending on regulation and subsidies, between 30 and 91% of the final energy consumption (FEC) can be met using RES. Another study from Child, Breyer, Bogdanov, *et al.* [6], focusing on the combination of storage and renewable energy, showed that 84% of the FEC can come from RES by utilizing several storage methods. The outcome of this conflict was a driver for their assessments, yet both authors do not explicitly relate their outcomes to energy security. Rather, energy security is often faced from a geopolitical viewpoint [7]–[9]. These studies are focusing on dependencies, power structures and historical relations. All identified the dependent relationship between the EU and Russia and, Ukraine and Russia. Often highlighting the fact that Ukraine is highly energy-dependent on Russian resources, while also economically dependent on gas transit fees for Western European gas markets. Combining the insights obtained from research on the Ukrainian energy sector while also addressing energy security could provide interesting insights.

The aim of this thesis is to research the effect of PV on energy security and GHG emissions in Ukraine. By addressing the following research question:

How do different PV deployment strategies reinforce energy security in Ukraine, while also help comply with GHG emission targets?

To answer this question various sub-questions need to be answered first:

- Which definition of energy security can be applied to Ukraine?
- What is the current status of the Ukrainian electricity and heat sector?
- What are the potentials and yields of renewable energy sources in Ukraine?

These questions are answered by literature review and simulations using optimization software. Therefore, the thesis starts with a literature review on future Ukrainian and European energy systems, followed by a review of suitable energy security key performance indicators (KPIs), current GHG emission targets and the status of the Ukrainian heat and electricity sector.
The KPIs are computed using a model of the Ukrainian heat and electricity sector built with the Calliope optimization framework. The Calliope software is used for its ability to generate optimal and sub-optimal solutions, with distinct geographical differences. This broad set of solutions allows for more perspectives as opposed to a single optimal solution.
The Calliope software requires various inputs, most prominently maximum potential capacities per considered resource and their time-dependent yields. These are generated on the provincial administrative (Oblast) level, based on literature research or geospatial analysis. The PV open field and rooftop potentials receive additional attention due to their relevance within this thesis. The optimization software will match generation capacity with demand in the most cost-effective way possible. Demand estimations for electricity and heat in 2030 are based on 2020 data from the Eurostat database [10], extrapolated based on the IEA roadmap towards net zero emission by 2050 [11].

Based on the technological differences three PV deployment strategies are considered, rooftop PV, open-field PV and a combination of both. By combining two different simulations their effects on the KPIs are evaluated. The first simulation maximises and optimizes the deployment of one PV technology. The second simulation determines the effects of small increments per technology.

After this introduction chapter 2 reviews the current literature on the Ukrainian and European energy systems, describes the research design and determines the measurements used to analyse the results. Chapter 3, Methods, defines the inputs used for the optimization, by explaining the individual assessments and data sources used for each input. It also describes the setup for the two simulations performed in this thesis. Chapter 4 contains the results of both simulations. Next, chapter 5, discusses the achievements and limitations of this research. Finally, chapter 6 contains the conclusion of the entire research.

2

Literature review

This chapter describes the theoretical basis of this thesis. section 2.1 is dedicated to reviewing previous research done on Ukrainian and European energy systems in order to define the knowledge gap. section 2.2 describes the research questions answered in this thesis. section 2.3 contains the literature review on suitable key performance indicators to assess energy security in Ukraine. section 2.4 describes the current GHG emission reduction targets. Finally, section 2.5 contains a short review of the current status of the Ukrainian electricity and heat sectors.

2.1. Previous work

The Ukrainian energy sector has been reviewed by various authors. These authors have their own intentions and focuses in their studies which slightly differ from each other. This section summarizes the motivation, methodology, results and major assumptions of the most recent and prominent authors. Additionally, it describes the research done on European-wide energy systems to highlight the importance of using a holistic approach when designing an energy system.

2.1.1. Reviewing the literature on Ukrainian energy systems

Diachuk, Chepeliev, Podolets, *et al.* [5] is the first research to be mentioned. This recent research determined a roadmap for Ukraine to reach a maximum share of RES by 2050. It is a collaborative effort between the National Academy of Science in Ukraine, the Heinrich Boell Foundation and the State Agency on Energy Efficiency and Energy Saving of Ukraine. The research was motivated by renewed energy security concerns from losing access to national coal deposits after the 2014 Donbas conflict, currently outdated nuclear capacity and the rising cost of energy sources. Also the price reduction of renewable technologies, higher social standards and international consensus on the need for transition was a motivation.

Diachuk, Chepeliev, Podolets, *et al.* modelled three different scenarios: the conservative, liberal and rapid development scenarios. The conservative scenario assumes that technological development freezes at the current level. Implying no increased efficiencies or reduced costs in the future. Under the liberal scenario are all efficiencies expected to advance while costs are decreasing driven by free competition. Lastly, for the rapid development scenario, it is assumed that governments will heavily invest in RES, increasing both their efficiencies and deployment rates while also reducing costs. All scenarios are evaluated using the TIMES-Ukraine model and the Computable General Equilibrium model. Inputs were estimated using macroeconomic parameters such as GDP growth, demographic compositions and technological forecasts.

This evaluation resulted in an expected share of RES of the FEC between 30 and 91% by 2050, depending on the scenario. Although energy security was not specifically analysed by the authors, the considered RES, solar, wind and biomass, decrease the import dependency of Ukraine. Consequently, increasing Ukraine's energy security.

The possibility of a 100% renewable, fully independent power system by 2050 is researched by Child, Breyer, Bogdanov, *et al.* [6]. The motivation for this research was four folded. First by the lack of previous research in this field. Second by energy independency issues. Also reducing GHG emissions and the wish to reduce the current dependency on nuclear capacity were a motivation for the research. They researched to what extent Ukraine can completely become independent of energy imports. Using the LUT (Lappeenranta-Lahti University of Technology) Energy System Transition Model they evaluated a 100% renewable scenario. Inputs for this model were derived from proxies such as windspeed and irradiance. Demand data is based on the 2017 data, extrapolated using key figures from the IEA to 2050. By including various renewable electricity generation, storage, sector bridging and transmission technologies, the authors showed that a 100% share of RES in the electricity sector is possible if supported by vast storage capacities. Child, specifically looked at electricity demand. This approach ignored the current intertwining between electricity and heat generation in Ukraine. Especially recent events show that both electricity and heat are important resources for Ukraine, and are preferably optimized in harmony.

Saha, Mettenheim, Meissner, *et al.* [12] looked at ways to reduce emission levels in the Ukrainian power sector by 2033. They concluded that Ukraine was not on track to meeting its international obligations, and analysed that the planned reforms were outdated and not cost-optimal. They also highlight that the current plans to retrofit the thermal power plants with filters, would also not comply with GHG emission reduction targets. By analysing five different generation compositions namely, a baseline current composition, one with reduced coal usage, one replacing coal with gas, one with a combination of the last two and one implementing RES scenarios, they intended to compare total system costs and compliance with GHG emission targets.
The authors analysed power production in Ukraine by 2033 using the optimal dispatch model to derive the minimum total cost for each scenario. They specifically focused on the year 2033. This year complies with the end of the transition period set by the European Energy community. This means they have to comply with all EU regulations on GHG emissions by this year.
Saha, Mettenheim, Meissner, *et al.* [12] concluded that for rapid emission reductions switching from coal to natural gas or renewable energy is beneficial, and more cost optimal than retrofitting the existing coal plants. More efficient with regards to meeting GHG targets would be replacing up to 50% of the current capacity with a renewable source. PV would be the main contributor with a market share of 16%.

Despite using all different models, scenarios, assumptions and forecasts a few general conclusions can be drawn from the papers as discussed above:

- All papers concluded that Ukraine can become more energy-independent, and meet GHG emission targets by transitioning towards RES.
- All these papers modelled Ukraine as an energy island, therefore not considering the possibility to import and export electricity to neighbouring countries.

Including the surrounding nations could broaden the existing knowledge of the future Ukrainian energy system. The following section will be evaluating research on European-wide renewable energy or electricity systems to determine their additional value.

2.1.2. Reviewing the literature in European energy systems

Tröndle, Lilliestam, Marelli, *et al.* [13], modelled a European fully renewable electricity system in 2050 and varied supply scale and balancing scale independently across continental, national and regional levels. Based on the Calliope software, they use a cost-minimizing linear programming model using a 4-hour resolution. With relatively conservative estimates of RES generation capacity for each region as inputs. Unfortunately, they did not include Ukraine because they focused on the ENTSO-E region, and Ukraine was not a full member at this date.
After varying the supply and balance scales between national and continental they showed that system cost and generation capacity are the lowest for Continental-scale supply and balancing and slightly increased costs for national-scale supply and continental balancing. This comes at an increased cost for more transmission capacity to facilitate energy trade. The continental supply decreased the variability of most RES, such as wind and solar. Local dips in yields could be matched with the surplus in other regions through trade and transportation throughout the continent. The increase in transportation capacity required was overall offset by a decrease in backup or peak generation capacity thus overall reducing the total system costs.

Child, Kemfert, Bogdanov, *et al.* [14], also simulated an European energy system. The authors simulated two pathways towards a 100% renewable power sector in Europe by 2050. The first scenario consisted of modelling the 20 regions independently, and the second one of the entire region with limited transmission options in between regions. This research included Ukraine and looked specifically at the electricity sector.
Using again the LUT model they computed for each scenario suitable generation compositions for each 5-year period between 2015 and 2050. They also showed that the overall generation capacity can be lower if transmission capacities increase. Their second finding concluded that more rapid decarbonisation is achieved if regions are better connected. This study included Ukraine but again only considered the power sector, also ignoring the intertwining between heat and electricity generation.

2.1.3. Adressing the knowledge gap

In short, this literature review shows that the Ukrainian and European-wide energy systems have already been researched but some knowledge gaps remain. [5], [6] are both motivated by geopolitical changes in east Ukraine and after the current conflict, these scenarios require updates. Energy security concerns are the common driver for reviewing the power sector, but it was mainly focused on import dependencies and resource availability. The current events show that the centralized nature of electricity and heat network are also limitations with regard to the security of supply. Including this KPI can provide additional insights into the generation composition of the power sector. Secondly, electricity networks between countries and regions are connected. This offers an increase in energy security and decreases each individually installed capacity requirement but at the cost of increased transmission capacity. [5], [6], [12] all looked at the Ukrainian energy system on a national scale, ignoring the benefits interconnection provides. Combining their detailed analysis of the Ukrainian power en heat sector with an interconnected model provides even more usable outcomes.
Lastly, not only Ukraine's electricity grid is susceptible to disruption, but so is Ukraine's heating network. As mentioned before, they are currently intertwined yet sometimes not considered in the scenarios [6], [12], [14]. Making changes to one system automatically impacts the other, and should therefore both be considered simultaneously. Analysing both sectors simultaneously again improves the usability of the outcomes for future reference.

Concluding, valuable insight might be gained by modelling a renewable electricity and heat system for Ukraine on a smaller regional scale. Including national and regional connections with surrounding countries. Secondly, by relating possible energy systems to energy security even more insights can be gained regarding possible additional costs or favourable deployment strategies by 2030.

2.2. Adressing the research question

After establishing the knowledge gap in the literature that this thesis attempts to complement, this section describes how the research question has been formulated:

How do different PV deployment strategies reinforce energy security in Ukraine, while also complying with GHG emission targets?

Before the main research question can be answered, a few other sub-questions have to be addressed. Starting with the definition of energy security because it is loosely defined, and susceptible to changes. Before the possible outcomes can be related to energy security, first the definition has to be determined. The applicability of this definition has to match the outputs and scope of the research method. This results in the following sub-question:

Which definition of energy security can be applied to Ukraine, and the models' outcome?

The definition of energy security is followed by researching what kind of technologies are currently used, and where they are located. What characterizes the Ukrainian energy and heat system, is it efficient, centralized or decentralized? How much electricity and heat are expected to be consumed in 2030, and at which time? In other words, all the specifics, quirks and factors required to accurately model Ukraine's electricity and heat systems, formulated as:

What is the current status of the Ukrainian electricity and heat sector, and what is it expected to be by 2030?

Before any meaningful full renewable changes can be applied, their possible locations, potentials and yields have to be established. Currently, we will consider the main forms of RES, solar, wind, biomass and hydropower, but also which forms of generation capacity are currently installed and how they perform. This results in the third and last sub-question:

What are the potentials and yields of (renewable) energy sources in Ukraine?

2.3. Determining suitable energy security KPIs from literature

Energy security as a definition is dependent on context, zeitgeist, and perspectives. Energy security historically meant security of supply [15]. This definition was based on Western concerns regarding the availability of resources and the risk to supply disruption, caused by events such as the 1970 oil crisis and 9-11. The awareness of climate change and societal dependence on electricity reshaped the definition towards; ensuring sustainable and reliable energy supplies at affordable prices [16]. Due to this changing definition and multi-dimensional aspects, many different indices exist.
Two major groups exist, aggregated indices and disaggregated indicators. The aggregated indices are often based on the same principle, a set of indicators is grouped by characteristics, such as availability, affordability, efficiency, environmental sustainability etc. [17]. The number of indicators differs per index, for example, the Energy Indicators for Sustainable Development uses 30 indicators, and the Asian-specific Energy Research Centre uses only 5 [18]. Although energy security is hard to capture in a single number, aggregating values raises debate between scientists about the methodological approach to selecting indicators, setting weights to the indices and concerns regarding sources [17], [19]. Next to the aggregated indices, there are dis-aggregated indicators such as the energy security indicators by the OECD [20]. These suffer from the same controversy, that singling out an indicator does not tell the whole story.

To select the most relevant index, a deeper dive into a select few indices is necessary. The choice of indices is based on availability, institutional acceptance, and prior applicability to Ukraine. Following Narula and Reddy (2015) [18], the "World Energy Trilemma Index" from the World Economic Council [21], the "International Index of Energy Security Risks" from the US chamber of commerce [22], and the "Global Energy Architecture Performance Index" from the World Economic Forum [23] are selected. In addition to the method of Narula and Reddy, the method of Kharazishvili, Kwilinski, Sukhodolia, *et al.* [24] is analysed because it is specifically tailored towards Ukraine and was published recently in 2021.

The major conclusion drawn from analysing these indices is that it is outside of the scope to recompute the energy security score based on the Calliope outputs. Because Calliope does not calculate all the data required to recalculate the summarizing score. For example, the Trilemma Index uses a group of indicators called "Country context" composed of macroeconomic stability, the effectiveness of government and innovation capability. These indicators are assessed using questionnaires, and other indices. In the Kharazishvili, Kwilinski, Sukhodolia, *et al.* paper, 9 out of 42 indicators are based on expert judgement. The International index and Energy Architecture index use mostly quantitative indicators such as fuel imports and energy consumption per capita, values that could be reevaluated based on Calliopes output as a proxy. Nevertheless, the databases used as a basis for computing the index scores are not publicly accessible.

Extraction of a single indicator is the next best thing but has two main drawbacks. By selecting a few indicators, which can be evaluated using calliope outputs there is an increased chance of biased results [17], [19]. Second, many indicators impact each other, requiring them to be mutually selected to display their interplay. For example, while out phasing coals plants by transitioning to PV, might decrease import dependency, increasing energy security in general. The same transition might also lower the diversity of generation, resulting in a decrease in energy security.
Taking these drawbacks into account, 2 indicators have been selected from the three big indices, diversity of generation capacity and import dependency.

The diversity of generation capacity is considered in all indices [21]–[23]. The higher the diversity the less a country is dependent on a single resource or technology. Diversity in generation capacity is measured using the Herfindahl-Hirschman index (HHI) and expressed as:

$$HHI = \sum_{0}^{n} G_n^2 \tag{2.1}$$

Here G_n equals the marketshare of each nth resource. The HHI index score of 1 means a total monopoly of a single capacity and near 0 scores resemble very diversified capacities. The simplicity of the HHI index comes with a downside, it does not recognize regional diversity, for example, if every region is completely powered by a single resource, and every region is powered by different resources. This could result in a low national HHI score, which would not translate into energy security. To prevent this from happening also the HHI scores of each independent region are calculated. The reported HHI values in **??** are the means of all the regional HHIs.

All indices are in consensus that high dependency on imports means higher risks to energy security. The specific definition for this metric, "Net [resource] import as a percentage of total national [resource] supply" is copied from the International index [22] for two reasons, first to be consistent, and the required data necessary can be obtained from Ukraine's energy balance [10], and Calliopes output. To calculate the import dependency correctly, the consumption of fuels outside of the electricity and heat sector is included. These values are also retrieved from the energy balance. Import dependency is expressed as:

$$\text{Import dependecy}_i = \frac{\sum_{t=1}^{t=8760} \text{Fuel consumption}_{t,i} + \text{ General fuel consumption}_i}{\text{Fuel production}_i} \tag{2.2}$$

In line with the IEA definitions, the following resources are evaluated: solid fossil fuels, peat and peat products, oil shale and oil sands, natural gas, oil and petroleum products, renewables and biofuels, non-renewable waste, nuclear-heat, electricity and finally heat [10]. From this list, manufactured gases, oil shale, oil sands, and nuclear heat can be dismissed as they are currently not used in Ukraine's electricity and heat sector and will not be added since this report is interested in renewable energy.

2.4. Determining the GHG emission targets

The optimization results from the experiment conducted for this thesis will be analyzed based on energy security as well as compliance with GHG reduction targets. This section describes the targets as set by international agreements and by Ukraine itself. It will then discuss the current status of these goals, followed by the implications for the electricity and heat sector.

Ukraine has pledged itself to the following international agreements, the Paris Agreement in 2016 [25], UN sustainable development goals (UN-SDG) in 2021 [26], several EU-funded energy programs since 2016, and more recently the fit for 55% plans by becoming an EU-candidate member state [27]. Ukraine signed the Paris Agreement on April 22, 2016. This agreement set the goal of a 35% reduction of GHG emissions compared to the 1990 reference level.
The EU Fit for 55 program is currently under development, yet it is clear that it will overrule the Paris goals of emission reduction. The EU goal is to reduce the overall EU emission by 55% as compared to the 1990 reference level. The reduction required per member state differs and is currently being debated, the outcome and implementations will be described in the national emission reduction plans (NERP).

Figure 2.1 shows the latest reported GHG emissions since 1990 by the IEA [28]. If the total GHG emissions are reviewed (left) even the strictest target, the Fit for 55 target, is already met. This would imply that the current electricity and heat sector do not require any transition towards more sustainable resources. This decline in GHG emissions is mainly caused by a decline in population, and economic activity since the fall of the Soviet Union [3]. A better KPI is the GHG emissions per total energy supply. This KPI shows a much less steep downward trend, affirming the fact that the generation composition did not change much since 1990. All authors specifically assessing the Ukrainian power sector [5], [6], [12] also recognize this fact and deemed the Ukrainian national contribution towards the Paris Agreement not ambitious. Diachuk, Chepeliev, Podolets, *et al.* (2017) [5] set an intermediate and more ambitious goal of emitting a maximum 100 $MtCO_2$ in the electricity and heat production sector by 2030. Because they expect that the international community will request additional efforts made by Ukraine. This is also in line with the Fit for 55 policy that might request additional efforts to be made from individual countries in order to reach an overall reduction of 55% in the entire EU. For the same reason, this threshold is adopted as the benchmark to evaluate if the generation compositions meet the GHG targets.

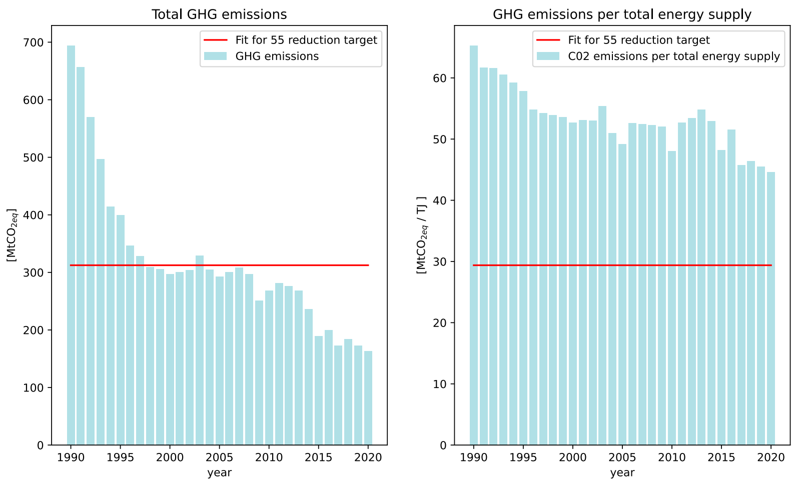


Figure 2.1: Overview of the GHG emissions since 1990. Left: Total GHG emissions and the FIT55 target. Right GHG emissions per TES and relative 55% reduction [28].

2.5. General description of the electricity & heat sectors

Before redesigning the Ukrainian electricity and heat network, it is important to know about their current systems, composition, and strong and weak points. Every 5 years, the IEA reports the current status of Ukraine's energy system in a detailed report [2], it also includes Ukraine in the Eastern Europe, Caucasus and Central Asia, Energy Policies Beyond IEA Countries Report [3]. Together they provide an all-encompassing overview of energy policies, strengths, weaknesses, and opportunities regarding both the electricity and heat sectors in Ukraine. This section provides a summary of the main relevant findings.

Firstly, Ukraine has access to abundant fossil sources, it is rich in coal, natural gas and uranium deposits. These deposits are mainly located in the eastern part of Ukraine. After the 2014 Donbas conflict coal production and supply dropped significantly by 22.4%. This was caused by damage to facilities and loss of territories [3]. The coal in Ukraine is of low quality, meaning it can not be used in steel refineries, and using it for thermal power plants requires additional post-process filtering to meet European air quality regulation standards [12]. Despite this drawback, Ukrainian coal has historically been used as a main energy supplier for electricity in Ukraine until this day [10].
The Natural gas deposits are located in the Sea of Azov, from Odesa to Crimea, and are estimated to be around 5.4 trillion cubic meters. Most of these fields have never been developed due to the availability of more affordable Russian gas. Until 2022 Ukraine was a natural gas importer, and a major gas transit player for the European Union, therefore extended gas transit lines exist. Secondly, Ukraine contains a few of the biggest natural gas storage fields in Europe, totalling around 31 billion cubic meters [2], [29].
Thirdly, Ukraine has modest uranium resources, but it lacks enrichment or reprocessing facilities. For these last two, it is reliant on Russia. Because their soviet era nuclear reactors utilize different cores than Western reactors, which are only produced in Russia. The uranium can be found in central Ukraine in the Dnipropetrovsk oblast. After the 2014 Donbas crisis, the government expressed the desire to invest in national enrichment and reprocessing facilities, yet these plans lack industrial funding [2], [30].
Lastly, Ukraine is also endowed with abundant solar, wind, hydro and biomass resources. Except for hydro, these sources are largely untapped and their potential is discussed in more detail in the next chapter.

The availability of these resources shaped the current electricity sector in Ukraine consisting of around 56 GW of installed capacity. As discussed before, the backbone consists of around 14 GW of nuclear power plants, 25%, and 35.8 GW of thermal power plants of which 30 GW is supplied by coal. The remainder 11 per cent is fueled by hydro, gas and oil. Most of these plants were installed during the Soviet era between 1960 and 1980, and are currently in need of replacement or extended upgrades to meet the new greenhouse targets. For example, Saha, Mettenheim, Meissner, *et al.* (2021) [12] recommends retrofitting or replacing half the thermal power plants to meet the national emission reduction plans if Ukraine maintains its current capacity composition. This centralized power system requires an extended transmission network, in total 22000 km of transmission cables are currently installed in Ukraine [3]. The combination of outdated capacity and long transmission lines also results in relatively low overall efficiencies as compared to Western European countries. The IEA and the world bank therefore both recommend substantial investments for upgrading and updating the current capacities [2].

The heating network is compared to the electricity network less centralized, but even more, extended with 33122 km of pipelines. It's mostly fueled by boilers, utilising gas and biomass, but regionally it is also connected to local thermal power plants. The IEA [2] reports that currently, the installed capacities are excessive, caused by large inefficiencies in the systems. Lack of maintenance, outdated equipment results, and insufficient insolation result in almost 17% losses systemwide. Additionally, breakdowns are frequent, it is estimated that 1.6 breakdowns occur per km of pipeline per year.

The current status of Ukraine's energy and heating system and the current increased energy security risks show that an overhaul is necessary. The next chapters will discuss the potential of RES in Ukraine and shall determine if deploying these could provide Ukraine with a more robust energy and heating system in the future.

3 Methods

This section describes the process, method and assumptions made to define Ukraine in the Calliope optimization framework and it will highlight which parts deviate from the Euro-calliope approach. It starts by explaining which optimization software is being used, how data is being collected and describes the choice for regionalization and the weather year input in section 3.1. section 3.2 explains which historical year is used as the input year. Third, the demand for both the electricity and heat sector in section 3.3 and section 3.4 is analysed. To bridge the gap between supply and demand, section 3.5 describes how the transmission network capacities are determined. The potential of the considered sources of renewable energy is described in section 3.6. Finally, section 3.7 ends by describing the settings of the different simulations.

3.1. Research design choices

3.1.1. Optimization software

The research in this thesis is designed around using the Calliope optimization framework. Foremost because of its ability to do modelling to generate alternatives (MGA). Instead of resulting in a single optimal solution, Calliope will offer a range of solutions that are equally feasible but not cost-optimal. To be specific, the sub-optimal solutions are also geographically different resulting in so-called SPORES (spatially explicit practically optimal solutions). Studying the range of solutions provides additional insights into which technologies match, which locations should most likely be occupied by a specific technology and therefore offering a more valuable conclusion [31].
Secondly, one of the authors, Dr Pfenninger, is supervising this thesis. Being able to use his insights and experience with this software is invaluable. Pfenninger is also the author of Euro-Calliope a branch of the Calliope software used for various European energy systems-related researches [13], [32]. Following the assumptions and approach made in this research might allow for easily integrating Ukraine into the Euro-Calliope framework. Adding additional value since Ukraine only recently joined the ENTSO-E in 2022.

3.1.2. Collection blueprint

The choice of Calliope as the optimization framework, combined with the wish to define Ukraine in line with the other European countries as defined in Euro-Calliope, sets certain constraints and requirements for the input data for various inputs. If available, this paper will use the same data sources as used for the Euro-Calliope branch [32]. In many cases this data is not available, often caused by the fact that Ukraine became only recently an EU candidate. In those cases, equivalent internationally recognized databases are used as source material. If these are not available, the Ukrainian statistics (UkrStat) bureau was consulted for their most recent data [33]. Additionally, when conflicting data exists, or only general assumptions can be made, choices are always made conservatively with regard to their final impact. This is done to develop a robust definition of Ukraine in Calliope.

Data on technology cost estimations are limited by the optimization year. The Euro-Calliope framework contains cost estimates for 2030 and 2050. Considering the relevance and short-term impact this research could make, 2030 is the year for which the optimization is run.
Lastly, both research on European-wide energy systems [13], [14], [32] and current data [34] show that the Ukrainian electricity system is not independent of its neighbouring countries. Trade between Poland, Slovakia, Hungary and Romania occurs based on the free market principles. Historical obligations with Russia, Crimea and Belarus are even upheld despite current hostilities. Moldova is an even more special case, this country relies heavily upon Ukrainian exports since the separation of Transnistria [3]. To include these factors, both data and estimations about trade volumes between these nations are included in this research.

3.1.3. Regionalization

The applicability and relevance of this research are greatly impacted by the geographical definition of Ukraine inside the Calliope framework. Smaller regions offer more detailed information about RES capacities and energy flows. Diaduk, Child and Saha [5], [6], [12] all modelled Ukraine as a single node in their research. While the research on European-wide energy systems subdivided Europe into either bidding zones [32], or nations combined with macro-regions with natural areas of cooperation [14]. Modelling Ukraine as a single node benefits from more accessible data and thus needs fewer assumptions. On the downside, this research has already been done, and it does not offer any insights into regional dependencies. Dividing Ukraine into bidding zones offers no advantages. Ukraine consists of 2 bidding zones, the IPS and BEI. All oblasts with the exception of the most western oblast, Zakarpatia, exist inside the IPS zone [35]. The BEI was separated due to historical reasons, the location allows for electricity trade between Poland, Slovakia, Hungary and Romania [2]. To bridge the gap between the existing national research and offering a more detailed outlook, and taking into account the availability of reliable data, the choice is made to define each province, also known as an oblast, of Ukraine in Calliope. This should offer a more detailed solution as compared to the other national Ukrainian models.

3.2. Choice of weather year input

The weather is one of the most influential inputs for all models used to generate inputs and results. It is vital to use a reference year with unfavourable weather conditions for RES, to prevent optimistic outcomes, but this might simultaneously lead to an overestimation of total costs. Using the typical meteorological year (TMY) can be used as an alternative but this leads to the exclusion of extremities. This section describes in short how the input year has been determined. The choice of available input years is first limited by the applicability of various tools used for this thesis and further selected based on its root mean square error (RMSE) to the TMY. The weather data is retrieved from the ERA-5 database [36].

To maintain the interplay between weather, electricity and heat consumption and demand this thesis uses the When2heat [37] model and retrieves data from Renewables.ninja [38]. This limits the choice of available weather data to the years between 2015 and 2020. Next, further selection out of this time period is based on 4 parameters and their RMSE to the TMY. Based on their relevance, 4 parameters have been selected from the database. The first is the temperature at 2 meters height because this largely determines the heating demand. The second parameter is the wind speed at 10 meters in height since the wind capacity factors are based on this value, heat demand is to some degree also affected by this parameter. The same goes for the surface solar radiation downward concerning the PV capacity factors and cooling demand. Finally, the precipitation is selected because this parameter highly influences all the hydro capacity factors and storage opportunities.

The RMSE of 2018 is the lowest compared to the TMY, meaning this year's weather pattern is most closely related to the TMY. As such, 2018 is chosen as the input year for all weather-related variables.

3.3. Constructing the 2030 electricity demand profile

This section describes the process of estimating the electricity demand in Ukraine in 2030. Four different sectors are being considered namely; Industry, residential, transport, and commercial and non-specified. In case of ambiguity, the scope and meaning of the sectors are defined. For each sector, the current electricity consumption and the method to determine the 2030 total consumption and time series are described. In the final section, the total electricity demand is verified against the most recent 2021 actual electricity demand.

Most predictions about future growth and reasonable 2030 targets are based on the paper by Diachuk, Chepeliev, Podolets, *et al.* [5]. For all the considered sectors they reported 2030 targets. Second, the goals as set by the IEA roadmap towards net zero carbon in 2050 [11] is used as a guideline for reasonable growth predictions and targets.

3.3.1. Industry

The industry sector can be defined and subdivided in various ways. The IEA, Eurostat and the OECD subdivide the industry sector into 13 parts, namely; chemicals and petrochemicals, non-ferrous metals, non-metallic minerals, transport equipment, machinery, mining and quarrying, food beverages and tobacco, cement, pulp paper and print, wood and wood products, textile and leather, construction, and non-specified [39]. While Ukraine's own statistic bureau UkrStat uses only three main industrial groupings, mining and quarrying, manufacturing and electricity, gas, steam and air conditioning supply [33]. Starting from 2015, Ukraine is reporting statistics to the Eurostat database in accordance with the EnergyStatistics guidelines (2004) [39]. The guideline groups all 13 different economic groups together in a single one, heavy industry. This definition allows for comparability with other nations, thus this definition will be used to define the sector's energy demand.

The heavy industry sector is with 165 PJ in 2020 currently the biggest consumer of electricity in Ukraine [10], [40]. Most of the energy is consumed in the processing, mining, and quarrying of non-ferrous metals, food beverages, tobacco, and chemical and petrochemical industries. Next to electricity, the industry sector also consumes 150 PJ of heat, mostly through burning fossil fuels. The IEA roadmap to net zero carbon emissions [11] describes the problems the industry sector faces with regard to decarbonization. Low margins and high capital costs combined with 40-year investment cycles prevent rapid switchovers to low-carbon technologies. They predict limited carbon reductions up until 2030, caused by increased renewables shares in the electricity generation mix. Nevertheless, in order to meet GHG emission targets, processes that can easily be electrified should have done so by 2030. The net zero carbon scenario estimates that 28% of the total energy consumption of the industrial sector can be consumed in the form of electricity by 2030 [11]. This implies for Ukraine that this sector will increase its electricity consumption to 202 PJ of electricity by 2030. Larger reforms such as switching over to hydrogen, and incorporating carbon capture and storage technologies are not foreseen in the IEA roadmap, nor by [5], by 2030 and are thus excluded from the demand.
Next to heavy industry, Ukraine has a smaller light industry sector. This sector consumed roughly 13 PJ of electricity, mainly in the agricultural sub-sector [10]. The IEA roadmap makes no specific predictions for the light industry but does mention the electrification of the vehicle fleet as a likely GHG emission reduction measure. Currently, the electrification rate of vehicles in Ukraine is 0.02% and is estimated to increase to 10% by 2030 (more information in section 3.3.3) [41]. The IEA roadmap reports similar growth in the agricultural sector. They estimate that the consumption of electricity in the agricultural sector will increase to 16 PJ [11].

2030 time series for both heavy and light industries are constructed using the following method. Yearly total consumption data was retrieved from the Eurostat database [10], and converted to 2030 estimates as described above. These values are the inputs for the DESStinEE model which transfers macroeconomic and annual electricity consumption data into yearly time series based on country-specific variables [42]. Data for Ukraine is not incorporated into the DESStinEE model and is collected for this thesis. Most macroeconomic parameters have been retrieved from the Eurostat database [10] or UkrStat [33]. Parameters that could not be retrieved, are estimated using the average value of the surrounding former Soviet states. The national time series is then projected into regional time series based on each region's share of industrial and agricultural GDP.

Heavy industry is mostly situated in the east of Ukraine and around the Sea of Azov, due to its historical access to trade ports and the availability of natural resources [43]. Many of these facilities are currently in a contested area, with the Azov Steel factory as a prime example, see Figure 3.1. The agricultural sector, as a proxy for the light industry, is differently subdivided over the regions, with a more gradual spread in central Ukraine, as depicted in Figure 3.2.

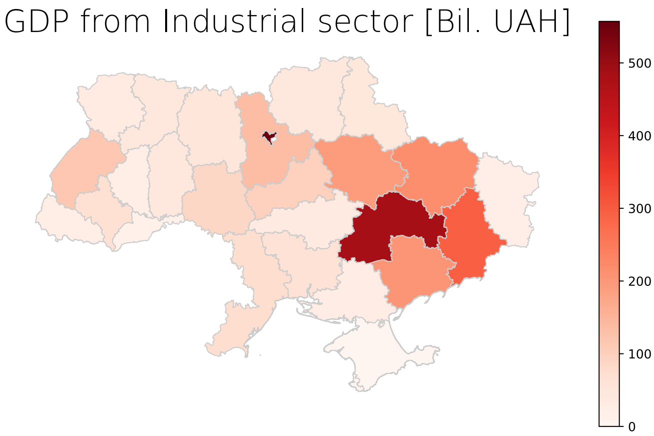


Figure 3.1: Industry GPD per region in 2018, data excluded Crimea and the city of Sevastopol [43]. The total electricity demand for the heavy industry is estimated using the DESStinEE model, and subdivided according to the industrial GDP of each region.

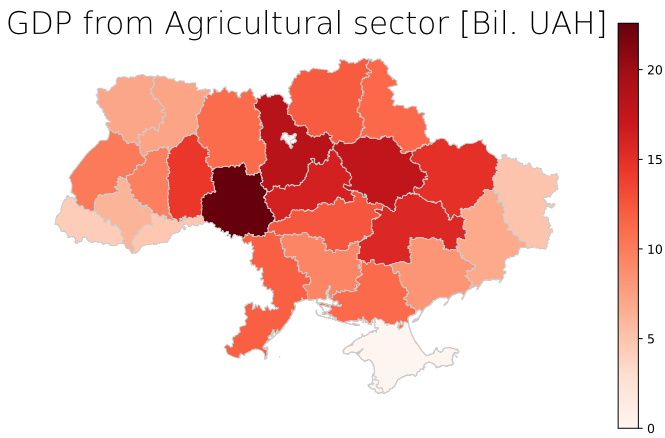


Figure 3.2: Agricultural GPD per region in 2018, data excluded Crimea and the city of Sevastopol [44]. The total electricity demand for the light industry is estimated using the DESStinEE model, and subdivided according to the agricultural GDP of each region.

3.3.2. Residential

The residential sector is with 572 PJ the second largest energy consumer in Ukraine [10], [40]. This energy is mainly consumed in the form of natural gas for heating and cooking purposes (Figure 3.3) [3]. Electricity, with 132 PJ, is the second largest resource and can mainly be contributed to household appliances. More specific data about electricity use for heating in residential buildings is unavailable, therefore it is assumed that 132 PJ is used directly as electricity. District boilers supply 65% of Ukrainian households with heat and only approximately 0.05% of these boilers use electricity as a fuel [5]. The energy demand for space heating is analysed separately in section 3.4.

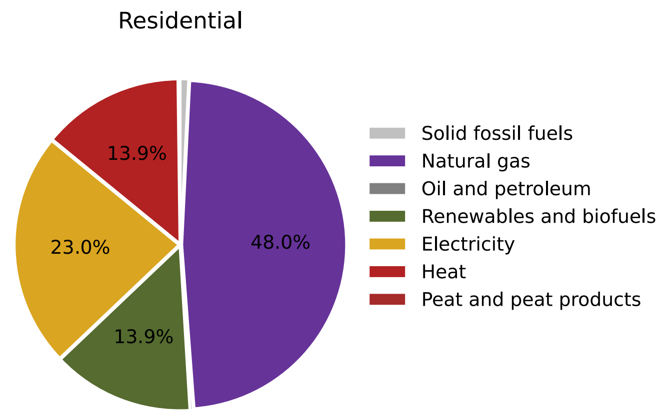


Figure 3.3: Shares of main fuel types of the final consumption of the Residential sector [10]. Currently, the residential sector already consumes large amounts of electricity, mainly for household appliances. Natural gas is still the main energy form to supply heat to the residential sector

The net zero emissions roadmap [11] expects a decrease in energy and electricity use for residential buildings due to increased efficiencies and declining populations with 1.2% per year. This offsets the increase caused by the electrification of appliances and heating. The 2030 electricity use is also affected by decentralized PV deployment strategies. They can greatly impact the type of energy consumed in the household sector. The rule of thumb is that with an increased amount of home PV systems, electricity consumption also rises. Economic factors such as EV penetration, PV ownership, and feed-in tariffs play an essential role. Yet, non-economic factors such as resilience to outages, independence, and self-sufficiency are also of influence [45]. Modelling these secondary effects is outside of the scope of this report. The decline in electricity use is also foreseen by Diachuk *et al.* [5] they expect a drop from 130 PJ to 88 PJ.

The national time series for residential electricity use is again constructed using the DESStinEE software and are redistributed over the regions based on the population. Population levels are based on the Global Human Settlement layer database [46]. This database contains for each 100 m^2 the number of inhabitants and building density. This data is analysed using the free and open-source geographic information system Qgis 3.28. The regional total populations are depicted in Figure 3.4.

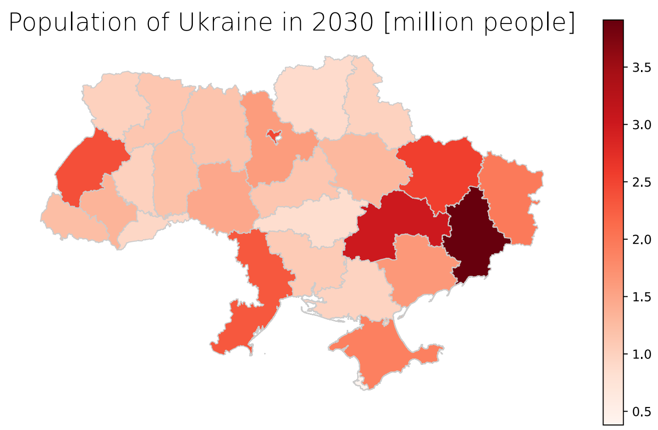


Figure 3.4: Population per region in 2020 [46]. The national electricity demand is estimated using the DESStinEE model and subdivided according to relative population shares per region.

3.3.3. Transport

The third sector to be considered is the transport sector, it is also the third biggest final energy consumer in Ukraine. In accordance with the International Energy Agency and Eurostat and OECD [39] definitions the subdivisions are: road, air, pipelines and inland navigation. Of these categories, light vehicles (road) and trains (inland navigation) are currently partly electrified and have the potential for growth by 2030. Air transport and pipelines are not considered to be electrified by 2030 according to the IEA Roadmap. GHG reduction targets for air transport are envisioned to be met by raising the percentages of biofuel in the fuel economy [11]. Ukraine has a large gas network traditionally used for transporting gas from Russia to Europe, the required pumps are fueled by gas. Adaptations of these systems face the same problems as heavy industry, high capital costs and investment cycles. Therefore both are not expected to have a significant impact on Ukraine's 2030 electricity consumption.

According to the Eurostat database [10], the final energy consumption of road transport is 283 PJ and is currently mainly fueled by oil and petroleum products (99%), natural gas and biofuels make up for the remaining percentage, as depicted in Figure 3.5. Electric vehicle penetration is low, at 0.02% mainly caused by a lack of services, such as charging and maintenance [41]. Ukraine has the intention to grow its electric fleet, expressed through signing the Association Agreement with the European Union [41]. Also, the net zero emission scenario from the IEA roadmap expects worldwide increased shares of EVs. Diachuk, Chepeliev, Podolets, *et al.* expects electricity use in the transport sector to rise to 33 PJ. This is a 10% increase in comparison to the 2020 consumption [10].
The final energy consumption of rail transport is 17.5 PJ and is currently mostly electrified (Figure 3.5) [10]. Resulting in a yearly electricity demand of 16.6 PJ. The level of electrification is already above the 2030 thresholds from the roadmap predictions. Any forecasting related to further penetration by 2030 of electricity use in rail transport is insignificant.

The DESStinEE software produced yearly time series for both the road and rail transport sectors. These are subdivided into regional time series based on population for (light) road (Figure 3.4) and industrial GDP per region for rail (Figure 3.1).

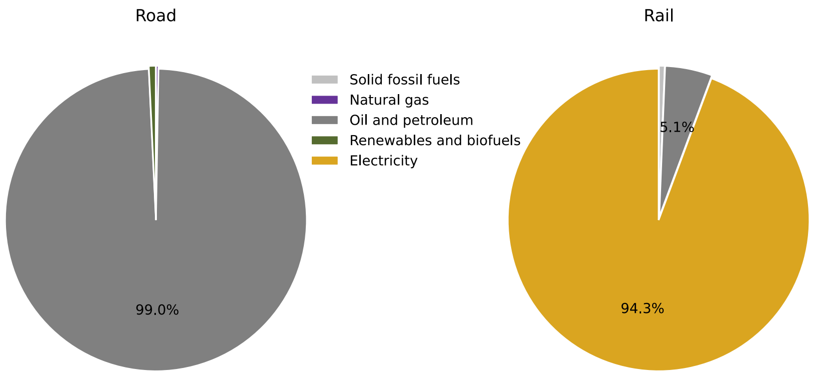


Figure 3.5: Shares of main fuel types of the final consumption of the (light) road and rail categories [10]. left: Road transport relies mainly on oil for its energy supply. Despite a lack of services, it is expected that roughly 10% of road transport can be electrified by 2030. Rail transports however are already mainly supplied by electricity. Further penetration of electricity is not to be expected by 2030.

3.3.4. Commercial and non-specified

The last remaining sectors are commercial and non-specified. They are considered together due to their share and size, relative to the other sectors. In total, they consume 245 PJ of energy, of which about one-third is in the form of electricity (90 PJ) [10]. Due to the lack of data about the consumers, this load is assumed to be distributed uniformly throughout the year. The regional division is based on the total population per region [46]. Consequently, no growth predictions are made about 2030 consumption.

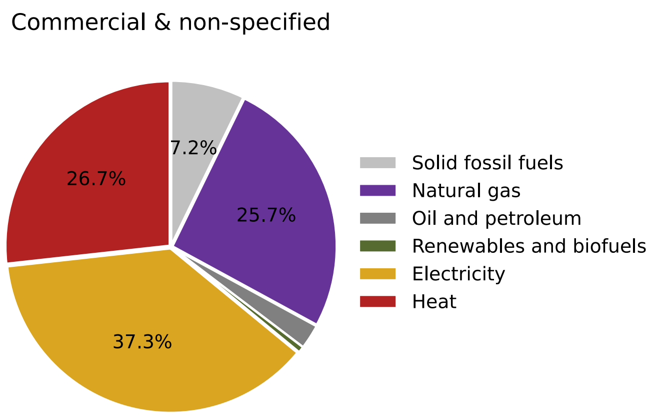


Figure 3.6: Shares of main fuel types of the final consumption of the commercial and non-specified sector [10]. Currently, 90 PJ of electricity is consumed in these sectors. Due to a lack of data, this value is not extrapolated to 2030 and uniformly distributed over the regions

3.3.5. Validation of the electricity demand profile

After establishing individual sectors' demands they are aggregated and validated against the actual dispatch data from the ENTSO-E. This section describes this process.

The total demand for 2030 is compared to the actual dispatch of Ukraine's generation capacity from the ENTSO-E [34]. This agency, the European Network of Transmission System Operators for Electricity, has published data about the Ukrainian transmission network since 2019. With regards to load data, only the 2021 database is complete. The 2030 load data is compared to the 2021 actual data on 4 parameters, total demand, correlation with the mean temperature, their standard deviation, and load duration curve. This allows for a validation of the cumulative time series.
By comparison of the total load, the assumptions with regard to sector choice can be verified. Secondly, it validates the input values from the Eurostat database. The total demand in 2021 was ± 131 million MWh after deducting exports and adding imports to other nations and compensating for transmission losses. Evaluating the total load reveals one major deficit, underestimation of the total load by the aggregate demand. This is caused by the selection of sectors, which automatically also excludes various sectors. Diachuk *et al.* [5] estimates that the total electricity use in 2030 equals roughly 160 million MWh. Figure 3.7 (upper) shows that initially, the aggregated demand curves predict a lower total. The inclusion of more sectors does not make up for the difference, based on the Eurostat database, already 80% of all demand is covered. By adding a baseload, proportionally disaggregated over the regions, the 2030 demand curves equals the prediction by Diachuk *et al.*

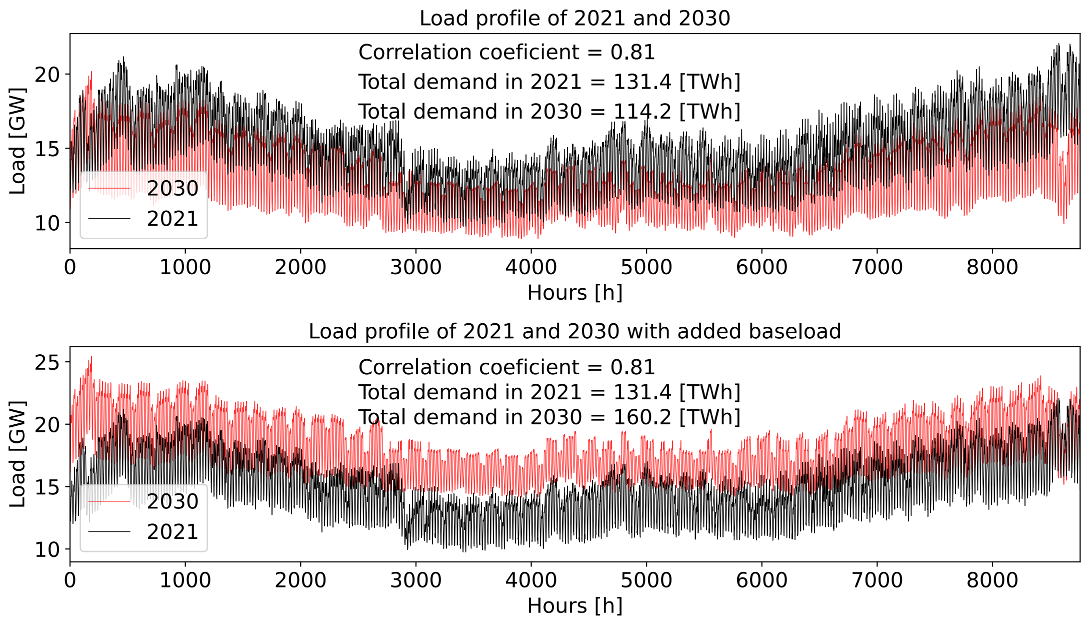


Figure 3.7: 2021 and 2030 demand curves, upper: without additional baseload. The upper graph shows that there is a strong correlation between the estimated demand curve of 2030 and the actual curve of 2021. The total demand is lower than estimated by [5], to compensate a baseload is added.

Correlation with mean temperature is the second validation parameter. It encapsulates the interplay between the weather and the electricity demand. For comparison, the average ERA-5 2-meter height temperatures for 2018 and 2021 in all of Ukraine are plotted against 2030, and 2021 demand curves [36]. As a reminder, the 2018 temperatures are being used in the correlation calculation for 2030, since this is the reference year for all weather-related inputs in this optimization. The 2021 demand and weather data correlate with -0.40, and the 2030 demand and the 2018 temperature data correlation is -0.36, as depicted in Figure 3.8. This shows that the temperature dependency of the modelled time series is in line with the actual ENTSO-E data. Which improves the level of realism of the model

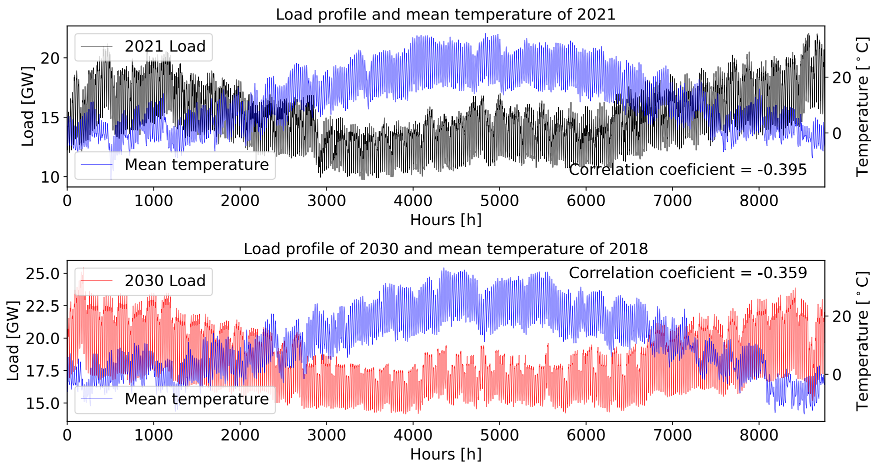


Figure 3.8: 2021 and 2030 demand curves and correlation with their underlying temperature. Correlation with the weather input year 2018 and the estimated demand curve is comparable to the actual 2021 curve and temperature. Indicating that the models used to estimate the demand, produced reliable results

The standard deviation provides insight into both the seasonal variation as well as in the daily variation. If the variances do not align this would mean that the time series do not depict the seasonal and daily patterns correctly. For completeness, the standard deviation for the entire year is calculated, as well as for a typical winter and summer week. The results are displayed in Figure 3.9. The deviations match and visual inspection and correlation of both load duration curves reinforce the observation.

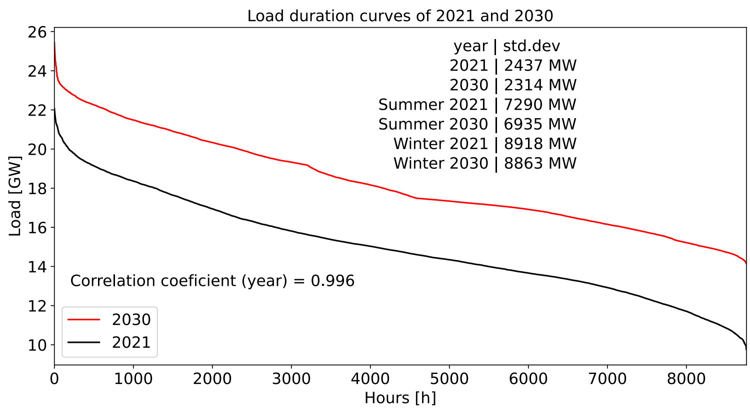


Figure 3.9: 2021 and 2030 Load duration curve and standard deviation for each year and season. The similarity between the load curves indicates that the models estimated a similar demand profile as the actual 2021 demand. The standard deviations show that daily and seasonal trends are comparable.

3.4. Constructing the space & water heat 2030 demand profile

The Ukrainian electricity and heat sectors are very intertwined, 41% of the installed generation capacity in 2015 existed out of CHP and nuclear power plants, both providing large amounts of heat [5]. Therefore this paper considers them both simultaneously. Heat demand is different for each sector, in the residential sector it can be further specified in space, water and cooking heat. The industrial sector has even more additional heat demands such as high-temperature heating. To limit the scope of this thesis the choice is made to focus on residential space and water heating. According to the Eurostat database [10], space heating accounted for 63% of the total residential heating demand in 2020, with 310 PJ, while cooling accounts for only 0.71%. Water heat demand consumed around 85 PJ of energy in 2020, as depicted in Figure 3.10.

Heating in major cities is often done using district heating systems consuming natural gas. These systems are notorious for their inefficiencies and implementing a mid-life update is amongst the highest recommendations from the IEA [3]. Secondly, there is a huge reduction potential by better insulating the current housings. It is estimated that insulating can save up to 46% of the 2012 energy demand [5] by 2050, of which 14% can be achieved by 2030 by implementing fast payback measures [5]. These savings and the decrease in population are slightly offset by an expected increase in consumption. This results in an estimated overall reduction of 4% in heating demand [5], [47]. The IEA does not provide us with a similar forecast for water heating, this is thus assumed to remain constant.

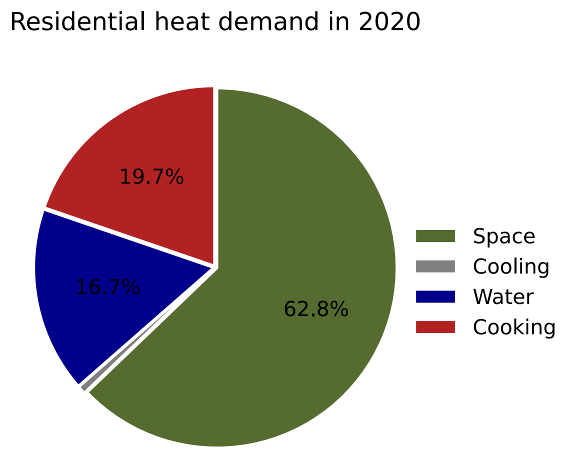


Figure 3.10: End uses of the residential heating demand in 2020 [10]. Space and water heating are the two main contributors to heat demand in 2020. Due to limitations on available data, only residential space and water heating are considered in this thesis.

Based on the 2020 values and energy-saving potentials, time series are constructed using the When2heat software developed by Ruhnau et al. [37]. This software transforms national and annual data into hourly time series for both space and water heating, based on weather and population data. The When2heat software calculations are mostly based on the same sources as those used in this paper. The annual demand is deducted from the Eurostat database [10], and weather data is from the ERA-5 hourly database [36]. To preserve the relationship between demand, supply, and the weather, the same input year, 2018, is used for the weather data. The only exception to the method described in [37] is the use of population data from Eurostat, this was not available for Ukraine so the GHS POP 2030 database [46] is used instead. This database has a bigger spatial resolution, resulting in a loss of accuracy.

3.4.1. Validation of the heat demand profile

The constructed residential heating demand is verified using the temperature correlation and checking the total demand with literature. The time series for space heating and water heat demand are plotted, in Figure 3.11, and they clearly show a daily trend. Space heating is also affected by seasonal temperature fluctuations and shows a clear dip in the summer months. It is fairly correlated, -0.673 to the underlying temperature of 2018. Water heat demand on the other hand only shows a daily trend with a daily peak in the evening and around noon. The water heat demand is fairly constant throughout, and uncorrelated to the temperature, which corresponds to the when2heat [37] definition of water heat. The total heat consumption of 35 TWh is also in compliance with the estimations from Diachuk *et al.* [5]. Who predicted a total heat consumption of 32 TWh for the household sector by 2030.

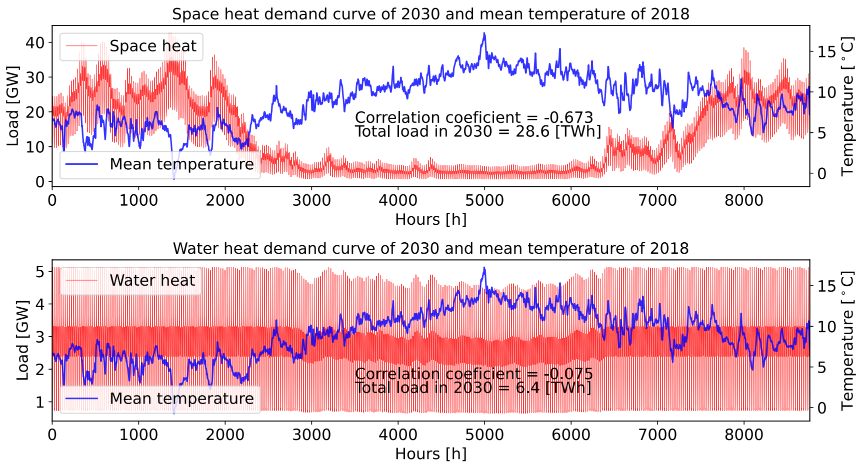


Figure 3.11: Space and water heat demand curves of 2030, plotted together with the underlying 2018 mean temperature. The negative correlation between space heat demand and temperature indicates that the model made reasonable predictions. The overall heat demand of 28 TWh is in accordance with estimations from [5]. Water heat shows a strong daily pattern not correlated to the temperature, which is in accordance with the when2heat predictions [37].

3.5. Assessing the transmission capacities

To bridge the gap between demand in the previous sections and supply in the upcoming sections, this section will discuss the transmission capacity between regions and nations as defined for this thesis.

Capacity

Regional and international transmission capacity is manually retrieved from the ENSTO-E grid map [35]. This map contains all transmission lines of 220 kV and higher from all European transmission system operators. Due to the nature of the optimization software, transmission between regions happens from the centre of one region to the next. This deviates from the real world where generation capacity is placed more diverse throughout a region. Secondly from the grid map, we see that there are often multiple individual connections between the same regions, often due to geographical reasons and the existence of large, nuclear and hydro, powerplants. Here the Calliope model deviates again from the real world by modelling these multiple connections as a single connection. The 2030 transmission capacity is not expected to be much larger than the current capacity. Planning, building and funding these projects often takes several years, therefore the optimization is limited to a maximum of 10% increase in transmission capacity with regards to the current 2022 levels.

International trade

As described in the previous chapters currently no European country is a complete autarky. In 2021 Ukraine traded with Poland, Hungary, Romania, Moldova, Slovakia and even Belarus and Russia. Electricity was imported and exported from all nations with the exception of Poland (only imported) and Moldova (only exported) [48]. Trade between nations is a complex interplay driven by supply and demand, it is outside of the scope to model all parameters involved in this process. To include the effects of cross-border flows on generation capacity, all the other countries of the ENTSO-E are included in the model on a national scale.

Moldova, Belarus and Russia are not part of the ENTSO-E and are not defined in Euro-Calliope. In this thesis, they are included in a simplified manner, to allow for cross-border trade. Their imported electricity demand in 2030 is based on the actual imported electricity from Ukraine in 2021 [48]. This forces the optimization to take electricity exports into account, especially valuable for Moldova. To correctly take both imports and exports into account between countries, both countries must be fully defined in the Calliope. Completely defining Belarus and Russia for Calliope is outside of the scope of this work, thus only their electricity imports are being considered.

3.6. Determination of potential and yield per renewable energy source

This section describes the potential of various renewable resources in Ukraine. It explains in detail how the regional potentials are assessed and how the time series containing the capacity factors are constructed.

3.6.1. Solar power

Solar energy is the main source of energy on this planet. In Ukraine, the average annual total solar irradiance is between 1070 and 1400 kWh/m^2 [49]. This paper considers three different PV deployment strategies, rooftop, open-field and combined. Open-field PV is more economically viable and offers higher yields, rooftop PV offers a higher level of decentralization and independence for the end user, and the combination might show additional insights. This section describes the process of determining the capacity potentials and yields of open-field and rooftop PV.

Research on the total regional solar potential is limited, recent findings published by the Institute of Renewable Energy from the National Academy of Science in Ukraine (IRE NAS), estimated a total potential of 83 GW [49] divided over the 27 regions. The IRE NAS did not diversify between rooftop or open field PV. The rooftop and open-field potentials are estimated using geospatial analysis. This method follows the approach used in the Euro-Calliope research paper [32]. This research estimated a conservative and sustainable open field PV potential, by only not considering land that is being used for agriculture, nature protection or buildings. As well as, unsuitable areas with forests, dense vegetation, water bodies and steep slopes. Based on data from the Globcover ESA database[50] these strict constraints resulted in 560 km^2 of usable area. The open-field potential is mostly limited by the restriction of using land currently used for agriculture. The available areas are mostly situated in the southwestern part of Ukraine, as depicted in Figure 3.12, the total sums can be found in Figure 3.14. Based on the available area of 560 km^2 it is estimated that 9700 MW$_p$ of installed open field PV capacity can be installed.

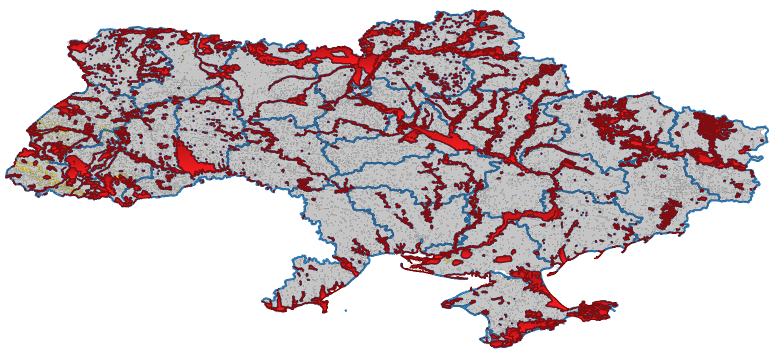


Figure 3.12: Suitable areas for open-field PV (yellow), reds are environmentally protected areas, greys excluded areas due to their current use, or slope. Open-field PV potential is very limited by the restriction on using agricultural land. Open-field PV availability is most densely concentrated in the southwestern part of Ukraine.

Next to the open field potential, the rooftop potential is analysed. Since no comparative research could be found, the rooftop potential is also analysed based on geospatial analyses. The first step is to determine the total urban area in Ukraine, again using the Globcover ESA database[50]. The second step is to determine the suitable rooftop ratio as well as their orientations and incline. Here this report deviates from the Eurocalliope method because the assumptions in that research are based on Swiss data [51]. Similar data for Ukraine is unavailable, therefore a method based on the description of Mainzer *et al.* [52] is used. They estimated the PV rooftop potential in a few German cities based on open-source data. For this paper, 1 square kilometre of the city of Kyiv is analysed using OpenStreetMap data [53]. OpenStreetMap reports for a select number of houses the shape and orientation of the rooftop, Figure 3.13 shows the sample density of the building data. It shows that the results from this analysis are based on a small sample size, with limited data availability. However, from this data, the ratio of flat to inclined roofs is determined, as well as fractions of northern-southern and east-west facing buildings. The results are assumed to be applicable to all urban areas in Ukraine and extrapolated to all urban areas. Data on urban areas per region in Ukraine is retrieved from the Globcover database [50]. The combination of these two data sources resulted in a total PV rooftop potential of 79 GW_p. The shares per orientation are listed below.

- Available area per squared kilometre of urban built-up area: 0.2 km^2
- Flat: 36%
- Inclined south facing: 17.4%
- Inclined east facing: 13.8%
- Inclined west facing: 14.5%
- Inclined north facing: 18.0%

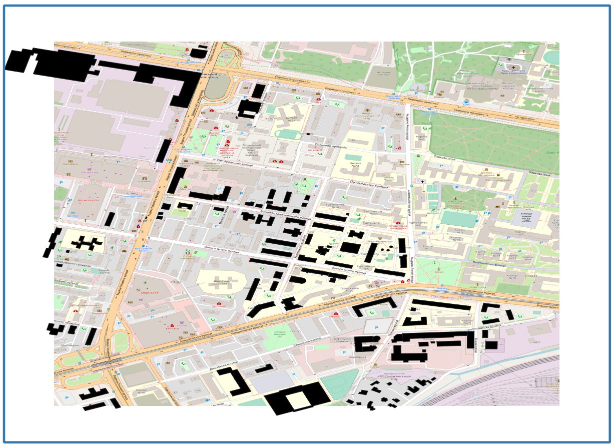


Figure 3.13: Part of the analysed region of Kyiv, black boxes are building with complete rooftop data [53]. Depicts the limited amount of available data to estimate the rooftop potential in Ukraine

For a complete estimation of potential capacity, the potential yield of each region is also analysed. Based on the ERA-5 [36] data, the average yearly global horizontal (GHI), direct normal (DNI) and diffuse horizontal irradiance (DHI) between 1950 and 2020 are evaluated. The results for GHI are depicted in Figure 3.14. This figure highlights two things, first regions surrounding the black sea offer the highest yields. Unfortunately, these are not the regions with the most available area. These regions have a high share of agricultural land use, which for economic and ethical reasons are not considered eligible for PV installations. Second, there exists a fairly large decline in irradiance between the south and north of Ukraine. This results in more economically favourable conditions in the south in comparison to the northern regions, while the north-western regions are more densely populated.

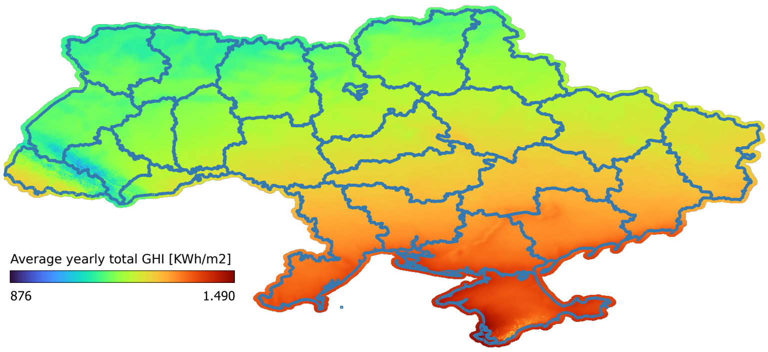


Figure 3.14: Yearly average Global Horizontal Irradiance in Ukraine between 1950 and 2020 [36]. Regions surrounding the Black Sea offer the best yields. The figure also shows a large decline in irradiance between the south and north of Ukraine

The combined analysis of the literature and geospatial analysis of open field and rooftop PV resulted in the following PV potentials (Figure 3.15). In general, the total PV potential from the geospatial analysis is 5 GW higher than the value obtained from the literature. The rooftop potential is much larger than the open field potential despite lower yield in the northern regions. Also, the open field capacity has the additional downside to have to compete with onshore wind capacity for land use. Despite these findings, the lower costs and more favourable orientations of open-field PV could still make it a valuable RES asset for Ukraine.

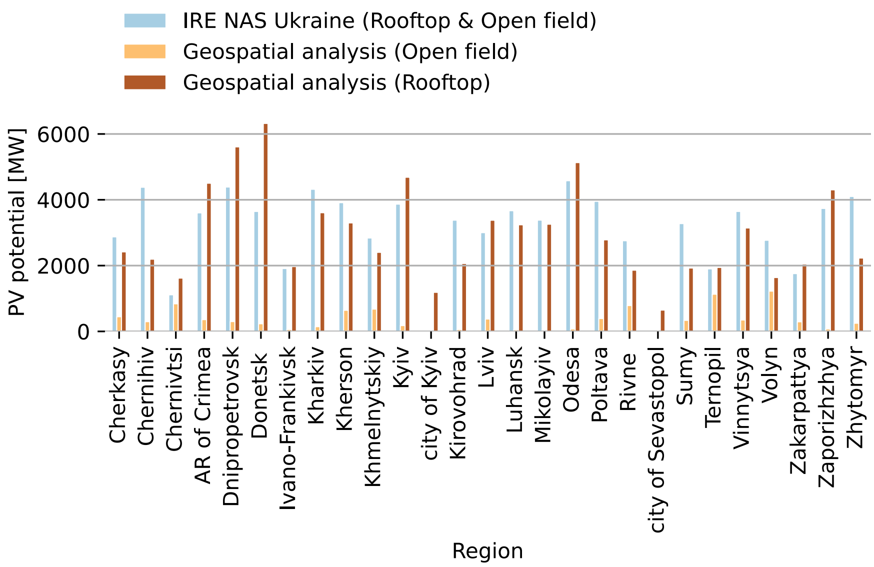


Figure 3.15: PV potential per region from IRE NAS [49] and geospatial analysis. The rooftop potential far exceeds the open-field potential in every region. Overall both geospatial analyses show comparable results to the literature.

Capacity factors

The capacity factors for both deployments, orientations and inclines are retrieved from renewables-ninja and produced by Pfenninger and Staffell [54]. The authors used MERRA and MERRA-2 meteorological data to compute hourly time series with capacity factors across Europe. To allow for bias removal these values should be reanalysed using actual capacity data from PV systems in Ukraine. Since no such data could be retrieved the values are used as obtained. To account for regional differences, a 50-squared kilometre grid has been drawn over Ukraine, and the time series capacity factor has been retrieved for each centroid. The capacity factor time series for each region is the mean of all the time series of each centroid within this region.

3.6.2. Wind power

Wind power is the second renewable energy source considered in this chapter. Extended research on wind energy capacity in Ukraine has been done by various authors and institutions. The results between sources vary, depending on the method and assumptions used. For example, IRE NAS evaluated the onshore and offshore wind potential in 2020, by evaluating the local geographics and combining this with long-term wind speed observation data [55]. Makarovskiy and Zinych [56] also used a geographical approach but combined it with windpower density calculations. This resulted in similar or higher potentials. More recently Antoniuk *et al.* [57] researched how wind energy in Ukraine is currently operating and its prospects for recovery after the conflict. Based on the current practices concerning building wind farms in Ukraine, they evaluated the capacity potential of wind energy for all regions in Ukraine. Lastly, for consistency with the Euro-Calliope optimizations from Pickering *et al.* [32], geospatial data from the Globcover database [50] is analysed with 10-arcsecond resolution. Only suitable areas are considered for onshore wind farms, such as farmlands, open vegetation and bare lands. With the exclusion of environmentally protected or built-up areas. Figure 3.16 shows the resulting suitable areas for onshore wind.

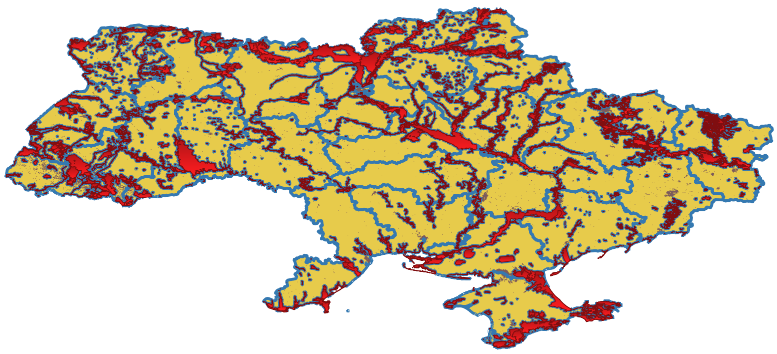


Figure 3.16: Available areas for onshore wind (yellow), reds environmentally protected areas, and black unavailable zones due to their current use. In total 440 GW of onshore wind capacity is available, uniformly distributed in Ukraine.

To translate available areas into capacities, the assumption is made that the capacity density is 8 W/m^2 for onshore wind [32]. Next to onshore wind, offshore wind capacities are also estimated. Due to a lack of knowledge on offshore site requirements, these are purely based on literature findings from [55]–[57]. The overall resulting capacities are depicted in Figure 3.17. The total potential for onshore wind is 440 GW, and for offshore 140 GW. This is in compliance with [49], [55], [56]. Antoniuk *et al.* [57] estimated lower potentials of around 290 GW, and therefore deviates from the other three sources.

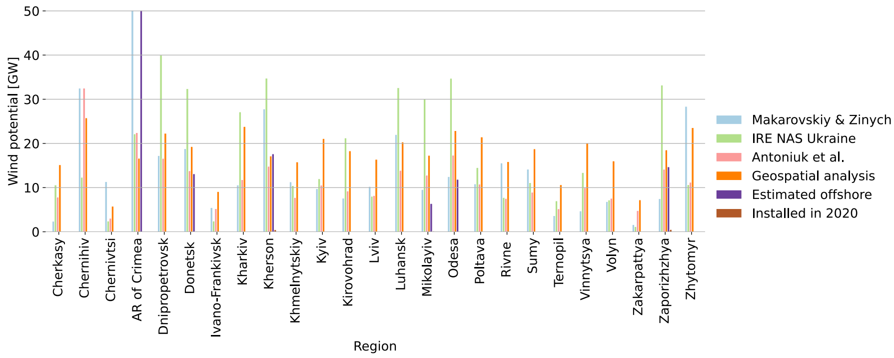


Figure 3.17: Wind potential and installed capacity from various sources per region in GW [49], [56]–[58]. There exist large differences in the literature between estimated wind power capacities in Ukraine. The figure also shows that currently only a limited amount of wind power is installed, leaving room for large expansion.

When the potentials from Figure 3.17 are compared to the current installed capacity in 2020 it shows enormous room for growth. In 2020 only 1.3 GW of wind capacity was installed, in 31 farms ranging from 200 to 2 MW sizes [58]. Not surprisingly these are centred around the high windpower density regions along the Black and Azov Sea, Figure 3.18. When the installed capacity between 2014 and 2020 is compared, it's interesting to point out that no new farms have been built in the border regions. Despite lower capacity factors in Lviv, Odesa and Zaporizhzhia these locations have been favoured over Crimea and Luhansk. With only Donetsk being the exception, with an increase of 300 MW between 2014 and 2015 [58].

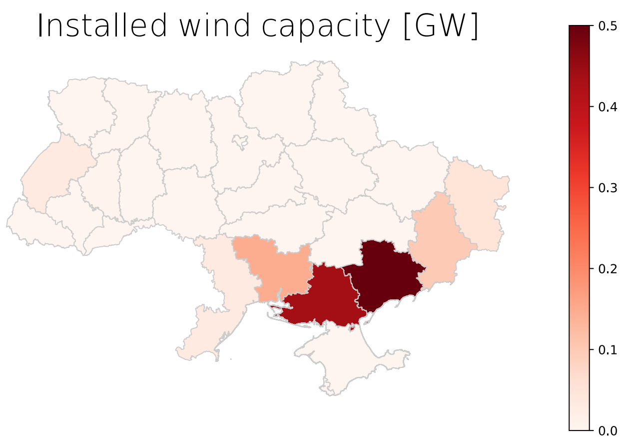


Figure 3.18: Installed onshore wind power plants per Oblast in GW (no data for Crimea) [58]

Capacity factors

To model the seasonal and weather-dependent variability of wind energy, time series with capacity factors are used as input for the optimization. Actual time series from wind farms in Ukraine are unavailable, therefore estimations need to be used. In this paper, we use the Renewable-ninjas website [38] for three reasons. Mainly because the authors published capacity factors time series and underlying wind speed data, for all of Europe, and for different types of turbines. Also for consistency with the Euro-Calliope optimization and for the possibility to use the 2018 underlying data in correspondence with the other inputs. Additionally, the underlying paper describes the method to remove bias from the output, increasing the reliability of the optimization.

As described by Staffell and Pfenninger, these capacity factors are computed using satellite data from the Merra and Merra-2 databases. They showed that the data needs to be corrected from bias. This can be done for the entirety of Ukraine on a national level based on known yearly capacity factors from existing wind power plants. This method requires knowledge of the location of the wind parks, the capacity factor on a yearly basis and the type of windmill used.
The wind speed(w) retrieved from the data must be corrected from bias to determine the corrected windspeed (w') using the linear correction:

$$w' = \alpha w + \beta \tag{3.1}$$

Whereas α can be computed as a function of the systematic error (ϵ_{CF}). ϵ_{CF} is itself the ratio between the observed actual capacity factor and the simulated capacity factor from renewable-ninja:

$$\epsilon_{CF} = \frac{CF_{obs}}{CF_{sim}} \tag{3.2}$$

$$\alpha = 0.6\epsilon_{CF} + 0.2 \tag{3.3}$$

The observed capacity factor is retrieved from [58], this report contains a detailed list of installed capacity, containing locations and windmill types. It also contains capacity factor data from the years 2015 to 2020. Making it one of the most detailed sources of wind capacity factors in Ukraine. The simulated capacity factor is retrieved from the renewables-ninja website.
After establishing ϵ_{CF} and α, β can be computed using numerical methods. The goal is to find β such that the newly simulated capacity factors are equal to the observed capacity factors. β is determined for all of Ukraine by evaluating the Botievska and Orlivska wind power parks (wPP) in Zaporizhzhia and the Myrneska WPP in Kherson. These have been selected on the basis of the availability of yearly capacity factor, and the availability of turbine type in renewable ninjas. Also, both sites and wind turbine types represent roughly 25% of the total installed capacity and 63% of types of turbines [58]. Fitting the data to match the true capacity factors resulted in the following two values; for $\alpha = 0.52$ and $\beta = 2.932\ m/s$. These values are comparable with the computed values from other European countries in the supplementary information of [38]. Now all wind speed data from the renewables-ninja can be adjusted for bias using Equation 3.1, and translated into capacity factors by interpolation of the power curves.

To summarize, for each 50 km by 50 km grid, wind speed data has been retrieved from renewable-ninja. For the specified WPP locations also capacity factor data was retrieved. Based on observed and simulated capacity factors, bias correction factors are computed. These factors are used to modify the retrieved wind speed factors to bias-corrected capacity factors. Lastly, the capacity factors per region are the average of the grid points they contain.

3.6.3. Hydropower

Hydropower is an especially interesting renewable energy technology because of its unique feature to also store energy. The deployment differs from wind and solar power on one main aspect, hydropower is far less variable, making it a unique, and essential technology for the energy transition. In this research, three different kinds of hydropower plants are considered, run-of-river hydropower plants (RoR), reservoir and pumped storage hydropower plants (PSHPP). This section describes the potential for hydropower per region, and the method to determine the capacity factor time series.

The potential for hydropower in Ukraine is determined by literature research. Unfortunately, data on total hydropower potential is limited, and data on regional potential is even more limited. The IRE NAS reported RoR potentials, but not the method or the source [49]. Stefanyshyn [59], reports the current installed RoR capacities and the PSHPP potentials. He also researched the current efficiency and deployment of hydropower in Ukraine and highlights unusually low efficiencies and capacity factors when compared to other countries. They are the result of outdated designs and economic inefficiencies in the energy market [59]. Kurbatova [60] reports for RoR hydropower the unexploited capacity, the total, technical and economical potentials for each region but in yearly yields rather than installation capacity. By combining the capacity factors from [59] with the yields of [60], the yields are transferred into potential capacities and compared to the other findings. The results are displayed in Figure 3.19, and the derived values from Kurbatova are for many regions in line with the other two sources. For unknown reasons, the estimates for Volyn, Dnipropetrovsk, Lviv, Mykolayiv Chernivtsi and Crimea are considerably higher. The potential of the run of river hydropower is set as the average between the three sources and for the above-mentioned regions as the average of the first 2 sources.

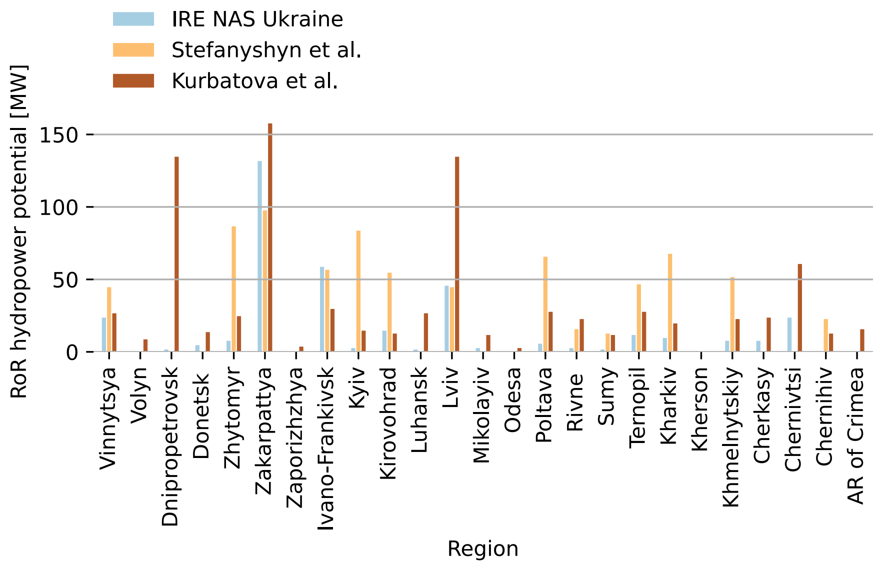


Figure 3.19: Run of river hydropower potential per Oblast in MW [49], [59], [60]

The reservoir and PSHPP capacities are assumed to be equal to the currently installed capacity, depicted in Table 3.1. Since expanding or building new capacity takes decades, overreaching the 2030 goals. It's worth noting that this assumption is debated by the IEA [2] which recommends the expansion of hydropower in the Dnieper and Dniester rivers by updating the current turbines. It also recommends the modernisation of 5900 MW of existing RoR currently operated by UkrHydroEnergo, to increase the efficiency and capacity. This should be taken into account for future longer-term forecasts.

Table 3.1: Installed Reservoir and PSHPP capacities in 2019 [59]

Oblast	Reservoir [MW]	Reservoir [MWh]	PSHPP [MW]	PSHPP [MWh]
Dnipropetrovsk	352	35200	0	0
Zaporizhzhya	1569	156900	0	0
Kyiv	408.5	40850	235	352
Kirovohrad	632.9	63290	0	0
Mikolayiv	0	0	302	172
Kherson	351	35100	0	0
Cherkasy	444	44400	1000	2508
Chernivtsi	142	14200	972	2043

Capacity factors

Unfortunately, neither the JRC-IDEES [32] nor the ENTSO-E [34] contains historical time series about generation outputs. Nor could any other source provide these values. Therefore capacity factor time series are based on the same approach as wind and are calculated for RoR and PSHPP. Here this paper again deviated from the Euro-calliope method that retrieved time series from JRC-IDEES. Rather than using wind speed as a proxy, river discharge is used, retrieved from the Copernicus database [61]. Using the same 50 km^2 gridpoints, the average release for each region can be calculated for 2018, and for the 2010-2020 decade. The discharge time series are converted to RoR capacity factors using the assumption that the installed RoR operates at maximum efficiency around the decade-average discharge.

For PSHPP capacity factors are less dependent on river discharge, economics and regulations play a much larger role. These factors are not simulated inside the Calliope framework. Therefore general capacity factors are assumed based on the river discharge data, with the additional assumption that for low discharge values, $\leq$10% of the multiyear average, the capacity factor is equal to zero, resembling drought conditions.

3.6.4. Biomass

The fourth RES that is being considered is biomass. Biomass, unlike solar and wind, is not a variable power source, making it an excellent renewable option for peak moments. Besides generating electricity it is often also used for (district) heating. Biomass also suffers from a few downsides, it is often quite expensive compared to other renewable sources such as solar and wind power, and fossil sources such as coal and nuclear. Burning biomass still leads to air pollution although it is considered to be almost carbon neutral. The biggest controversy is land competition, by growing crops to be specifically used as a biomass source rather than food crops [62].

The biomass potential of each region is reported by the EU, which researched the possibility of Ukraine becoming a biomass exporter to meet EU demand for energy. They have selected the most promising agricultural residues, namely, wheat, sunflower husk and forest residues. By selecting only residue streams, an effort is made to make estimations based on sustainable biomass. Residue streams are considered sustainable because they don't require land replacement competition with food crops, which has negative ethical aspects. Also, they excluded the biomass needed to prevent erosion and maintain soil organic matter. For this optimization, forest residue is excluded, since according to the report there is currently no infrastructure in place to gather and process this resource [63], making it the most unlikely source to be used by 2030.
Transporting biomass is very inefficient due to the low energy density. The abundance of agricultural activity throughout Ukraine allows for waste streams to be used locally [44] (agricultural activity is depicted in Figure 3.2). Thus it is assumed that biomass does not need to be transported across regions. With the exception of the two city regions Kyiv and Sevastopol, they have access to 20% of the potential of their surrounding region. This results in the following resource potentials, depicted in Figure 3.20. The total amount of energy available from biomass is 165 TJ, making it a promising resource to increase autarky. Yet the low efficiency of biomass CHP plants, 19% and relatively high costs put this number in perspective.

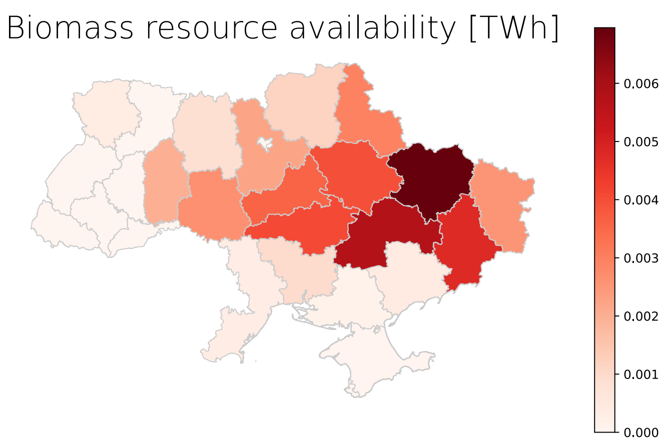


Figure 3.20: Regional biomass potential [62]. This only includes sustainable biomass sources. There is an abundance of biomass in Ukraine, but there is currently no infrastructure available to process this into a suitable energy source.

3.7. Simulation settings

After determining the required inputs for the Calliope model in the previous sections. This section describes how the simulations are configured. It starts by describing the main constraints in the basic model and explains why the basic model had to be spatially constrained. Finally, it will explain the goal of each simulation and any additional settings that had to be implemented.

3.7.1. Basic model

The basic model is as unconstrained as possible to find the most general possible solutions. This section describes the main adaptations to the Euro-Calliope model and the main constraints. The basic model includes all ENTSO-E countries on a national level, meaning they each consist of a single region, equal to the Euro-Calliope national model [32]. Additionally to this setup, Ukraine is added on a regional scale as described in section 3.1 Belarus, Russia and Moldova are added as nodes with distinct electricity demand, as described in section 3.5.

The considered technologies are all those included in the Euro-Calliope optimization, required to supply, store or consume, electricity or heat. All costs, efficiencies, and lifetime assumptions are equal except for rooftop and open-field PV. The capital expense (CapEx) and operational expenses (OpEx) costs for the PV technologies are compared to the values used by the papers evaluating the Ukrainian energy system. Diachuk, Chepeliev, Podolets, *et al.* [5] based their CapEx estimation for PV rooftop and open-field on Child, Breyer, Bogdanov, *et al.* [6], and industrial consultancy. The former also reported OpEx costs for both systems. Saha, Mettenheim, Meissner, *et al.* [12], does not specify the difference between rooftop or open-field PV, and based their cost estimates on numbers posted by the European Commission's Joint Research Centre. The cost estimations for Euro-Calliope [32] are based on those from the Danish Energy Agency [64]. All cost assumptions are summarized in Table 3.2. Based on their relative differences and publication dates, the rooftop PV cost assumptions from Euro-Calliope are applicable to Ukraine. Open-field PV CapEx costs are lowered to 1300 €/kW and the OpEx costs are raised to 14 €/kW/year, to better correspond to the main literature findings.

Table 3.2: Summary of different PV cost assumptions

	Rooftop		Open-field	
Author	Capex [€/kW]	Opex [€/kW/year]	Capex	Opex
Diachuk, *et al.* [5]	1700	-	1300	-
Child,*et al.* [6]	1360	20	1000	15
Saha, *et al.* [12]	674	10	674	10
Danish Energy Agency [64]	1670	16.7	1550	13.6
Thesis:	1670	16.7	1300	14

Lastly, the significant current electricity and heating generation capacities are either set as upper limits or frozen at their current power levels. Upper limits are set for the current coal (CHP) plants, CCGT and nuclear power plants, to allow for results with decreased capacities. while the major hydropower and storage facilities are frozen at their current levels. As they are a renewable energy source but unlikely to increase by 2030.

Testing of this model revealed that it requires long computation times. To reduce these computations times, and increase the number of iterations that can be done, the spatial resolution is reduced. The following section describes how and why this does not affect the end results significantly.

3.7.2. Restricting the spatial scale

As described in subsection 2.1.2 and 2.1.3, including surrounding nations in the optimization results in more realistic models and solutions. This comes at increased computational time and resource usage. To determine the difference between the three different geographical models, as depicted in Figure 3.21, the cost-optimal solution of each geographical model is compared on the KPIs from section 2.3 and the total system costs. Euro-Calliope includes all ENTSO-E countries and Ukraine [32], Eastern-EU contains Ukraine with surrounding countries, and UA only encompasses the Ukrainian regions.

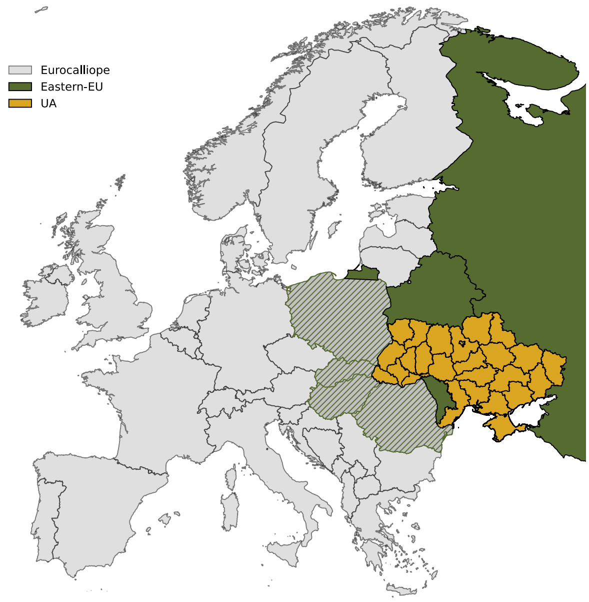


Figure 3.21: Geographical visualizations of the different spatial models. Ukraine is always modelled on a regional scale. the surrounding ENSTO-E members on a national scale, and the surrounding non-ENTSO-E members as nodes, with a specific electricity demand profile.

The results, as depicted in Figure 3.22 show that the KPIs computed from the cost-optimal solutions are comparable. Each value is within 10% for each KPI. This leads to the conclusion, that the impact of decreasing the geographical scale to Eastern-EU is limited, and a good alternative to either computing the entire ENTSO-E region or Ukraine as an island. Eastern-EU still takes cross-border effects into account and saves computation time. Therefore all the computations are done using this geographical scale.

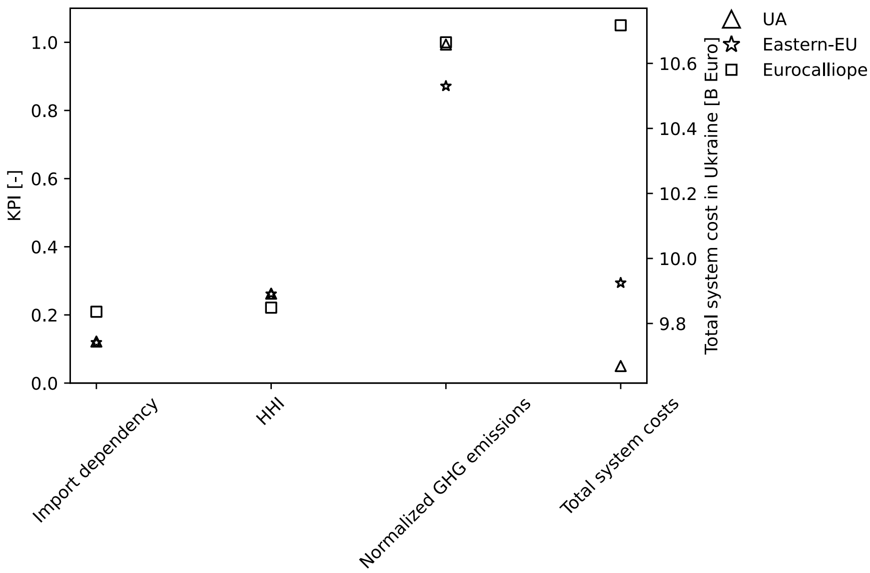


Figure 3.22: Comparison of the cost-optimal solutions for different geographical scales. The results indicate that restricting the model to the East-EU configuration has a limited impact on the KPIs. The total system cost on the right y-axis only contain the cost associated to technologies inside Ukraine

3.7.3. Influence of maximizing PV deployment strategies on the KPI

The goal of the first simulation is to see how the KPIs change for each deployment strategy and explore any difference between deployment strategies. This is done by forcing Calliope to find solutions in which certain PV technologies are maximized. Three different deployment strategies are determined based on the technological and economic differences in Calliope. They are named rooftop PV, open-field PV and the combined strategy, referring to the PV technology that is being maximized. First, we allow Calliope to determine the cost-optimal solution and then request six times for 20 sub-optimal solutions, using the spores method. The spores method is used to compute these solutions and to also create spatially diverse solutions. The solutions are constricted by a slack-costs constraint. This means that the sub-optimal solutions cannot be more than 10% more expensive than the cost-optimal solution. These slack costs are applied to the entire system. To prevent the spores method from also maximising specific PV technologies outside of Ukraine, the three PV technologies are defined specifically for Ukraine, ergo they have a unique name. Intermediate results showed that the 10% slack costs constraints were not loose enough to find solutions meeting all GHG emission and KPI targets. This led to the expansion of the first simulation to include a 50% slack cost constraint. Table 3.3 shows the six different combinations of spores constraints and spores settings.

Table 3.3: Overview of the six spore sets and constraints combinations.

Maximization of:	Slack-cost constraint:	
rooftop PV	10%	50%
open-field PV	10%	50%
rooftop and open-field PV	10%	50%

3.7.4. Effects of minor increments PV technologies on the Ukrainian energy system configuration

The spores method quickly reaches the maximal deployment potential for both open-field and rooftop PV. It does not correctly show the effects of limited installed PV capacities on the KPIs. Also, in the spores method, PV rooftop and open-field PV are not mutually exclusive. Results computed from spores containing both types of PV are therefore hard to assign to a specific deployment strategy. Another downside of the spores method is that it starts searching for alternatives from a cost-optimal solution, which does not necessarily represent the current situation.

To overcome these downfalls, and show the impact of smaller PV capacities, a second simulation is conducted. This simulation uses the same Eastern-EU spatial model and the same constraints as described in the basic model. This model differs from the model in Simulation I on a few items. First, to be able to achieve results better representing the current situation in Ukraine, an additional limit is set for GHG emissions. They should be less or equal to 160 $MtCO_{2eq}$, the 2020 GHG emissions from the electricity and heat sector, depicted in Figure 2.1. To enforce solutions with increasing amounts of PV capacities, the model contains an additional carrier production inequality constraint. Lastly, to be able to make sure any changes in the KPIs are either caused by rooftop, open-field or a combination of both, the model increasing rooftop PV does not include open-field PV and the model increasing open-field PV does not include rooftop PV. The model increasing both is not subjected to this constraint.
This model is run 30 times, 10 times for each deployment strategy. Each of these 10 runs searches for the cost-optimal solution subjected to a unique inequality constraint. The carrier production inequality constraint forces the solution to supply all electricity demand in Ukraine by a specific group of technologies. The technologies comply with the PV deployment strategies, either rooftop, open-field or both. The scenarios increasing open-field PV (11 -20) are subjected to a less or equal constraint "carrier_prod_max" and the rooftop scenarios (1-10) to an equal or bigger constraint "carrier_prod_min". The scenarios depicting the combined growth (23-30) are subjected to both, depending on the increment. This difference in the type of inequality constraint is necessary since the cost-optimal result from this model without any inequality constraints already contains 2.5 GW of open-field PV. If the open-field PV deployment increments would be subjected to the equal or bigger constraint it would result in 10 equal solutions. The same goes for the combined strategy for the first 3 increments.

For each deployment strategy, the fraction increases linearly to 5, 15, or 20% for the open-field, rooftop and combined strategies. These limits are based on the intermediate 2030 results from Diachuk *et al.* [5]. Table 3.4 depicts an overview of the scenarios and constraint settings.

Table 3.4: Overview of the 30 scenarios and their carrier_prod constraint.

Constrain rooftop PV		Constrain open-field PV		Constrain all PV	
Scenario	**Carrier_prod_ setting:**	**Scenario**	**Carrier_prod_ setting:**	**Scenario**	**Carrier_prod_ setting:**
1	≥ 1,5%	11	≤ 0,5%	21	≤ 2%
2	≥ 3%	12	≤ 1%	22	≤ 4%
3	≥ 4,5%	13	≤ 1,5%	23	≥ 6%
4	≥ 6%	14	≤ 2%	24	≥ 8%
5	≥ 7,5%	15	≤ 2,5%	25	≥ 10%
6	≥ 9%	16	≤ 3%	26	≥ 12%
7	≥ 10,5%	17	≤ 3,5%	27	≥ 14%
8	≥ 12%	18	≤ 4%	28	≥ 16%
9	≥ 13,5%	19	≤ 4,5%	29	≥ 18%
10	≥ 15%	20	≤ 5%	30	≥ 20%

4

Results

This chapter presents the results from the first and second simulation. Section 4.1 starts by showing the KPI scores of all sub-optimal solutions produced by the first simulation. It will then show and describe in more detail how the different deployment strategies impacted the three KPIs, import ratio, HHI and GHG emissions. Section 4.2 presents the results from the second simulation which show how smaller increments affect the KPIs. It presents how the generation composition changes, and plots the different KPIs versus the installed PV capacities.

4.1. Results obtained by maximising the PV deployments

Figure 4.1 summarizes all the solutions obtained using the spores method in three KPIs. The six possible combinations of constraints and deployment strategies can be distinguished by the colours and marker style combinations. The Figure also includes the cost-optimal solution as a reference for the starting point of the spores method.

As a reminder, the import ratio takes the consumption of electricity, coal, biomass and methane into account. These values are combined with the predicted consumption outside of the heat and electricity sector. Total consumption is divided by the current production of Ukraine to compute the import ratio. The import ratio KPI scores range between 50 and 35%. Coal consumption and electricity imports are the most significant contributors to this KPI results. The upper boundary of 50% is marked by the cost-optimal solution, which deploys the largest share of coal-fired power plants. The data indicate that solutions maximizing open-field combined with 10% cost slack, have almost no impact on the imports. Increasing the cost slack to 50% for all deployment strategies leads to lower import ratios. Another remarkable feature is that the solutions reach a lower boundary at 35%. At this point lowering fossil fuel consumption results in increased electricity imports, creating a balance.

The HHI, measuring the diversity is the second KPI. The HHI displayed in this figure is the mean, of the regional HHI. Near zero score imply perfect diversity, and near one implies a monopoly. Figure 4.1 shows that the effect on the HHI index is uniform for each PV deployment strategy and constraint combination. Overall the open-field deployment strategy has the largest effect on this KPI. With the 10% cost slack constraint, the spores already result in HHI indices of 0.24. Lower HHI scores can be reached by increasing the cost slack, but gains are only marginal. This is to be expected since the HHI is asymptotically going to zero. Also deploying large shares of PV does not increase the HHI. This indicates that it never replaces all other technologies.

The GHG emissions depicted in Figure 4.1 are affected differently by open-field PV deployment as opposed to rooftop or the combined deployment. Because the maximum open-field potential is low compared to rooftop PV, it reveals a remarkable phenomenon. Solutions maximizing open-field PV have relatively high GHG emissions. Optimizing the open-field PV leads to phasing out nuclear power. This has the negative side effect that more electricity and heat needs to be produced by fossil-fueled technologies. At higher installed open-field capacities, this negative effect is mitigated. The solutions of combined and rooftop deployment strategies deploy such high amounts of PV that the initial negative effect is not visible in this figure.

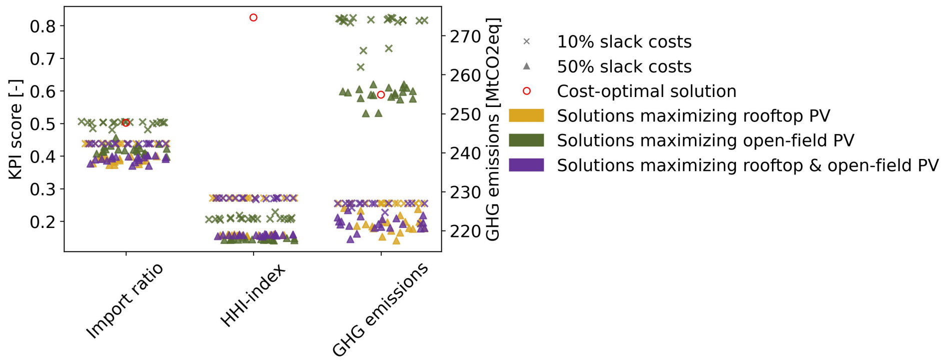


Figure 4.1: Summary of all solutions from the first simulation. The import ratio includes consumption outside of the heat and electricity sector, it takes electricity, coal, methane and biofuels into account. The HHI-index plotted in this graph is the average HHI of each region, near 0 means perfect diversity, and 1 implies a total dependency on a single technology. GHG emissions take only the emissions from the electricity and heat sector into account. The results show that there is only limited diversity between the individual results per maximization spore set. However, it indicates a maximal reduction of the import ratio from 0.5 to 0.36. Increase in diversity from 0.6 to a maximum of 0.15. The data indicated that GHG emission reductions can increase by maximizing open-field PV, and will decrease if the other deployment technologies are maximized.

4.1.1. The general trends

Figure 4.3, 4.5 and 4.4 provide a more detailed look into the individual results. Each figure contains the results of one KPI. The subfigures are formatted in a matrix-like style where each row represents a PV deployment strategy and each column a set of constraints. Due to the simulation setup, the results are less diverse than expected. Still, the experiment shows a few results worth mentioning.

There are a few general trends. Most notable is the similarity between the rooftop and combined spore sets for both sets of constraints. This is due to large differences between the total capacity potentials of rooftop and open-field PV. The rooftop PV completely overshadows the effects caused by open-field PV in the combined strategy, resulting in comparable solutions for the rooftop and combined deployment strategies.

In each graph, the cost-optimal solution is highlighted by a red circle. This solution shows the starting point for each optimization. It is interesting to see that the cost-optimal spore does not deploy any rooftop PV but does almost maximize the open-field potential. The solutions maximizing the rooftop PV capacities show that open-field PV becomes redundant at high installed rooftop PV capacities. In contrast, solutions maximizing the open-field PV deployment do still include rooftop PV, although at much lower capacities (± 7 GW for 10% cost slack, and ± 25 GW for 50% cost slack). However, utilizing both PV technologies does not translate into lower GHG emissions or import dependency scores but does increase diversity.

With increased slack costs, the composition of the spores becomes more diverse, but the KPIs remain rather constant. The 10% cost slack and 50% costs slack mainly differ on the required transmission and storage capacities. The 10% cost slack solutions already require relatively large transmission capacities. To be specific, the spores with the 10% cost slack constraint all require roughly 200 GW of transport power. This is a 250% increase compared to the 75 GW currently available [48]. Due to disparities between the regions, open-field PV is differently distributed than rooftop PV in Ukraine. This explains the slightly different transmission capacity requirements.

Figure 4.2 shows the domestic average transportation capacity requirements per region. For simplicity, the rooftop and combined strategy are plotted as a single purple bar. It shows that all deployment strategies require roughly the same amount of transport capacity, but regional differences exist. The largest differences occur in Chernivtsi (CV), Ivano-Frankivsk (IF) and Zakarpattya (ZK), all located in southeast Ukraine.

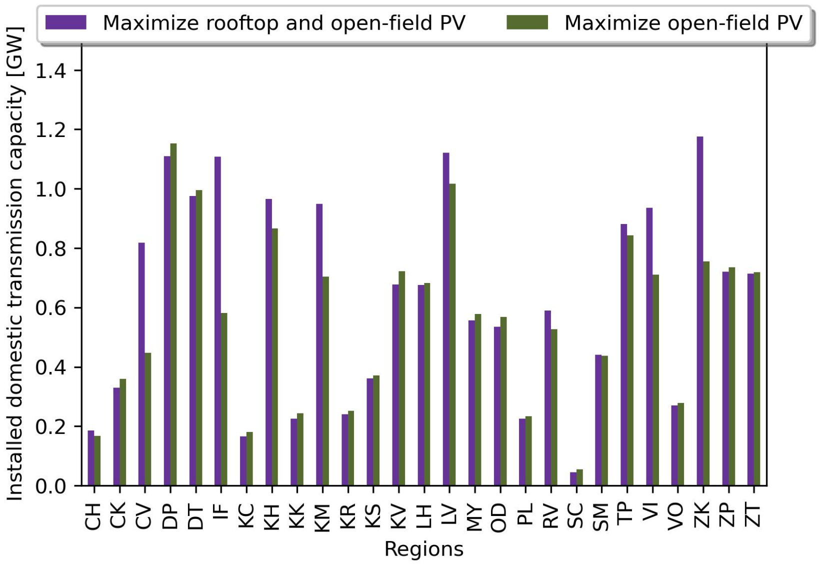


Figure 4.2: The bars represent the average transmission capacity required for each deployment strategy under the 10% cost slack constraint. Due to similarities between the rooftop PV and combined strategy, they are both represented in the purple bars. It shows that all deployment strategies require roughly the same amount of transport capacity, but regional differences exist. A full list of regional abbreviations can be found in the appendix

The electricity sector in Ukraine already utilizes large hydro storage facilities with large potential capacities. The data does not show any deployment strategies that include large investments in battery storage. Allowing for a 50% cost increase, results in roughly 10 GWh of battery storage, marginal compared to the 400 Gwh of pumped hydro storage already available. The optimization rather increases the heat storage capacities, allowing for electrification of the heat sector.

4.1.2. The rooftop and combined PV strategy

The top two rows of Figure 4.3 display how the import ratio is affected by the rooftop and combined strategy. The solutions contain around 79 GW of rooftop PV more, as compared to the cost-optimal solution which contains almost no rooftop PV. Rooftop PV has the ability to decrease the import ratio from 0.5 to 0.44. Applying the 50% cost-slack constraint results in import dependencies of around 0.38. This reduction is facilitated by increased transmission capacities and heat storage facilities. Lastly, the larger cost constraint allows for solutions containing wind capacity, and reducing the capacity of fossil-fueled CHP plants.

The influence regarding the HHI index is displayed in Figure 4.4. The cost-optimal solution has an HHI of 0.8 mostly relying on coal (CHP) plants. The combined and rooftop strategy deploys 79 GW of rooftop PV gradually over all the regions, resulting in an HHI of 0.3. Allowing for the 50% cost increase reduces the HHI to 0.2. These solutions contain additional wind and CCGT power, which allows for an even more diverse electricity and heat sector.

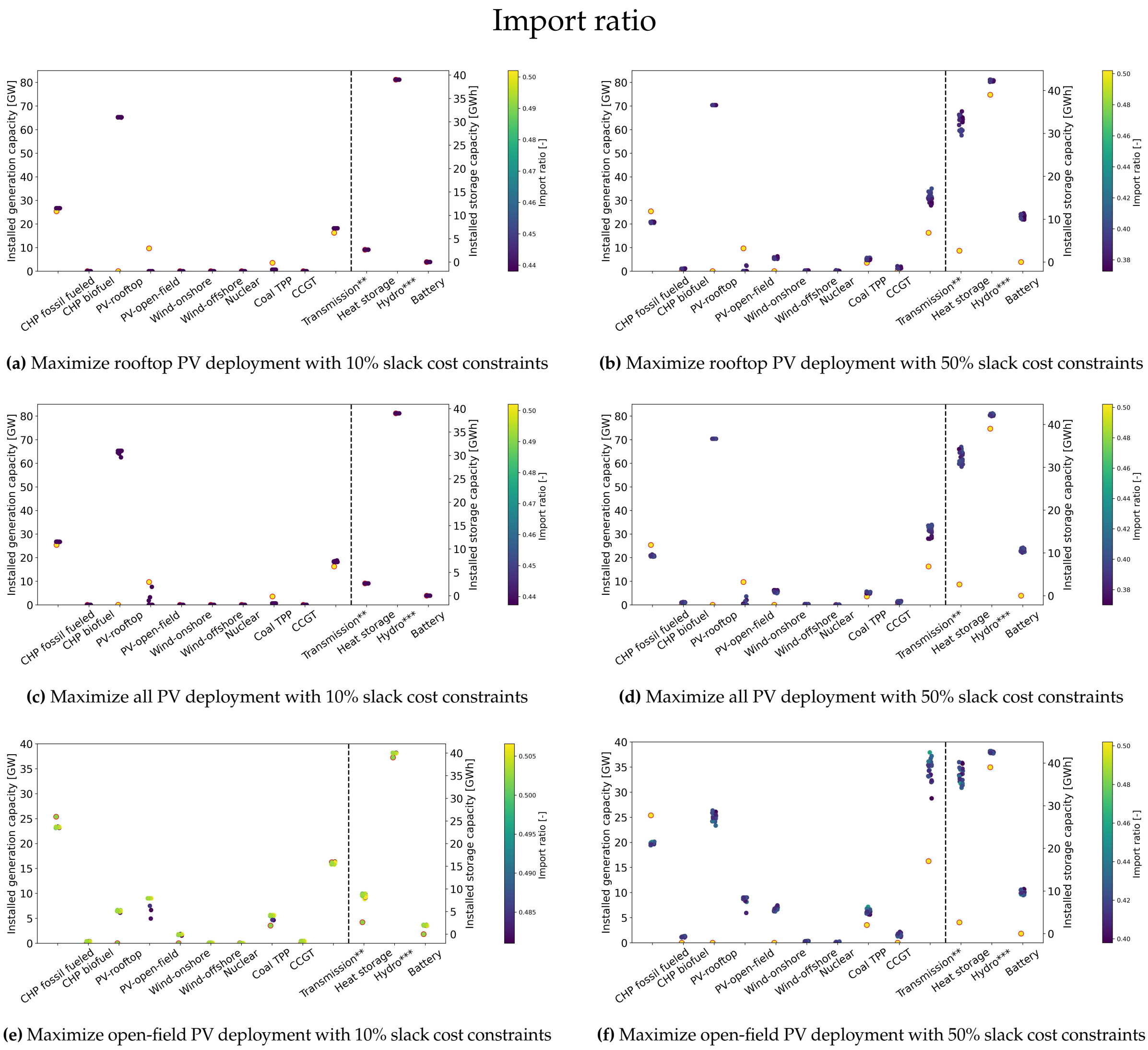
The impact of rooftop and combined strategy on GHG-emission is depicted in Figure 4.5. Maximizing while allowing for a 10% cost increase leads to ± 10% reduction in GHG emissions. The data indicate that maximizing rooftop PV or all PV capacities require additional coal (CHP) plant capacities. The overall decrease in GHG emissions does indicate that they have lower capacity factors as compared to the cost-optimal solution, thus reducing the overall consumption of coal. Solutions allowing for 50% cost increases do not results in additional GHG emission reductions.

4.1.3. The open-field PV strategy

The bottom row of Figure 4.3 displays how the import ratio is affected by the open-field PV strategy. Compared to the cost-optimal solution, the import ratio decreases from 0.5 to 0.48. This decrease is minor compared to the rooftop and combined strategy. Maximizing open-field PV often results in increased coal power plant capacities. Which leads to increased coal imports. Applying the 50% slack cost constraint reduces the import ratio to 0.38. These solutions deploy more wind, transmission capacity and heat storage, which allows for a relatively large reduction of fossil-fueled CHP plants. Which results in lower coal imports.

Second, the influence of open-field PV on the HHI is depicted in Figure 4.4. The low availability of open-field PV results in a natural diversity in the generation composition. Solutions with strict cost constraints of 10% already achieve good HHI scores. Increasing the costs slack to 50% allows the diversity to increase up to 0.2. As mentioned before, solutions contain relatively large wind and heat storage capacities. Introducing these technologies to the electricity and heat sector leads to additional diversity.

Figure 4.5 also displays different solutions maximizing the open-field PV and their relation to the GHG emissions. The cost-optimal solution already contains the maximum amount of open-field PV. The sub-optimal solutions slightly increase GHG emissions due to an increased dependency on fossil-fueled CHP plants. Allowing for a 50% cost increase reduces the GHG emission by 4% compared to the cost-optimal solution. The data indicates that this is again facilitated by increasing wind power, and transmission capacities and adding additional heat storage facilities.



(a) Maximize rooftop PV deployment with 10% slack cost constraints

(b) Maximize rooftop PV deployment with 50% slack cost constraints

(c) Maximize all PV deployment with 10% slack cost constraints

(d) Maximize all PV deployment with 50% slack cost constraints

(e) Maximize open-field PV deployment with 10% slack cost constraints

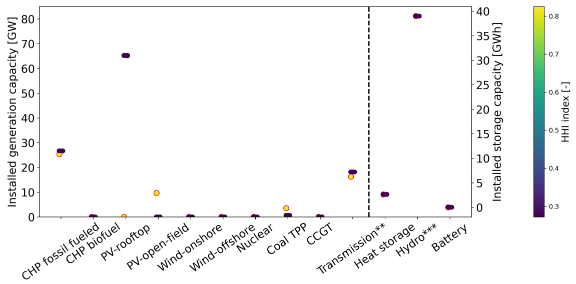
(f) Maximize open-field PV deployment with 50% slack cost constraints

Figure 4.3: Overview of the generation and storage capacities of each solution and their effects on the import ratio

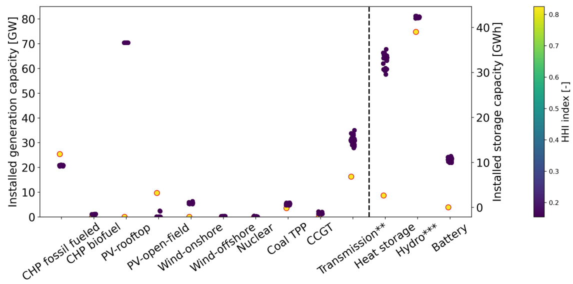
*The circled red dot depicts the cost-optimal solution. **Transmission capacity is depicted using a different scale [1/10 GW], *** Hydro capacity is depicted using a different scale [1/10 GWh].

The data show considerable overlap between the results maximizing rooftop and the combined PV deployment strategies and limited diversity between solutions. Maximizing rooftop PV leads in general to increased capacity requirements for coal-powered technologies, but these have lower capacity factors. This can decrease the import ratio from 0.5 to 0.44. Applying the 50% cost-slack constraint to the spores maximising rooftop or all PV results in import dependencies of around 0.38. This reduction is facilitated by increased transmission capacities and heat storage facilities. Maximizing the open-field PV has a more limited impact on the import ratio, it reduces this KPI from 0.5 to 0.48. Applying the 50% slack cost constraint can reduce the import ratio to 0.38. These solutions deploy more wind, transmission capacity and heat storage and decrease the fossil-fueled CHP capacity.

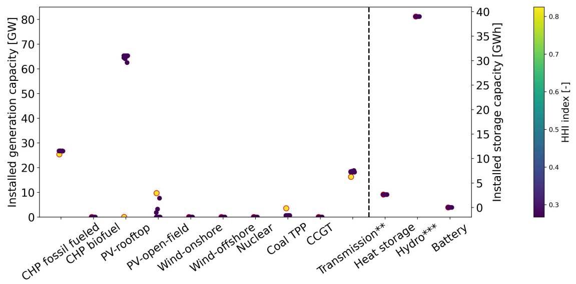
HHI-index



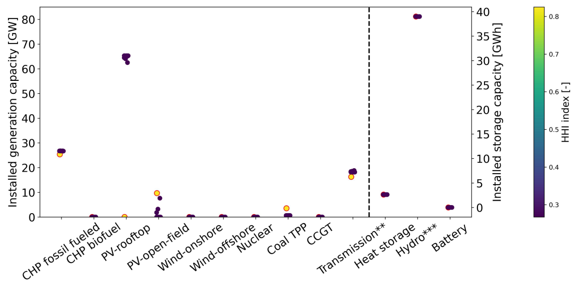
(a) Maximize rooftop PV deployment with 10% slack cost constraints



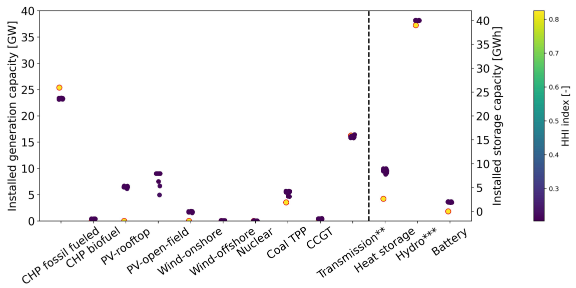
(b) Maximize rooftop PV deployment with 50% slack cost constraints



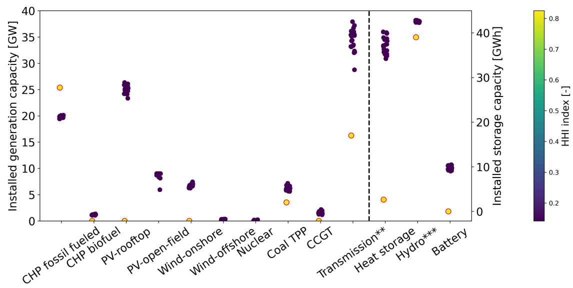
(c) Maximize all PV deployment with 10% slack cost constraints



(d) Maximize all PV deployment with 50% slack cost constraints



(e) Maximize open-field PV deployment with 10% slack cost constraints



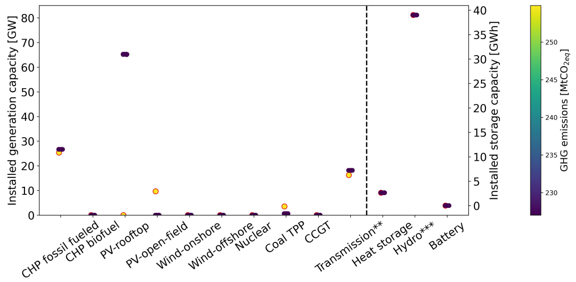
(f) Maximize open-field PV deployment with 50% slack cost constraints

Figure 4.4: Overview of the generation and storage capacities of each solution and their effects on the HHI

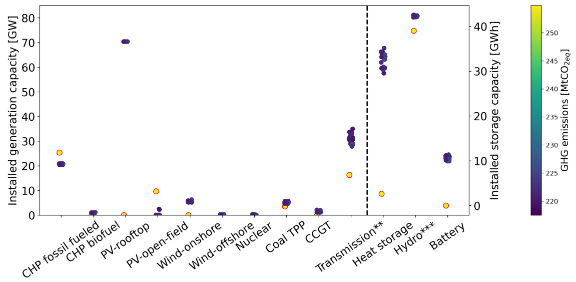
*The circled red dot depicts the cost-optimal solution. **Transmission capacity is depicted using a different scale [1/10 GW], *** Hydro capacity is depicted using a different scale [1/10 GWh].

Maximizing the combined PV and rooftop PV results in an HHI of 0.3. The 79 GW of rooftop PV is gradually deployed over all regions, which diversifies each regional electricity and heat sector. Allowing for the 50% cost increase can reduce the HHI to 0.2. This allows for diversification by increasing the wind and CCGT capacities. The low potential of open-field PV results in a natural diversity in the generation composition. Optimization with strict cost constraints of 10% results in very low HHI scores. Allowing for larger cost constraints results in only marginal increases in the HHI.

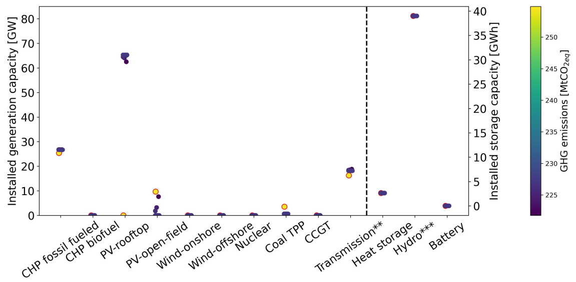
GHG emissions



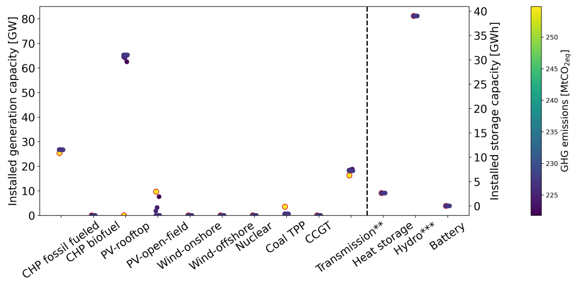
(a) Maximize rooftop PV deployment with 10% slack cost constraints



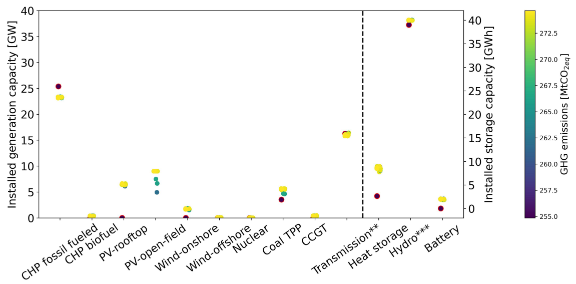
(b) Maximize rooftop PV deployment with 50% slack cost constraints



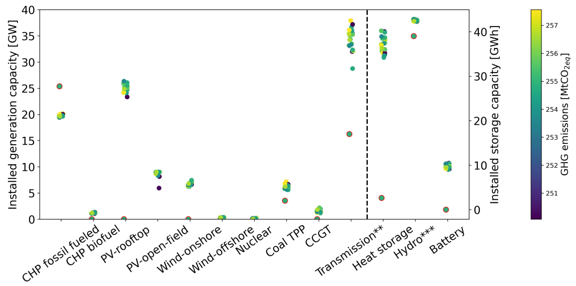
(c) Maximize all PV deployment with 10% slack cost constraints



(d) Maximize all PV deployment with 50% slack cost constraints



(e) Maximize open-field PV deployment with 10% slack cost constraints



(f) Maximize open-field PV deployment with 50% slack cost constraints

Figure 4.5: Overview of the generation and storage capacities of each solution and their effects on the GHG emissions

*The circled red dot depicts the cost-optimal solution. **Transmission capacity is depicted using a different scale [1/10 GW], *** Hydro capacity is depicted using a different scale [1/10 GWh].

Optimizing the rooftop PV or all PV with allowing a 10% costs increase leads to ± 10% reduction in GHG emissions. The data shows that this requires small increases in coal (CHP) plants, but they have lower capacity factors compared to the cost-optimal solution, reducing the overall consumption of coal. The solutions maximizing open-field PV slightly increase GHG emissions due to an increased dependency on fossil-fueled CHP plants. Allowing for 50% cost prevents this negative effect by including larger wind and rooftop PV capacities.

4.1.4. Comparison of the solutions with the current Ukrainian electricity sector

The spores method explores the effect of maximizing different PV technologies in Ukraine. The low diversity between sets of constraints and spores allows for a general comparison to the current installed capacities, as depicted in Figure 4.6. This Figure shows the average installed generation capacity for each set of spores and constraints together with the cost-optimal solution and the current installed capacities obtained from [2], [10], [34].

As described in section 2.5 the current Ukrainian energy system is inefficient and outdated and it was designed for a much larger economy. This is still visible in the current installed capacity of around 80 GW, as this is twice as large as the total capacity required for the cost-optimal solution. The current electricity sector also contains practically no variable renewable energy sources, such as wind and PV. The literature reviews from section 3.6 showed that only 1.3 GW of onshore wind, 0.5 GW of rooftop PV and 2 GW of open-field PV are currently installed in Ukraine.
The solutions maximizing PV technologies add large amounts of variable RES to the sectors. This requires storage and dispatchable generation capacity as well as cross-border flows to match supply and demand. Regardless of the spores set or constraints, the results show that roughly 27 GW of dispatchable power is required in Ukraine to support large shares of PV. This dispatchable capacity is composed of around 22 GW of CHP and 5 GW of hydro. According to the model this is the most economical option to achieve the required dispatchable capacity. These dispatchable assets are already available in Ukraine. It contains 35 GW of CCGT, 5 GW of coal-fired TPP, 20 GW of CHP plants, 5 GW of hydro and 14 GW of nuclear power. However the results from the previous sections showed that the CHP plants are mainly fueled by coal, which results in relatively high GHG emissions. To diminish GHG emissions, phasing out coal in favour of gas or nuclear-powered plants might be beneficial. Although each of these options comes with increased dependencies on Russia for fuels. Especially the current dependency on Russian nuclear fuel refineries could be an argument to opt for coal over nuclear-fueled dispatchable capacities .

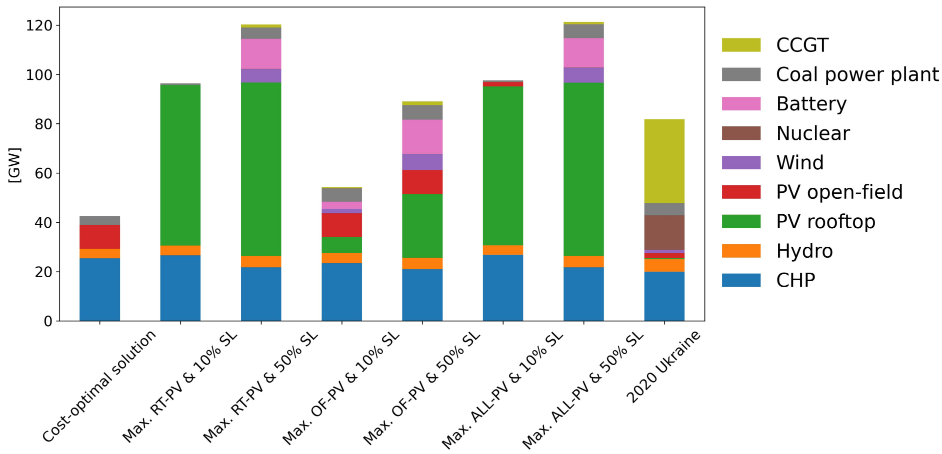


Figure 4.6: The average composition of the spores, grouped by spores sets and slack cost constraint (SL). It also depicts the composition of the cost-optimal solution and that of the 2020 Ukrainian electricity sector [2], [10], [34]. This graph shows that roughly 30 GW of dispatchable power is required to support the large shares of variable renewable energy sources. These are currently available in Ukraine and depending on economic or political reasons can be used to supply Ukraine with dispatchable power in 2030.

Bridging the gap between supply and demand caused by implementing large shares of variable renewable power can also be done by increasing the cross-border flow. Figure 4.7 depicts for each set of spores and constraints the average electricity production per source, including the electricity transported to the surrounding ENTSO-E members. Only the surrounding ENTSO-E countries are being considered in this graph because electricity imports from Moldova, Belarus and Russia are not considered in this model, as described in subsection 3.1.3. The results indicate that maximizing PV in Ukraine results in exports of electricity. The amount of exported electricity on a yearly basis depends on the amount of installed PV. The solutions maximizing rooftop or all PV export almost 50 TWH of electricity, equal to one-third of the Ukrainian 2030 electricity demand. Increasing the cost slack to 50% allows for installing

around 10 GW of battery output power. This should increase the self-consumption of electricity in Ukraine. The solutions containing additional battery storage do not show a decline in yearly electricity exports. This is unexpected behaviour for which currently no explanation can be found.
Taking a closer look at the cross-border flows per hour (Figure 4.8), puts the overall exports in perspective. The data indicate that maximizing PV results in large fluctuations between imports and exports on a daily basis. This indicates that maximizing PV does not result in autarky, Ukraine remains dependent on neighbouring countries. Both graphs also depict a clear seasonal trend of importing during the winter and exporting during the summer. This is to be expected when only PV is being maximized. The bottom graph depicts the solutions permitting 50% cost increases. These time series show a smaller difference between the average winter imports and summer exports, indicating that the additional battery storage helps to buffer the difference between supply and demand.

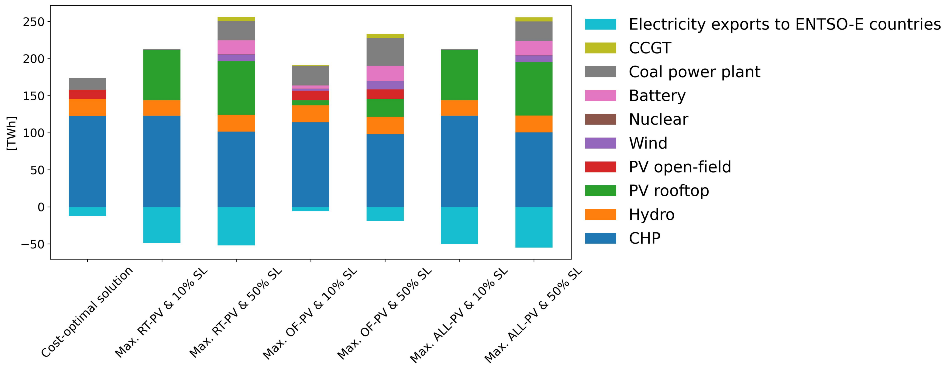


Figure 4.7: For each set of spores and constraints the average electricity production per source, including the electricity transported to the surrounding ENTSO-E members is depicted. This shows that Ukraine is a net exporter of electricity. Increasing the share of PV in the sectors leads to an increase in net exports. Adding additional storage capacities does not result in a decline in electricity exports

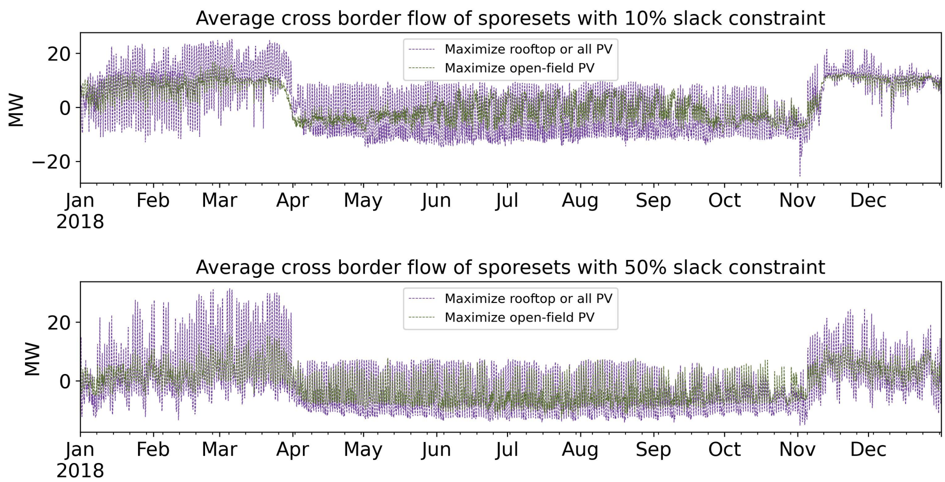


Figure 4.8: The cross-border flows per hour puts the overall exports in perspective. The data indicate that maximizing PV results in large fluctuations between imports and exports on a daily basis. It also reveals the seasonal pattern.

4.2. Results obtained by incrementally increasing the PV deployments

Simulation I showed how the KPIs are affected by the maximization of the different PV capacities. The resolution of solutions containing low amounts of PV is limited. A second simulation is conducted to get a more in-depth understanding of how smaller PV capacities impact the KPIs. It shows a trajectory towards meeting 20% of electricity demand with PV by 2030 [2]. First, the implications on the generation capacities are shown, followed by the impacts on the KPIs.

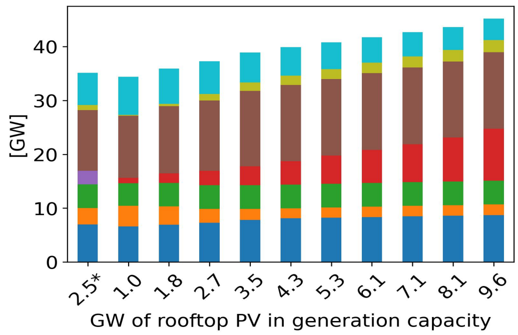
4.2.1. Installed capacities

The resulting required capacities and shares of electricity supply for each PV deployment strategy are depicted in Figure 4.9. Each graph shows the universal cost-optimal solution first and the incremental solutions in increasing order. The left column presents the installed capacities, and the right column the percentage of electricity supplied by the PV technology. The first row depicts scenarios 1-10, with increasing rooftop PV. The second row depicts scenarios 21-30 with increasing rooftop and open-field PV. The third row depicts the results from scenarios 11-20, with increasing open-field PV. The labels on the x-axis show the installed considered PV technology installed, or the market share of electricity production achieved.

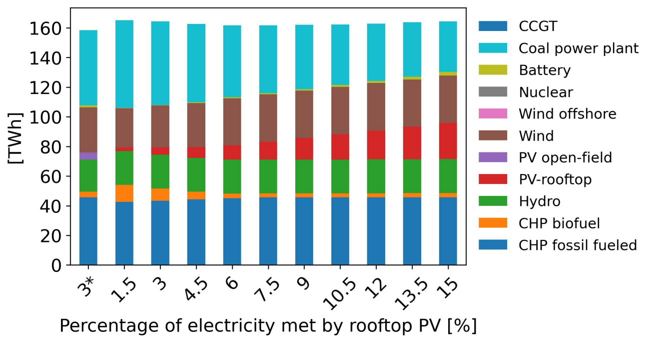
One major difference with the first simulation is the diversity of generation capacity. This is more in compliance with the current installed capacities as described in section 2.5. It is still not a perfect representation since nuclear and wind capacities are not comparable to the current installed capacities. The solutions could be forced to mimic the current situation by adding more constraints, but this leaves less room for optimization. The choice is made to continue with the current settings due to time constraints and not overconstraining the model.

The different strategies show a few common trends. The data in Figure 4.9 shows that increasing PV capacities lead to increased battery storage requirements, due to the mismatch between supply and demand, regardless of the considered PV technology. The trends also show that increasing PV leads to reductions in coal power plant capacities and electricity outputs. But the dependency on CHP plants remains high, partly caused by the heat demand in Ukraine. The data indicates that it is more economical to reduce biomass-fueled CHP plants rather than fossil-fueled CHP plants. Reducing the GHG emission reduction potentials for PV in the model.

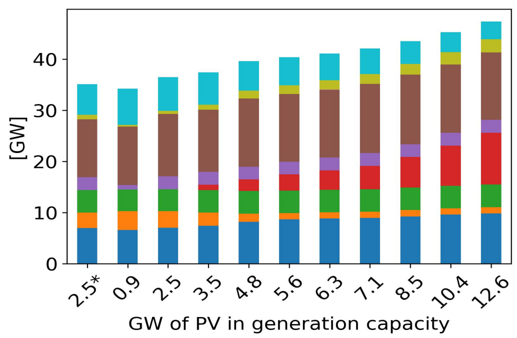
Subfigures 4.9a, 4.9b, 4.9c and 4.9d again show many similarities between the rooftop and combined deployment strategy. The main difference is that the last two, depicting the combined strategy, show that rooftop and open-field PV can co-exist. This contradicts the results from the first simulation, where the combined strategy reduces the open-field PV capacities in favour of rooftop PV.
The last row shows the effect of incremental increasing the open-field capacity, Figure 4.9e and 4.9f. The limited availability of open-field PV leads to smaller changes compared to the unconstrained solution. The bar plots show that this trajectory is of extra importance. Because the unconstrained solution also contains 2.5 GW of open-field PV, implying good costs efficacy of open-field PV.



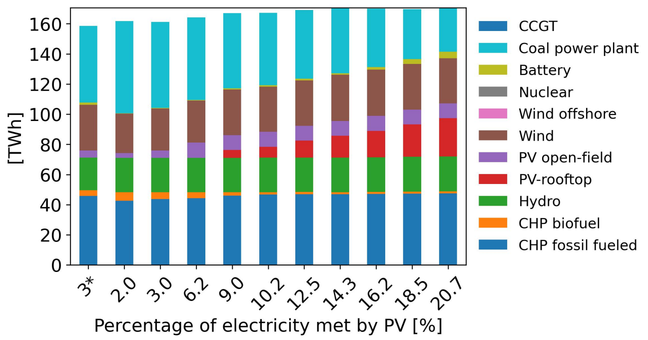
(a) Generation capacities per technology group subject to PV rooftop constraints



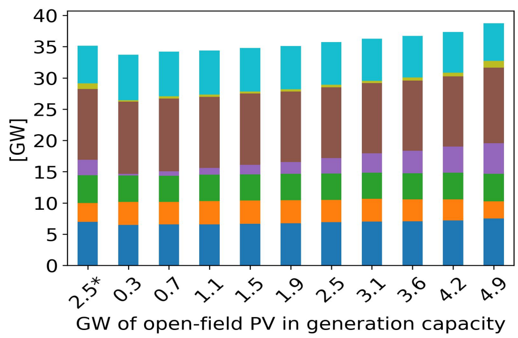
(b) Shares of electricity production per technology group subject to PV rooftop constraints



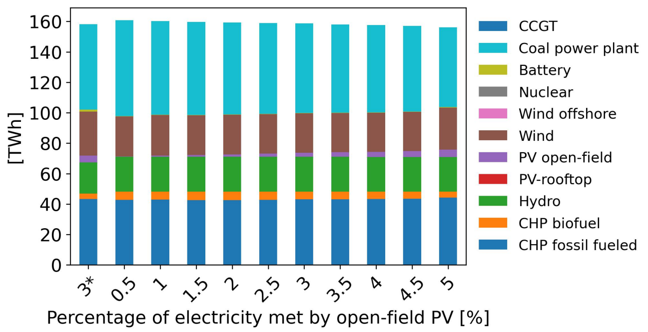
(c) Generation capacities per technology group subject to open-field & rooftop constraints



(d) Shares of electricity production per technology group subject to rooftop & open-field constraints



(e) Generation capacities per technology group subject to PV open-field constraints



(f) Shares of electricity production per technology group subject to PV rooftop constraints

Figure 4.9: Generation capacities and electricity production per PV deployment strategy

* This is the cost-optimal solution not subjected to any carrier_prod constraint.

The left column displays the generation capacities of each scenario, and the right column the market share of electricity production for each scenario. From top to bottom, the first row depicts results with constraint rooftop PV, the middle all PV and the bottom the open-field PV. The results are more in compliance with the current Ukrainian energy system as compared to the first simulation. The dependency on coal for each scenario remains high. The data shows that the power output of coal-fired plants remains almost constant, but the capacity factors decrease significantly. Increasing the PV share of supplied electricity requires increased battery storage capacities, this is most notable in the combined strategy results, in the second row.

4.2.2. Effects on the KPIs

This simulation allows for a more detailed look into the effects of the deployment strategies on the KPIs. Figure 4.10, 4.12 and 4.11 each show the KPIs and cost comparison for each strategy and increment.

The import ratio in Figure 4.10 shows an overall linear downward trend for each strategy. The data indicated that this is the result of phasing out coal-consuming technologies. This effect is similar for each deployment strategy. The Figure also shows that at low capacities, the results constraining rooftop PV have a negative impact on the import ratio compared to the cost-optimal solution. This is caused by the higher dependency on biomass as shown in Figure 4.9a. A cost comparison between the open-field, rooftop PV and combined strategy shows that the latter is the most cost-effective to decrease the import ratio. The threshold of 0.36 from the first simulation is not reached by this simulation, indicating that electricity imports do not yet govern the import ratio.

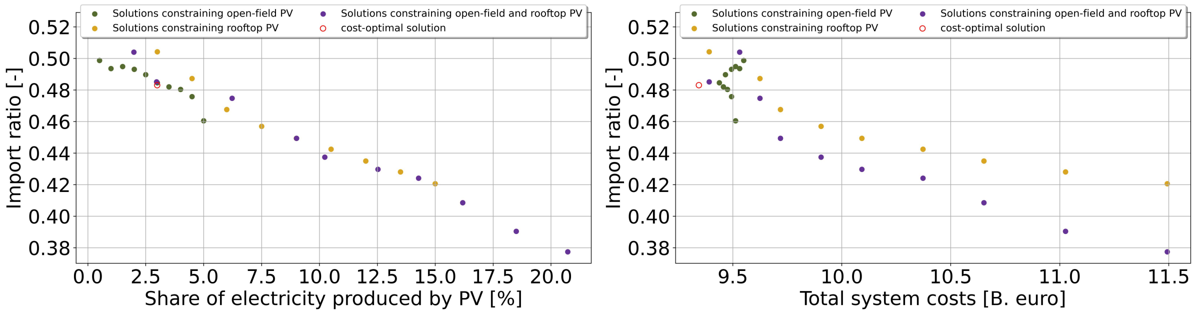


Figure 4.10: on the left: The overall impact of deployment strategies on the import ratio. Each deployment strategy has the same impact up until 20% market share. The threshold of 0.36 from the first simulation is not reached by this simulation. On the right: Cost-effectiveness of each strategy for reducing the import ratio. The combined strategy is more cost-effective in reducing the import ratio compared to the rooftop PV deployment strategy. At low capacities, open-field PV is the most cost-effective but has only limited potential.

GHG emission reductions also show a linear negative trend for each deployment strategy, as depicted in Figure 4.11. The effect of each deployment strategy is almost equal. The data indicates that the rooftop PV deployment strategy is slightly more effective in reducing GHG emissions as compared to the combined strategy. Again caused by the slightly higher use of biomass to produce electricity and heat. The combined strategy is overall more cost-effective than the rooftop PV strategy. Mainly caused by the share of less expensive open-field PV, and reduced transmission requirements.

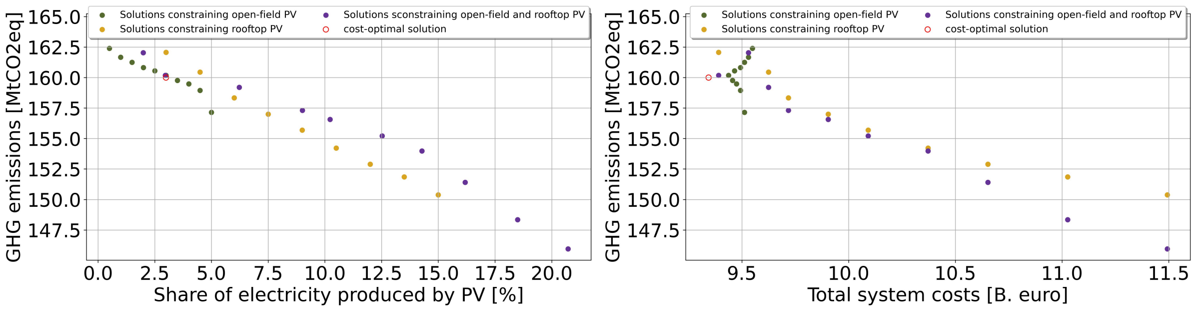


Figure 4.11: On the left: Overall impact of deployment strategies on the GHG emissions. Each deployment strategy has a linear effect on the GHG-emissions. The effect of open-field PV remains limited due to its low potential. On the right: The cost-effectiveness of each strategy for reducing GHG emissions. The combined strategy is overall more cost-effective than the rooftop PV strategy. Mainly caused by the share of less expensive open-field PV, and reduced transmission requirements.

The effect on the HHI is depicted in Figure 4.12. The main takeaway is that increasing the open-field capacities has a limited impact on diversity. Opposed to the results from the first simulation the open-field PV deployment strategy now shows no impact on the HHI. This can be explained by the few locations suitable for open-field PV, resulting in a very regional impact on the HHI. The method of computing the HHI also plays a role. The HHI reported is the average HHI of each region. This explains why the local effect of implementing open-field PV is mitigated by the unaffected regions. The data also indicates that the rooftop PV has a stronger effect on the HHI than the combined strategy. The cost comparison shows that the combined and rooftop deployment strategy are equally cost-effective.

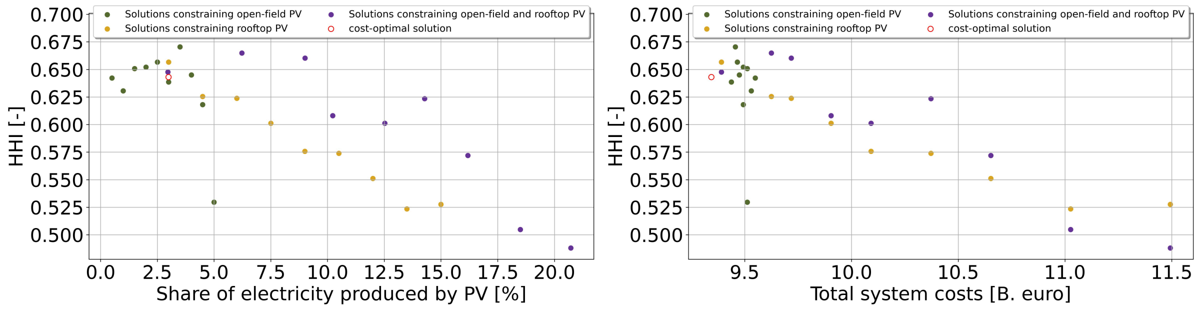


Figure 4.12: On the left: Overall impact of deployment strategies on the HHI. The data indicates that the open-field deployment strategy has a negligible impact on the KPI. This can partly be explained by the regional potential of open-field PV and the method of computing the KPI. On the right: The cost-effectiveness of each strategy for increasing diversity. Both the rooftop and combined strategy are equally cost-effective in reducing the HHI.

4.2.3. Spatial diversity

Because of the diversity between open-field PV, rooftop PV and the combined PV strategies, regional differences can also be explored. Figure 4.13 shows the relative deployment of each PV strategy per region. Relative means the ratio between the installed capacity, and potential capacity per considered technology per region. Figure 4.13 clearly shows that the results do not predict a feasible pathway for deploying PV. For example, while increasing the share of electricity produced by rooftop PV from 1,5% to 6%. The solutions would deploy 0%, 30%, 30% and 0% in Chernihiv (CH) consecutively. The exact reason for this behaviour can currently not be explained. Therefore the data should be used to interpret the general trends between the deployment strategies, not as a pathway description to reach a certain market share of PV. The data indicates that rooftop deployment favours the Dnipropetrovsk (DP), the city of Kyiv (KC), Kharkiv (KK), Poltava (PL) and Sumy (SM) regions. While open-field could better be concentrated in Chernihiv (CH), Kyiv Oblast (KV), and Volyn (VO).

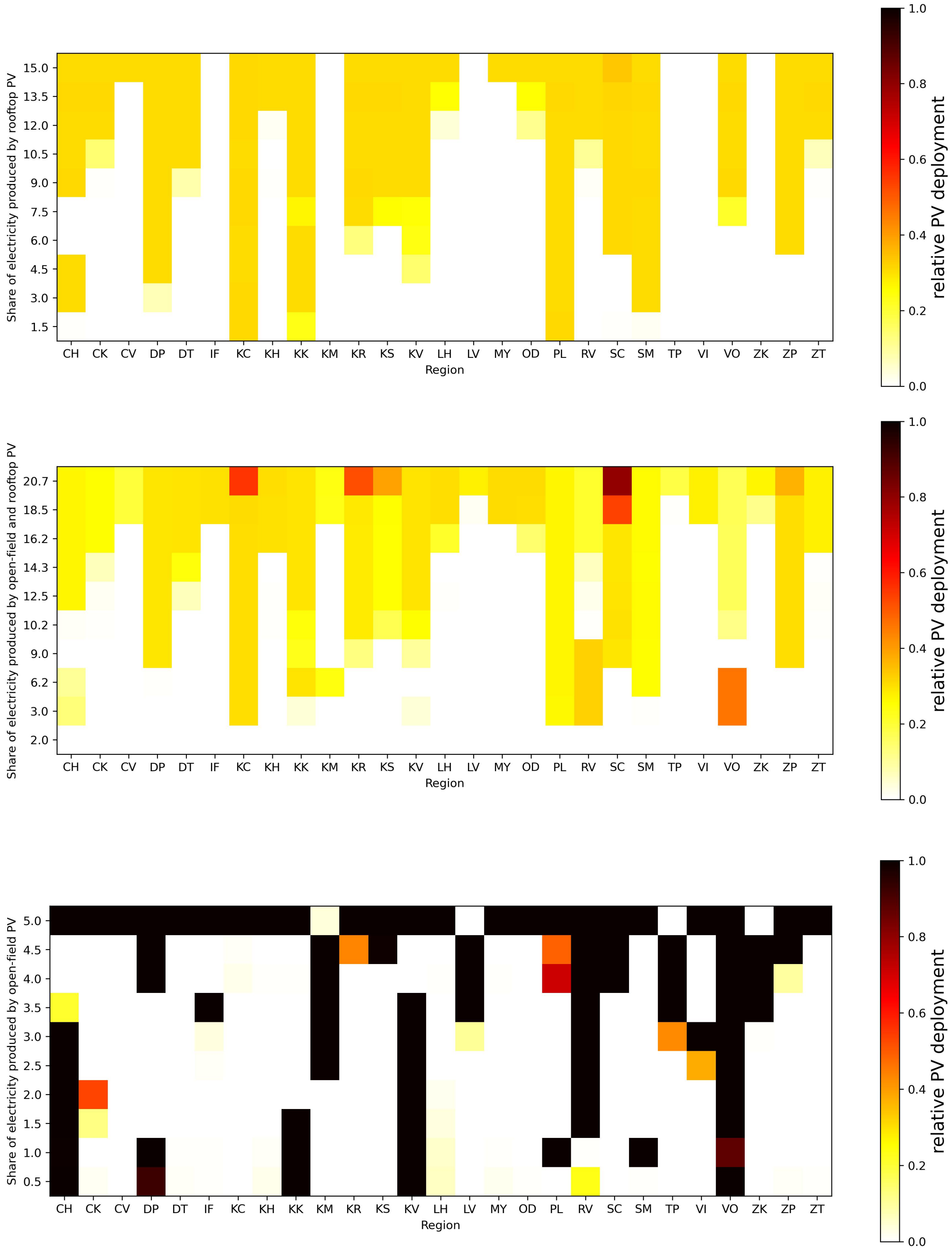


Figure 4.13: Heat map showing the relative deployment of the considered PV technologies per deployment strategy. Upper left: rooftop PV, upper right: combined PV, lower left: open-field PV. It shows that rooftop deployment favours the Dnipropetrovsk (DP), the city of Kyiv (KC), Kharkiv (KK), Poltava (PL) and Sumy (SM) regions. While open-field could better be concentrated in Chernihiv (CH), Kyiv Oblast (KV), and Volyn (VO). The data cannot be used as a pathway to reaching a certain degree of PV penetration. A full list of regional abbreviations can be found in the appendix

5
Discussion

This chapter discusses the results of this thesis. First, it evaluates the effects of the deployment strategies on each KPI by comparing the results to the literature. Second, is followed by some general trends found in the results from both simulations. After this, the chapter highlights the key limitations of this master's thesis.

5.1. Assessing the effects of PV deployment strategies on the KPIs with literature

Both simulations conducted in this study showed that introducing any form of photovoltaic deployment strategy always leads to better performances on import ratio, GHG emission reductions and HHI key performance indicator scores. This general finding is consistent with the literature that addresses energy security, such as [6], [5], and [12]. These studies confirm the data indicating that renewable energy sources (RES) lead to increased energy security.

A more specific look at the KPIs shows that each deployment strategy has the same effect on the import ratio. The cost comparison analysis between the results from the second simulation indicates that the combined strategy is the most cost-efficient. The data also indicates that the import dependencies can be reduced from around 70% in 2020 to 36% in 2030 by introducing PV. However, the lower limit around 36% seen in this paper is not observable in the literature. The revolutionary scenario from Diachuk reports an import ratio of 10% by 2050 [5], while Child reports no imports by 2050 in the power sector [6]. In contrast to this study, both authors consider Ukraine as an island. They do not include energy trade between countries and do not take imported electricity into account. This shows the importance of a clear definition of how import dependency is defined. Differences in assumptions can lead to very different solutions.

The results from the first and second simulations show a dissimilar effect on GHG emissions from the open-field PV deployment strategy. Simulation I implies increased GHG emissions if open-field PV is being maximized. Competition with other RES and out-phasing of the limited nuclear capacity is the main driver for this effect. In contrast to the first simulation, the second simulation indicates a linear negative relation between increasing open-field PV and GHG emissions. This negative relation is driven by reduced electricity outputs of the coal TPP.
The true impact of increasing open-field PV on GHG emissions cannot be stated because the results from both simulations cannot be directly compared to each other. However, comparing both results to the current heat and electricity sectors on a few key points is possible. This comparison indicates that the second simulation better resembles the current situation. Implying that the linear negative relation between open-field PV and GHG emissions is more likely to exist in reality.

The second finding regarding GHG emissions is the linear negative relationship between increasing any type of PV and GHG emissions. This relation is not reported by Child nor by Diachuk[5], [6]. However, the linear relationship between PV and GHG emissions in Ukraine is reported by [65], but with a steeper gradient. The main driver for this difference is the assumption from [65] that any electricity produced by rooftop PV is consumed in Ukraine and therefore reduces the consumption of coal or gas. The data in this thesis indicate that the self consumption of PV is not guaranteed. Large cross-border flows can be expected when the share of PV becomes significant. The exported electricity would not directly result in GHG emission abatements in Ukraine. Still, the two different slopes can be compared to the literature, [66] presented average avoidance of CO_2 emissions by introducing PV and their presented values are more in line with the results from this thesis.

The impact of the PV deployment strategies on the Herfindahl-Hirschman Index differs per simulation. Both simulations agree on the positive effect of rooftop PV. The results show that increasing the rooftop PV capacities to supply 15% of electricity demand reduces the HHI by almost 15%. The data also indicates that the rooftop PV and combined strategy are equally cost-effective. On top of that, the first simulation showed that even maximizing the PV still leads to diverse heat and electric power sectors. However, the results differ on the effect of open-field PV. Maximizing the open-field PV indicates very strong increases in diversity, while the second simulation showed that the HHI remains almost constant when increasing the open-field capacity. The HHI resulting from the first simulation is difficult to project to the current Ukrainian power sector due to the large differences between the (sub) optimal results and the actual situation. This implies that the results from the second simulation are more representative. This would lead to the conclusion that the HHI is not impacted by increasing small increases in open-field PV.
However, a study from [67] on historical data reinforces this conclusion but contradicts the positive relationship between increasing rooftop PV and increasing diversity. The research analysed historical data and showed that the implementation of PV in the US since 2010 did not increase diversity. The author explains that this is the result of large investments in wind power in the same period, offsetting gains in diversity caused by increasing PV. This puts the results regarding diversity in perspective. As this historical example shows, increasing RES in the electricity sector is often done by introducing different technologies simultaneously, such as wind, PV and biomass. Not by introducing only a single technology. This implies that the increases in diversity this thesis presented are overestimations of the effect on the actual Ukrainian heat and electricity sectors.

5.2. Assessing the effects of introducing PV in the heat and electricity sector with literature

The data from both simulations showed that introducing PV into the electricity and heat sector requires roughly 27 GW of dispatchable technologies. This aligns with the currently installed coal (CHP) and hydropower plant capacities. The simulations imply that phasing out the current nuclear and CCGT is the most economical option. This option caused GHG emissions from the first simulation to be higher than the current 2020 emissions. Which is not in line with the predicted future GHG emission targets for Ukraine, as presented in section 2.4. The results from the second simulation do meet the GHG emission targets. They also show that the phase-out of nuclear and CCGT is the most economical option. This reduction in GHG emissions is also facilitated by a large increase in wind capacity. Reaching the GHG emissions targets could also be achieved by favouring CCGT and nuclear power over coal-fueled power plants. This finding is reinforced by [12], who showed using a brown field approach that it is beneficial for Ukraine to transfer from coal-fired power plants to gas-fueled power plants to reduce GHG emissions. They also confirmed the required dispatchable capacities. Their renewable scenario consists of 29,3 GW of dispatchable technologies, to support the 25 GW of variable renewable technologies.

The data also showed introducing large shares of PV does not require large additional investments in storage capacities. The data suggest that the currently available reservoirs and pumped hydro storage capacities can bridge the difference between supply and demand until 2030. This does require large investments in transport capacities since the hydro storage capacities are located along the two main rivers in Ukraine. Although the storage capacities might be sufficient, the data on cross-border flows shows that the power output of the hydro storage technologies should increase. The cross-border flow data showed large daily fluctuation which could be minimized if the storage technologies could charge and discharge at a faster rate. This is in line with the recommendations from the IEA [2]. They recommended updating and expanding the current turbines, to increase power outputs and overall efficiencies. Child [6], also confirms that the current storage capacities are sufficient. While exploring a 100% renewable energy system for Ukraine, they recommend introducing additional large storage facilities after the share of renewables increases beyond 80% of the total generation. This is envisioned by Child to occur after 2035.

The third general result highlights the difference in spatial availability of rooftop and open-field PV. The data suggest that the combined and rooftop PV strategy results in a gradual spread of PV throughout Ukraine. This gradual spread is not seen with the open-field deployment strategy. This strategy resulted in very regionally concentrated PV deployments. Both types of PV require for most regions the same size of interconnections. This indicates that they can be deployed simultaneously without requiring different networks. These result cannot be verified by [5], [6], [12] who evaluated Ukraine on a national level.

Lastly, the results obtained by maximizing different PV technologies indicate that electricity could supply a large part of the heat demand if enough (heat) storage capacity would be available. This would allow for a further reduction in coal (CHP) plants. This is not in line with the findings of Diachuck *et al.* [5]. This research concludes for each scenario that biomass should be the primary supplier of heat. The different conclusions can be explained by the difference in cost assumptions of both papers. This thesis used the estimations from the Danish energy agency [64], resulting in capital expenditure of 2200 €/kW and operational expenditure of 56.9 €/kW. While [5] determined capital expenditure of 532-250 €/kW an operational expenditure of 20 €/KW. These monetary differences originated from different assumptions in biofuel usage. Daichuks' model includes co-firing biofuel in exiting coal (CHP) plants. This alternative use of biomass is less capital expensive. Because the industry to process biomass in Ukraine does not yet exists, it's unlikely that large shares of biomass will be available by 2030. This makes co-firing biomass the more feasible option by 2030.

5.3. Assessing the main assumptions

The results from this thesis are affected by a few assumptions. One of the main assumptions resulted in the limited availability of open-field PV. This assumption excluded agricultural land to be used for open-field PV. Although the resulting 9.7 GW of available open-field potential cannot be verified in the literature due to a lack of data, it feels low compared to the 79 GW of estimated rooftop PV. The resulting 9.7 GW can be challenged in two ways. First a different and higher resolution database than the Globcover ESA database [50] used in this research, might identify additional suitable locations in Ukraine. This could result in a larger potential.

The assumption can also be challenged by considering agrivoltaics. Agrivoltaics are special PV panels which can be placed over food crops. Recent research on agrivoltaics [68] showed that for specific crops, yields do not decrease if placed under these PV panels. This would eliminate the ethical concerns regarding using agricultural land for electricity production. Research on the costs of agrivoltaics [69] demonstrated that the costs of installing agrivoltaics are comparable to the costs of installing roof or ground-mounted PV systems. These two factors indicate that the assumption might have been too conservative.

Another assumption was made to determine, the availability, orientations and inclines of rooftop PV per region. This paper only assessed one squared kilometre of Kyiv and assumed these results could be extrapolated to all the urban areas in Ukraine. This assumption can also be challenged because rooftop PV availability is also influenced by building type or the year the building is built. Based on the observation that the part of Kyiv that has been assessed was mainly populated with large multi-story communal buildings from the sixties. The estimations from this paper can be considered an overestimation of the true rooftop PV potential per region.

Calliope optimized the solutions based on total system costs. Therefore, all the cost assumptions used in this thesis greatly impact the results. Most cost assumptions are copied from the Eurocalliope model [32]. The cost assumptions in this research are based on data from the Danish Energy Agency [64]. This database has been constructed by assessing mostly Northern European electricity and heat production facilities. Child *et al.* [6] made cost estimations specifically for Ukraine, based on market consultancy. When the two data sources are compared they show some differences. For this research, this led to the reassessing of costs associated with PV technologies. The costs of other technologies have not been reassessed. Fully evaluating all the technology costs specifically for Ukraine might lead to different results. This could affect the costs abatement curve for GHG emissions, or the model's preference towards deploying CHP plants.

5.4. Limitations

Despite the results discussed above, this research has two limitations that are worthy of discussion in this section: the availability of data and a limited means to asses energy security.

The availability of accurate and verifiable data caused uncertainties in both demand predictions and the spatial resolution of Ukraine. Yearly demand is validated in subsection 3.3.5 and showed decent correlations with temperatures and comparable standard deviations as compared to the reference year of 2021. The ENTSO-E database [34] contained only one single year without any interruptions. This limited the ability to asses if 2021 is representative. No reference data could be found on the completeness of this database for Ukraine. This is mainly caused by the recent membership status of Ukraine and time delays in implementing various policies to start collecting data.
Data availability also affected the possible input years to 2015-2020, due to dependencies on different models for input generation. Due to time constraints, only 2018 has been used to generate results. This leaves plenty of room for uncertainties regarding the long-term feasibility of the results. Previous research has shown that using a multitude of different weather patterns improves reliability because it better captures low probability events [70], [71]. The choice of 2018 was based on its total RMSE as compared to the typical meteorological year. Choosing different parameters or setting weights to parameters might lead to different conclusions regarding the most untypical year. Both the demand profile and the yields of RES are based on a single year. This may result in an overestimation or underestimation of the impacts of the PV deployment strategies on the KPIs. The effects on the results can be estimated by adding a sensitivity analysis or by rerunning the same model for different years.
Data and literature, necessary to estimate RES potential and yields, were often only available on a national level. This limits the spatial resolution of the model. A higher spatial resolution might prove additional insights with regard to where to implement various technologies. This could provide more applicable solutions, as well as allow for better determination of how the future electricity and heat sector might look like.

Lastly, this thesis attempts to asses energy security in Ukraine based on the outputs from Calliope. How you measure energy security is not strictly defined and small differences exist between the major indices. For example, to quantify import dependency this paper uses the definition from [22]: "Net [resource] import as a percentage of total national [resource] supply". The WEF defines it as "Cost of energy imports (% GDP)" [23]. Both definitions result either in a 21% import dependency according to the first, or 39% according to the latter in 2020. The same goes for evaluating the HHI. The simplicity of calculating this index is its greatest strength and weakness. To calculate the HHI choices have to be made on how technologies are grouped. Technologies can be grouped by fuel consumption or technology, both groupings result in different HHI values. Because none of the major indices does explicitly state how they compute the HHI [21]–[23], the results obtained in this research cannot be compared to the literature. Besides different definitions of the KPIs, the indices also include many qualitative indicators. These can not be evaluated using the qualitative results from Calliope. This limited the assessment of energy security to the selected three KPIs.

6 Conclusion

Ukraine is currently facing large energy security risks caused by its conflict with Russia. Recent events showed that the Ukrainian electricity and heat sector can be disrupted by Russian strikes. Besides energy security concerns, Ukraine is also not meeting its emission targets. Introducing renewable energy sources could increase energy security in Ukraine and help comply Ukraine with GHG emission targets. Therefore this thesis aims to assess how different PV deployment strategies reinforce energy security and help comply with GHG emission targets.

The research question is answered with the following method. First, a literature review is done on energy security, the current status of the Ukrainian heat and electricity systems and the potential and yields of renewable energy sources in Ukraine. These insights are used for two simulations using the Calliope optimization framework. Calliope computes optimal and sub-optimal configurations, to match the 2030 electricity and heat supply and demand. Based on the two simulations the impact of different PV deployment strategies on the energy security key performance indicators (KPIs) are assessed. In this chapter the overall conclusion from both the literature review and the two simulations are stated.

6.1. Conclusions from the literature review

The literature review on energy security measurements showed that it is impossible to completely reassess any of the major indices. From the major indices three overlapping quantitative KPIs are selected. Imported electricity and fuel consumption of coal, methane and biomass, combined with the current use of these resources outside of the electricity and heat sectors allow for the assessment of the first KPI, the import ratio. Based on the deployment of different technologies on a regional scale the diversity of the heat and electricity sector can be determined using the Herfindahl–Hirschman index (HHI). Total GHG emissions from the electricity and heat sector is the third KPI. It provides insight into the sustainability of the solutions.

The literature review on the current status of the Ukrainian energy and heat sector revealed two results regarding energy security in Ukraine. It showed that the current heat and electricity sector is very dependent on fossil fuels. This affects both the GHG emissions as well as Ukraine's import dependency on fossil fuels. The review also showed the centralized nature of the Ukrainian electricity sector. Apart from coal, Ukraine is very dependent on large nuclear-, and hydropower plants. These require an extended transportation network to supply energy all over Ukraine. This leads to a relatively low diversity of generation capacity, decreasing Ukraine's resilience to energy security risks.

Analysis of the potential and yields of renewable energy sources suggest that overall Ukraine is gifted with an abundance of RES. Geospatial analysis and literature review on PV potential indicated a total of 79 GW of rooftop PV and 9.7 GW of open-field PV. Windpower potentials are even higher, literature and geospatial analysis indicated 440 GW of onshore wind and 140 GW of offshore wind potentials. Assessment of the hydropower potentials in Ukraine showed that this technology is already well developed. It also provides important storage capacities needed to buffer differences between supply and demand, caused by introducing more PV into the energy system. Lastly, the literature review indicated a large availability of sustainable biomass in Ukraine. It also indicated that currently, no infrastructure exists to collect, process and redistribute the biomass in Ukraine.

6.2. Conclusions from the simulations

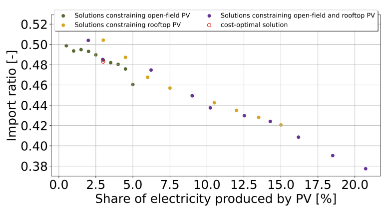
Three different PV deployment strategies are determined based on their method of installation. Rooftop PV, open-field PV and the combined deployment strategy. Two different simulations are used to determine the impact on the energy security KPIs. The first simulation explores the effects of the deployment strategies if they are being maximized. The second simulation explores the effects caused by smaller amounts of PV in the heat and electricity sector.

The following general conclusions can be drawn from the data. Introducing PV into the electricity and heat sector has a limited impact on the total installed coal (CHP) power plants. But does reduce their capacity factor significantly, which leads to a positive effect on the import ratio and GHG emissions. Also, introducing large shares of PV does not require large additional investments in storage capacities. The data suggest that the currently available reservoirs and pumped hydro storage capacities can bridge the difference between supply and demand. However, the power output of the current storage facilities should be increased to accommodate the increased variability of the generation capacity.

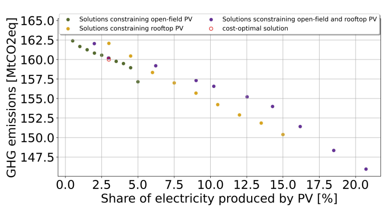
The simulations showed that each deployment strategy has a comparable effect on the KPIs indicating that introducing any form of PV always leads to increased energy security. MoThe results from the simulations indicate that the strategies equally affect the import dependency. However, the combined strategy is the most cost-efficient option for reaching lower import ratios. The results also showed that maximizing PV deployment leads to increased electricity imports to balance the difference between supply and demand. Solutions containing larger storage capacities still relied on electricity imports for balance. This offset the effect of reducing the coal consumption on the import ratio and prevented the import ratio to lower beyond 36%.

GHG emissions are affected the same by each deployment strategy. The data indicates a linear relationship between introducing PV and lowering GHG emissions. The results show that the combination of rooftop and open-field PV is the most cost-effective strategy.

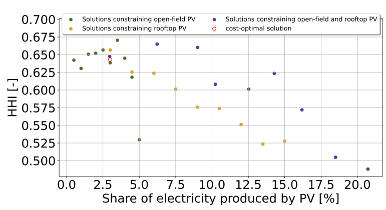
The HHI is impacted the least by the open-field deployment strategy. At low installed open-field capacities, the HHI remains almost constant. On the other hand, rooftop PV has the biggest positive impact on the HHI. However, secondary literature does not support the trend seen in this paper. Actual data reported a negative effect between increasing PV and diversity. This indicates that the simplicity of the HHI index does not incorporate all real-world effects.



(a) Overall impact of deployment strategies on the import ratio



(b) Overall impact of deployment strategies on the GHG emissions



(c) Overall impact of deployment strategies on the HHI

To conclude, the three PV deployment strategies all positively affect the energy security KPIs and help comply with GHG emissions. The rooftop and combined strategy do this in a similar way mainly by reducing the coal consumption in the heat and electricity sectors. The combined strategy is more cost-effective in reducing GHG emissions and the import ratio than deploying rooftop PV only. Open-field PV availability is limited which reduces its potential to increase energy security in Ukraine. Still, it is a very cost-effective technology and could play a role if only small amounts of PV in Ukraine are envisioned.

6.3. Recommendations

The literature review showed two main topics that could be addressed in future research. The first topic is that this research only addresses three quantitive KPIs to assess energy security. Combining these results with assessing the impact of different PV deployment strategies on the qualitative KPIs. Will provide a complete overview of how energy security is impacted by implementing PV in Ukraine. Thi66s would allow decision-makers to make a completely informed decision regarding how to include PV in the heat and electricity sector.
The second topic is the limited data on regional PV potential in Ukraine. This required to estimate the potentials for rooftop and open-field PV have been determined by geospatial analysis. Rooftop PV estimations are based on a small sample size, and the open-field estimations can be considered conservative. It is recommended to improve the estimations done in this research and increase the spatial resolution of the results. This will allow for more detailed planning on the local potential of PV in Ukraine.

The results also showed two points to be addressed in future research. Starting with the observations that the results showed little diversity between the solutions. By maximizing the different PV deployment technologies this study explored a specific part of the solution space. Depending on the outcome of the conflict or the need for certain combinations of technologies in the heat and electricity sector, specific interest in different solutions might arise. These interests can be explored using the model in this study as a blueprint. Changing the method to find sub-optimal solutions would reveal different parts of the solution space, specifically addressing new interests.
The second point is the different relationship between implementing PV in the considered sectors and increasing diversity found in this paper and the literature. This phenomenon can be partly explained by the loose definition of the HHI with regard to the electricity and heat sectors. Deeper research on a universal method to determine diversity in energy systems could lead to improved comparability of energy security indices.

Finally, two general recommendations for future research can be made. The results in this paper are obtained using a greenfield approach. This allowed for an interesting insight into the possibilities of PV in Ukraine. Using this approach allowed only for limited conclusions regarding required dispatchable and storage capacities. More in-depth conclusions on which existing powerplants should provide these roles by 2030 could be explored using the brownfield approach, which takes the current state into account.

The last recommendation would be to explore how different renewable energy technologies impact energy security in Ukraine. This might provide broader insights into which technologies are the most beneficial for Ukraine to meet GHG emissions and increase energy security.

The current conflict, the unclear outcome, and the current increased cooperation between the European Union and Ukraine will impact any forecast previously made to asses Ukraine's energy system. This research laid part of the groundwork for future assessments regarding the Ukrainian heat and electricity system. Which could ultimately lead to a sustainable and secure system in Ukraine.

References

[1] BBC News, *War in ukraine*, Accessed: October 31, 2022, 2023. [Online]. Available: https://www.bbc.com/news/world-60525350.

[2] International Energy Agency, "Ukraine energy profile," 2020.

[3] International Energy Agency, "Eastern Europe, Caucasus and Central Asia - Energy Policies Beyond IEA Countries," 2015.

[4] S. Lorenczik, S. Kim, B. Wanner, *et al.*, "Projected costs of generating electricity," Organisation for Economic Co-Operation and Development, Tech. Rep., 2020.

[5] O. Diachuk, M. Chepeliev, R. Podolets, *et al.*, "Transition of ukraine to the renewable energy by 2050," 2017.

[6] M. Child, C. Breyer, D. Bogdanov, and H. J. Fell, "The role of storage technologies for the transition to a 100% renewable energy system in ukraine," vol. 135, Elsevier Ltd, 2017, pp. 410–423.

[7] M. J. Bradshaw, "The geopolitics of global energy security," *Geography Compass*, vol. 3, no. 5, pp. 1920–1937, 2009.

[8] M. d. l. E. M. Pérez, D. Scholten, and K. S. Stegen, "The multi-speed energy transition in europe: Opportunities and challenges for eu energy security," *Energy Strategy Reviews*, vol. 26, p. 100 415, 2019.

[9] A. B. Wilson, "European energy security strategy," *European Parliamentary Research Service*, 2015.

[10] Eurostat, *Energy statistics - quantities, annual data- energy balances*, Accessed on 25-10-2022. [Online]. Available: https://ec.europa.eu/eurostat/databrowser/view/NRG_BAL_C/default/table?lang=en&category=nrg.nrg_quant.nrg_quanta.nrg_bal.

[11] S. Bouckaert, A. F. Pales, C. McGlade, *et al.*, "Net zero by 2050: A roadmap for the global energy sector," 2021.

[12] D. Saha, M. V. Mettenheim, F. Meissner, C. Stiewe, and G. Zachmann, "Implementing the National Emissions Reduction Plan (NERP): How should Ukraine's power plant park look like in 2033?" 2021.

[13] T. Tröndle, J. Lilliestam, S. Marelli, and S. Pfenninger, "Trade-offs between geographic scale, cost, and infrastructure requirements for fully renewable electricity in europe," *Joule*, vol. 4, pp. 1929–1948, 9 Sep. 2020.

[14] M. Child, C. Kemfert, D. Bogdanov, and C. Breyer, "Flexible electricity generation, grid exchange and storage for the transition to a 100% renewable energy system in europe," *Renewable Energy*, vol. 139, pp. 80–101, Aug. 2019.

[15] N. Lefèvre, *Energy security and climate policy: assessing interactions*. IEA/OECD, 2007.

[16] The World Bank, "Energy security issues," 2005.

[17] B. K. Sovacool, "The methodological challenges of creating a comprehensive energy security index," *Energy policy*, vol. 48, pp. 835–840, 2012.

[18] K. Narula and B. S. Reddy, "Three blind men and an elephant: The case of energy indices to measure energy security and energy sustainability," *Energy*, vol. 80, pp. 148–158, 2015.

[19] A. Cherp, "Defining energy security takes more than asking around," *Energy Policy*, vol. 48, pp. 841–842, 2012.

[20] International Energy Agency, *Energy Security and Climate Policy - Assessing Interactions*. OECD, Mar. 2007.

[21] World Economic Counsel, "World energy trilemma index - 2022," 2022.

[22] US Chamber of Commerce, "International Index of Energy Security Risk: Assessing Risk in a Global Energy Market," 2020.

[23] World Economic Forum and Accenture, "The global energy architecture performance index report 2017," 2017.

[24] Y. Kharazishvili, A. Kwilinski, O. Sukhodolia, H. Dzwigol, D. Bobro, and J. Kotowicz, "The systemic approach for estimating and strategizing energy security: The case of ukraine," *Energies*, vol. 14, no. 8, p. 2126, 2021.

[25] United Nations Framework Convention on Climate Change, *The paris agreement*, https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement, 2015.

[26] General Assembly, "Sustainable development goals," *SDGs Transform Our World*, vol. 2030, pp. 6–28, 2015.

[27] European Commission, *Fit for 55 package*, https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/actions-being-taken-eu/fit-55-package_en, 2021.

[28] International Energy Agency, *Key emissions figures*, Accessed on 02-02-2023. [Online]. Available: https://www.iea.org/data-and-statistics/data-tools/greenhouse-gas-emissions-from-energy-data-explorer.

[29] N. Iwaszczuk, I. Zapukhliak, A. Iwaszczuk, O. Dzoba, and O. Romashko, "Underground gas storage facilities in ukraine: Current state and future prospects," *Energies*, vol. 15, no. 18, p. 6604, 2022.

[30] T. Kasperski, "Nuclear power in ukraine: Crisis or path to energy independence?" *Bulletin of the Atomic Scientists*, vol. 71, no. 4, pp. 43–50, 2015.

[31] S. Pfenninger and B. Pickering, "Calliope: A multi-scale energy systems modelling framework," *Journal of Open Source Software*, vol. 3, no. 29, p. 825, 2018.

[32] B. Pickering, F. Lombardi, and S. Pfenninger, "Diversity of options to eliminate fossil fuels and reach carbon neutrality across the entire european energy system," *Joule*, vol. 6, pp. 1253–1276, 6 Jun. 2022.

[33] UkrStat, *Ukrainian state statistics service*, Accessed on 08-11-2022. [Online]. Available: urkstat.gov.ua.

[34] ENTSO-E, *Total load- day ahead/actual database*, Accessed on 08-12-2022. [Online]. Available: https://transparency.entsoe.eu/load-domain/r2/totalLoadR2/show.

[35] ENTSO-E, *Grid map*, Accessed on 27-11-2022. [Online]. Available: https://www.entsoe.eu/data/map/.

[36] J. Muñoz-Sabater, E. Dutra, A. Agustı-Panareda, *et al.*, "Era-5-land: A state-of-the-art global reanalysis dataset for land applications," *Earth System Science Data*, vol. 13, no. 9, pp. 4349–4383, 2021.

[37] O. Ruhnau, L. Hirth, and A. Praktiknjo, "Time series of heat demand and heat pump efficiency for energy system modelling," *Scientific Data*, vol. 6, 1 Dec. 2019.

[38] I. Staffell and S. Pfenninger, "Using bias-corrected reanalysis to simulate current and future wind power output," *Energy*, vol. 114, pp. 1224–1239, Nov. 2016, ISSN: 03605442. DOI: 10.1016/j.energy.2016.08.068.

[39] International Energy Agency and Eurostat and OECD, "Energystatistics," 2004.

[40] International Energy Agency, *Electricty consumption per sector*. IEA, 2022.

[41] S. Kysil, "The issue of transport infrastructure organization for storage of electric vehicles in the urban environment of the largest cities," 2017.

[42] T. Boßmann and I. Staffell, "The shape of future electricity demand: Exploring load curves in 2050s germany and britain," *Energy*, vol. 90, pp. 1317–1333, 2015.

[43] National Bank of Ukraine, *Macro economical indicators gdp industry 2018*, Accessed on 03-11-2022. [Online]. Available: https://bank.gov.ua/ua/statistic/macro-indicators.

[44] National Bank of Ukraine, *Macro economical indicators gdp agriculture 2018*, Accessed on 03-11-2022. [Online]. Available: `https://bank.gov.ua/ua/statistic/macro-indicators`.

[45] O. Motlagh, P. Paevere, T. S. Hong, and G. Grozev, "Analysis of household electricity consumption behaviours: Impact of domestic electricity generation," *Applied Mathematics and Computation*, vol. 270, pp. 165–178, 2015.

[46] M. Schiavina, S. Freire, and K. MacManus, *GHS-POP R2019A–GHS population grid multitemporal (1975–1990–2000–2015): European Commission, Joint Research Centre (JRC)[Dataset]*, 2019.

[47] International Energy Agency, *Heating-analyses*, 2022. [Online]. Available: `https://www.iea.org/reports/heating`.

[48] ENTSO-E, *Grid map*, Accessed on 12-12-2012. [Online]. Available: `https://transparency.entsoe.eu/transmission-domain/physicalFlow/show`.

[49] *History, Today and Prospects*. Institute of Renewable Energy, National Academy of Sciences of Ukraine, 2020, ISBN: 978-966-999-070-9.

[50] P. Defourny, L. Schouten, S. Bartalev, *et al.*, "Accuracy assessment of a 300 m global land cover map: The globcover experience," 2009.

[51] T. Tröndle, S. Pfenninger, and J. Lilliestam, "Home-made or imported: On the possibility for renewable electricity autarky on all scales in europe," *Energy strategy reviews*, vol. 26, p. 100 388, 2019.

[52] K. Mainzer, D. Schlund, S. Killinger, R. McKenna, and W. Fichtner, "Rooftop PV potential estimations: Automated orthographic satellite image recognition based on publicly available data," *Photovoltaic Solar Energy Conference*, 2016.

[53] P. Mooney, M. Minghini, *et al.*, "A review of openstreetmap data," 2017.

[54] S. Pfenninger and I. Staffell, "Long-term patterns of european pv output using 30 years of validated hourly reanalysis and satellite data," *Energy*, vol. 114, pp. 1251–1265, Nov. 2016.

[55] S. Kudria, I. Ivanchenko, B. Tuchynskyi, K. Petrenko, O. Karmazin, and O. Riepkin, "Resource potential for wind-hydrogen power in ukraine," *International Journal of Hydrogen Energy*, vol. 46, pp. 157–168, 1 Jan. 2021.

[56] Y. Makarovskiy and V. Zinych, "Wind Energy Potential Assessment of Ukraine," 2014, pp. 169–178.

[57] N. Antoniuk, M. Baldzhy, and. Perkhach, "The performance potential of wind energy in ukraine and prospects for its recovery after the war," *Polityka Energetyczna – Energy Policy Journal*, vol. 25, pp. 91–104, 3 Sep. 2022, ISSN: 1429-6675. DOI: `10.33223/epj/153978`.

[58] A. Konechenkov, K. Knysh, galyna Shmidt, *et al.*, "Wind power sector overview 2020," 2020.

[59] D. Stefanyshyn, "On peculiarities of hydropower development in the world and in ukraine," National University of Water and Environmental Engineering, 2018.

[60] T. Kurbatova and H. Khlyap, "State and economic prospects of developing potential of non-renewable and renewable energy resources in ukraine," *Renewable and Sustainable Energy Reviews*, vol. 52, pp. 217–226, Aug. 2015.

[61] C. Mazzetti, B. Krzeminski, C. Barnard, F. Wetterhall, and C. Prudhomme, "River discharge and related historical data from the European Flood Awareness System, v3. 0, Copernicus Climate Change Service (C3S) Climate Data Store (CDS)," 2019.

[62] A. Wąs, P. Sulewski, N. Gerasymchuk, *et al.*, "The potential of ukrainian agriculture's biomass to generate renewable energy in the context of climate and political challenges—the case of the kyiv region," *Energies*, vol. 15, 18 Sep. 2022, ISSN: 19961073. DOI: `10.3390/en15186547`.

[63] H. Junginger and T. Helienzna, "Assement of the sustainable potential of biomass from forest and agricultural residues for export from ukraine to the european union," bioTrade2020+, 2015.

[64] Danish Energy Agency, *Technology data for generation of electricity and heat*, `https://ens.dk/en/our-services/projections-and-models/technology-data/technology-data-generation-electricity-and`, Accessed on 2023-01-17.

[65] G. Trypolska and A. Rosner, "The use of solar energy by households and energy cooperatives in post-war ukraine: Lessons learned from austria," *Energies*, vol. 15, no. 20, p. 7610, 2022.

[66] C. Breyer, O. Koskinen, and P. Blechinger, "Profitable climate change mitigation: The case of greenhouse gas emission reduction benefits enabled by solar photovoltaic systems," *Renewable and Sustainable Energy Reviews*, vol. 49, pp. 610–628, 2015.

[67] J. E. Kim and T. Tang, "Preventing early lock-in with technology-specific policy designs: The renewable portfolio standards and diversity in renewable energy technologies," *Renewable and Sustainable Energy Reviews*, vol. 123, p. 109 738, 2020.

[68] M. Wagner, J. Lask, A. Kiesel, *et al.*, "Agrivoltaics: The environmental impacts of combining food crop cultivation and solar energy generation," *Agronomy*, vol. 13, no. 2, p. 299, 2023.

[69] A. Agostini, M. Colauzzi, and S. Amaducci, "Innovative agrivoltaic systems to produce sustainable energy: An economic and environmental assessment," *Applied Energy*, vol. 281, p. 116 102, 2021.

[70] I. Staffell and S. Pfenninger, "The increasing impact of weather on electricity supply and demand," *Energy*, vol. 145, pp. 65–78, 2018.

[71] A. P. Hilbers, D. J. Brayshaw, and A. Gandy, "Importance subsampling: Improving power system planning under climate-based uncertainty," *Applied Energy*, vol. 251, p. 113 114, 2019.

A

Typical seasonal week demand and temperature curves

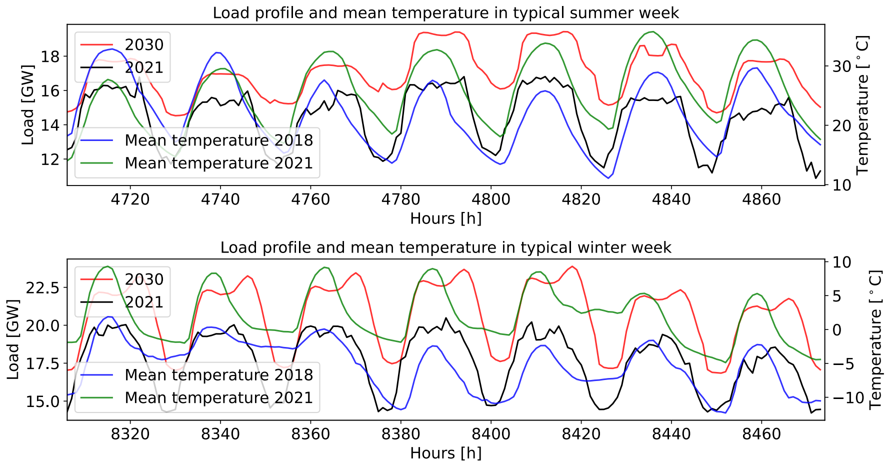


Figure A.1: 2021 and 2030 summer and winter Load curves and correlation with their underlying temperature

B

Additional graphic results from maximizing the PV deployments

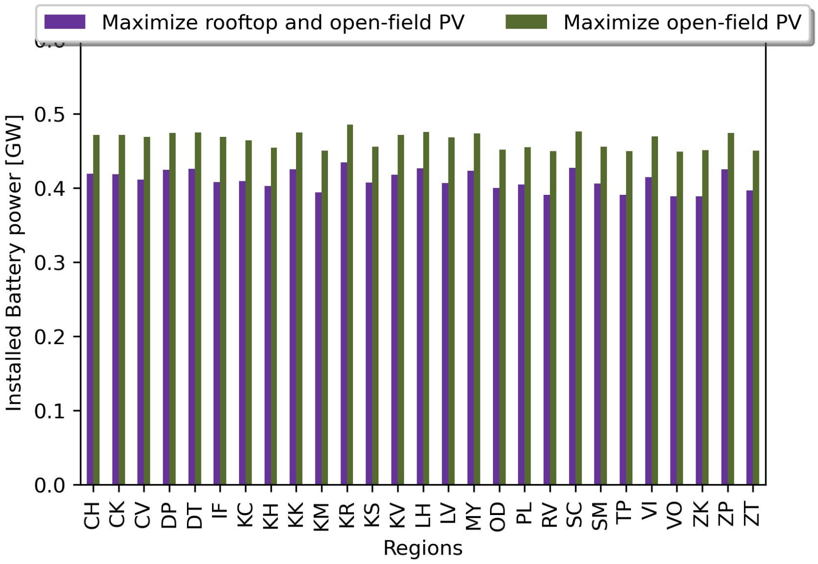


Figure B.1: The bars represent the average battery capacity required for each deployment strategy with the 10% cost slack constraint. Due to similarities between the rooftop PV and combined strategy, they are combined in the purple bars. It shows that all strategies require similar amounts, and similar distributed battery capacities

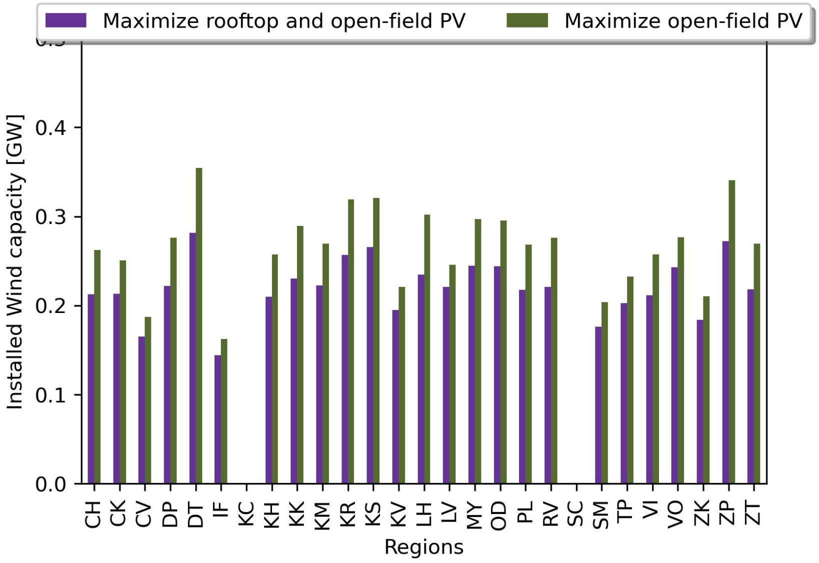


Figure B.2: The bars represent the average wind capacity required for each deployment strategy with the 10% cost slack constraint. Due to similarities between the rooftop PV and combined strategy, they are combined in the purple bars. It shows that all strategies require similar amounts, and similar distributed wind capacities

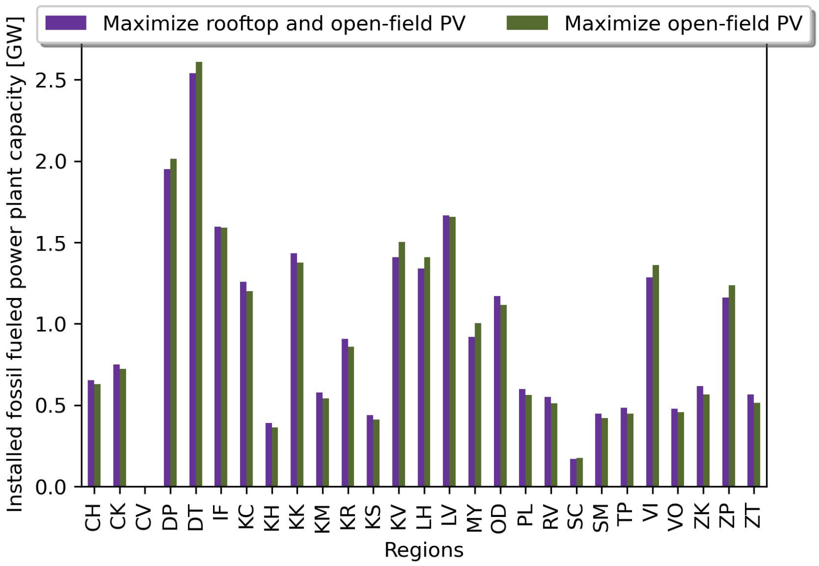
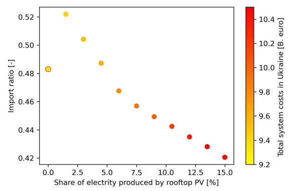


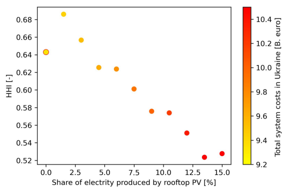
Figure B.3: The bars represent the average fossil-fueled capacity required for each deployment strategy with the 10% cost slack constraint. Fossil-fueled capacities are defined as the sum of coal power CCGT, and CHP plants. Due to similarities between the rooftop PV and combined strategy, they are combined in the purple bars. It shows that all strategies require similar amounts, and similar distributed fossil-fueled capacities

C

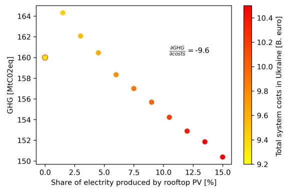
Additional graphic from incrementally increasing the PV deployments



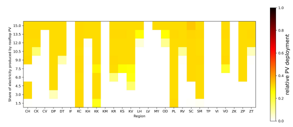
(a) Import ratio and total system cost versus the share of electricity produced by rooftop PV



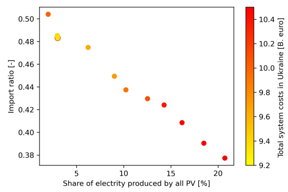
(b) HHI and total system cost versus the share of electricity produced by rooftop PV



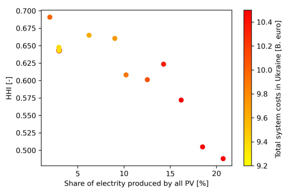
(c) GHG emissions and total system cost versus the share of electricity produced by rooftop PV



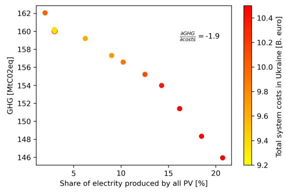
(d) Shares of rooftop PV potential installed in each region for each increment



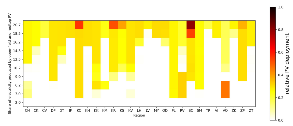
(e) Import ratio and total system cost versus the share of electricity produced by PV



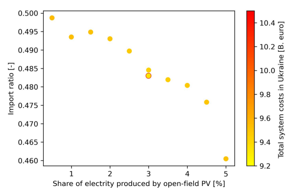
(f) HHI and total system cost versus the share of electricity produced by PV



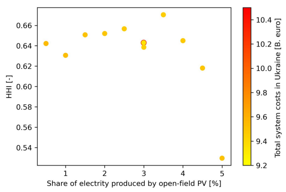
(g) GHG emissions and total system cost versus the share of electricity produced by PV



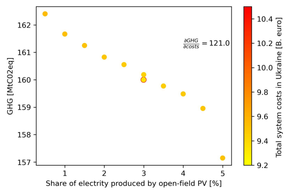
(h) Shares of PV potential installed in each region for each increment



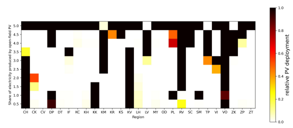
(i) Import ratio and total system cost versus the share of electricity produced by open-field PV



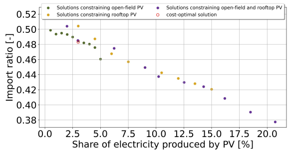
(j) HHI and total system cost versus the share of electricity produced by open-field PV



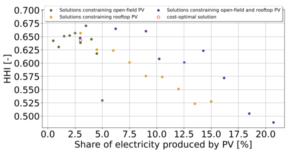
(k) GHG emissions and total system cost versus the share of electricity produced by open-field PV



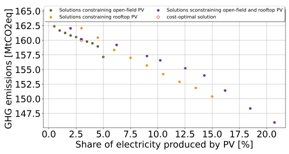
(l) Shares of open-field PV potential installed in each region for each increment



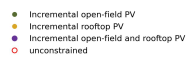
(m) Overall impact of deployment strategies on the import ratio



(n) Overall impact of deployment strategies on the HHI



(o) Overall impact of deployment strategies on the GHG emissions



D

List of abbreviations used to describe the regions

Table D.1: Full list of abbreviations used to describe the regions

Abbreviation	English name:
CH	Chernihiv
CK	Cherkasy
CV	Chernivtsi
DP	Dnipropetrovsk
DT	Donetsk
IF	Ivano-Frankivsk
KC	ity of Kyiv
KH	Kirovohrad
KK	Kharkiv
KM	Khmelnytskiy
KR	Autonomous republic of Crimea
KS	Kherson
KV	Kyiv
LH	Luhansk
LV	Lviv
MY	Mikolayiv
OD	Odesa
PL	Poltava
RV	Rivne
SC	city of Sevastopol
SM	Sumy
TP	Ternopil
VI	Vinnytsya
VO	Volyn
ZK	Zakarpattya
ZP	Zaporizhzhya
ZT	Zhytomyr