Energy Community

Study on flexibility options to support decarbonization in the Energy Community

Trinomics, Artelys

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Disclaimer

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Acronyms

AL	Albania
BA	Bosnia and Herzegovina
CACM	Capacity allocation and congestion management
CAES	Compressed air energy storage
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CESEC	Central and South Eastern Europe energy connectivity
CO_2	Carbon dioxide
CP	Contracting party
DR	Demand response
DSO	Distribution system operator
ECRB	Energy Community Regulatory Board
EnC	Energy Community
EU	European Union
EV	Electric vehicle
GE	Georgia
ICT	Information and communications technology
mFFR	Manual frequency restoration reserve
MD	Moldova
ME	Montenegro
MK	North Macedonia
MS	Member state
NEMO	Nominated electricity market operator
NTC	Net transfer capacity
O&M	Operation & maintenance
OCGT	Open-cycle gas-turbine
PHS	Pumped hydro storage
RES	Renewable energy sources
RS	Serbia
T&D	Transmission and distribution
TRL	Technology readiness level
TSO	Transmission system operator
UA	Ukraine
vRES	Variable renewable energy sources
XK	Kosovo*

*All references to Kosovo shall be understood in full compliance with United Nations' Security Council Resolution 1244 and without prejudice to the status of Kosovo.

1 Introduction

This report presents the main findings of the "Study on flexibility options to support decarbonisation in the Energy Community", which was delivered as a set of different in-depth reports listed below. Flexibility solutions allow the power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales. This report assesses flexibility solutions needed to support variable renewable energy sources (vRES) deployment in the Energy Community (EnC), from the daily to the seasonal timescale[2].

The detailed findings have been presented in previous Task reports which focus on:

- ✓ Discussing what flexibility is, what its main contributions and drivers are, and characterising selected flexibility sources (Task 1)[3];
- ✓ Identifying the existing flexibility sources, analysing the flexibility needs across different timeframes (daily, weekly and annual) in the Energy Community as well as indicating the optimal flexibility portfolio in each Contracting Party (CP) in 2030 and 2040 (Tasks 2 & 3)[4]; and
- ✓ Providing recommendations for improvement of the legal, regulatory and institutional frameworks to enable 1) the efficient utilisation of flexibility sources and 2) the development of additional flexibility sources in order to cost-efficiently meet future flexibility needs while assuring security of supply standards in the Energy Community (Tasks 4 & 5) [5].

The remainder of this document is structured as follows: Section 2 introduces the main flexibility sources, and in Section 3 we evaluate the current use of these sources and the cost-optimal flexibility portfolios by 2030 and 2040. Section 4 identifies policy and regulatory barriers for flexibility deployment and utilisation, and provides recommendations to foster flexibility in the Contracting Parties.

[2] Flexibility required at the sub-hourly timescale (reserves, inertia), adequacy issues (considering extreme events and various weather years), or coming from internal grid constraints (congestions) were not included in the scope of this study.

[3] Trinomics and Artelys (2021) Study on flexibility options to support decarbonization in the Energy Community - Task 1: Analysis of technical and non-technical sources of flexibility

[4] Artelys and Trinomics (2022) Study on flexibility options to support decarbonization in the Energy Community - Tasks 2&3

[5] Trinomics and Artelys (2022) Study on flexibility options to support decarbonization in the Energy Community - Tasks 4&5

2 Overview of flexibility sources

This section introduces the theory and main concepts related to power system flexibility, as well as sets the stage for the overall project analysing the contributions of different options to meet the future electricity system flexibility needs of the Energy Community Contracting Parties.

2.1 What is flexibility?

Power system flexibility can be defined as the ability of a "power system to reliably and cost-effectively manage the variability and uncertainty [of supply and demand] across all relevant timescales"[6], or due to other causes such as transmission outages. Flexibility sources can be defined as the technical and non-technical solutions which provide or facilitate the provision of flexibility, and thus help to ensure the balancing and proper technical functioning of a power system.

Flexibility sources are in particular essential to operate electricity systems with a high number of non-dispatchable power generation units connected to the grid having variable outputs throughout the year. The main purpose of flexibility sources is to contribute to:

- ✓ Facilitating deployment of intermittent RES, and
- ✓ Ensuring system stability and contributing to security of supply, while
- ✓ Minimising system costs

2.2 Drivers of flexibility needs in the Energy Community

The flexibility needs of the Energy Community Contracting Parties are expected to increase in the future, due to three main reasons:

- ✓ Increased penetration of intermittent renewable energy sources: Given the clean energy transition process, Energy Community Contracting Parties will need to accelerate the phase-out of their carbon-intensive power (and heat) generation facilities, with the projections of the Carbon Pricing Design for the Energy Community study[7] of 2021 pointing to a significant uptake of RES in total generation as soon as in this decade;
- ✓ Phase out of coal-based power generation: It is expected that a gradual phase out of coal-based generation in the Contracting Parties will take place, at different speeds, and due to a number of factors – actions can be expected based on the Decarbonisation Roadmap of the Energy Community, carbon pricing principles, and the implementation of the EU Large Combustion Plants Directive and the Industrial Emissions Directive is also due;
- ✓ Potential for disruptions to the energy system: More frequent extreme weather and potential reductions in hydroelectric flows or wind availability due to climate change, as well as any other significant disturbances, could be observed. Moreover, the use of natural gas-based plants for the provision of flexibility could increase the exposure to natural gas supply disruptions or price spikes.

[6] IEA (2018) Status of Power System Transformation 2018 https://iea.blob.core.windows.net/assets/ede9f1f7-282e-4a9b-bc97-a8f07948b63c/Status_of_Power_System_Transformation_2018.pdf
[7] EnC (2021), A carbon pricing design for the Energy Community. Final Report. https://www.energy-community.org/dam/jcr:82a4fc8b-c0b7-44e8-b699-0fd06ca9c74d/Kantor_carbon_012021.pdf

2.3 Overview of flexibility sources

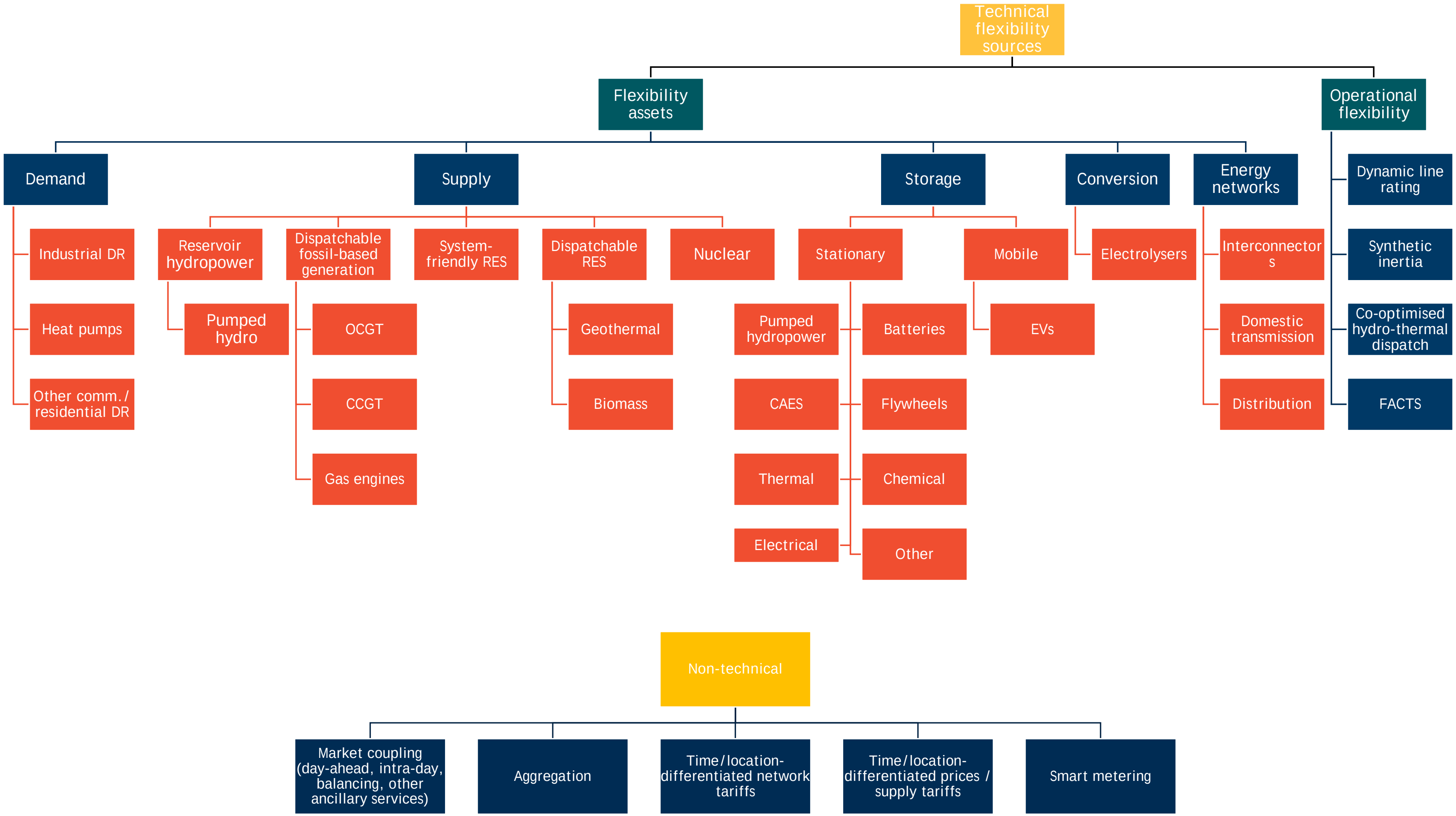
The nature of flexibility sources affects their ability to provide different flexibility services to the power system as well as their economic viability. Flexibility sources can be technical or non-technical. *Technical sources* of flexibility comprise physical flexibility assets (such as dispatchable power plants, demand-response and storage) and *operational flexibility* actions that enhance the effective flexibility capabilities of these physical assets. *Non-technical* sources of flexibility relate to policies and measures which incentivise the availability and use of technical flexibility sources at the transmission and distribution level. The figure below provides a non-exhaustive overview of several technical and non-technical flexibility sources.

Flexibility sources, moreover:

- ✓ Can provide flexibility in specific timeframes, from the intra-hourly to the seasonal. While most sources can provide flexibility in several timeframes, the technical and economic characteristics usually make them more suited for a more restricted range of timeframes;
- ✓ Are distinguished by a number of technical characteristics which shape their ability to provide flexibility services in the different timeframes. Some of the most important technical characteristics include the energy and power capacity of the sources, ramping up/down limits, response time and charging/discharging time, as well as the conversion efficiency;
- ✓ The cost of flexibility sources is, along their technical characteristics, pivotal to their ability to provide services to the electricity system. Costs can be broadly categorised as fixed costs (e.g. depreciation and capital costs, overhead costs, fixed O&M costs) and variable (e.g. fuel/electricity, losses, carbon emission and variable O&M costs, ramp-up and ramp-down costs, and start-up/activation costs [8]). In addition to direct costs to the reservation and activation of flexibility sources, there are opportunity costs associated with the provision of flexibility, as well as costs associated with the deployment and maintenance of automated control and ICT systems.

[8] Start-up costs are incurred only once per activation and are thus independent of the actual volume of flexibility provided. However, start-up costs are logically related to the number of activations and thus variable to a certain extent, and these costs will be included in bids of the unit operator. As they influence the short run marginal cost they are here classified as variable, although they are independent of the flexibility volume provided in each run.

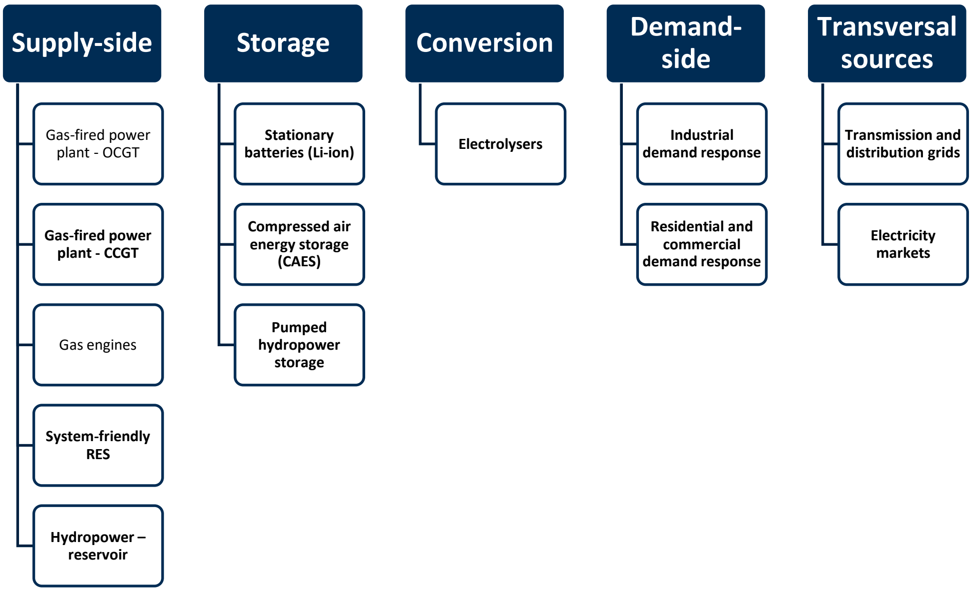
Figure 1 Classification of technical and non-technical flexibility sources with non-exhaustive examples



2.4 Characterisation of selected flexibility sources

Starting from a long-list of flexibility sources, a database was developed detailing 13 flexibility sources (shown below) chosen for their significant variation in characteristics such as their location in the electricity value chain, flexibility timeframe, and current and future flexibility potential.

Figure 2 Selected flexibility sources for detailed analysis

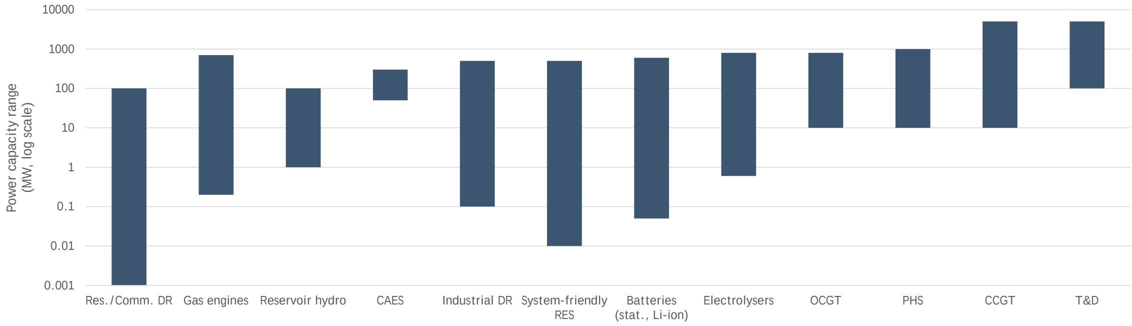


The analysis of the technical characteristics of these sources indicates that:

- ✓ The selected flexibility sources cover, in combination, all flexibility timeframes, from the intra-hourly to the seasonal. However, as several sources are better suited to providing flexibility in certain timeframes, any analysis of flexibility options for the Energy Community or Contracting Parties has to consider the needs in each timeframe;
- ✓ Revenue stacking (i.e. the combination of different revenue streams of flexibility providers in order to maximise profitability) should be an important strategy to achieve economic viability;
- ✓ The energy capacity[9] of the sources strongly depends on factors not related to technological aspects (such as availability of natural gas), with the notable exception of storage technologies;
- ✓ The power capacity of the flexibility sources (i.e. the maximum energy that can be provided at a certain instance) is more linked to the specific technologies concerned (as opposed to energy capacity, which is more context-dependent as mentioned above) as well as, in the case of aggregated flexibility sources, on the deployment levels;
- ✓ Most of the selected flexibility sources have a high technological maturity (with a technological readiness level close to 9 out of 10). The exceptions are electrolysers and compressed air energy storage, which show a Technology Readiness Level (TRL) of respectively 8 and 6-9. Despite the high maturity of the surveyed sources, this does not mean that further technological improvements are not needed primarily to decrease investment and O&M costs and to further improve their technical performance.

[9] Energy capacity and power capacity are further explained in Section 4

Figure 3 Typical maximum and minimum power capacity of selected flexibility sources



Note: Electricity markets are not shown given they do not have an intrinsic power capacity

Source: own elaboration

Flexibility sources have different costs, which are often system-dependent. In general, options focused on changes to system operation and market design tend to be cheaper than new sources of flexibility. Still, changes to system operation and market design do have implementation costs and often require institutional changes.

3 The role of flexibility sources in the Energy Community and future flexibility needs

This section quantifies the need for, and determines the role of, flexibility options to support the cost-efficient decarbonization of the electricity system in the Energy Community towards 2040. Future flexibility needs are analysed and cost-optimal portfolios of flexibility solutions are determined considering a wide range of scenarios in terms of variable renewable energy sources (vRES) deployment, coal-fired power generation phase-out and levels of interconnection capacity.[10]

3.1 Scenario definition and main modelling hypotheses

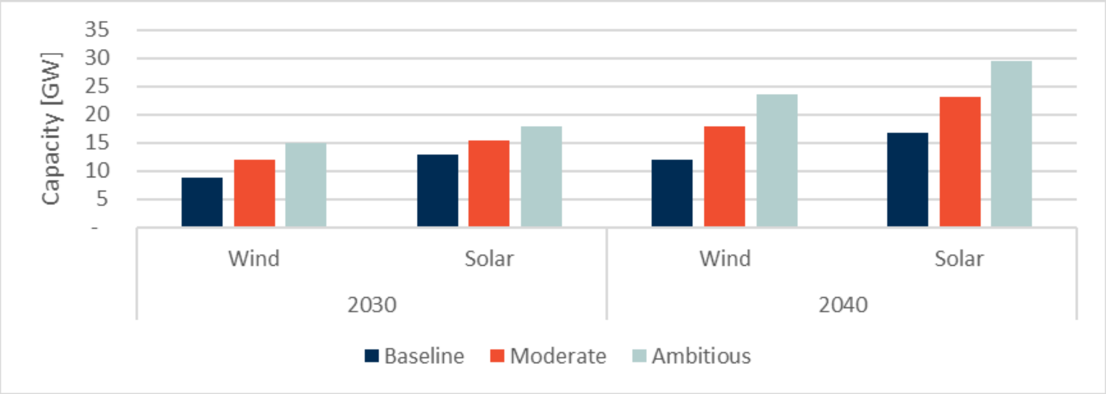
Renewable energy sources will play an increasing role by 2030, 2040 - to a varying extent depending on the scenarios

Three power generation capacity scenarios are considered in this study, for 2030 and 2040:

- ✓ a Baseline scenario[11], reflecting a *business-as-usual* development, with relatively slow uptake of renewable energy sources (RES).
- ✓ a Moderate scenario, which reflects an intermediate scenario between Baseline and Ambitious.
- ✓ an Ambitious scenario[12], with strong decarbonization of the power generation sector, due to a high uptake of RES and almost complete phase-out of lignite and coal-based power generation by 2040.

All scenarios rely on scenarios from "A carbon pricing design for the Energy Community" study and feedbacks from CPs. Figure 4 presents the capacity evolution of wind and solar energy for both the 2030 and 2040 horizons and the three scenarios. Significant differences arise between the Baseline and the Ambitious scenario, with a vRES uptake (combining wind and solar energy) of +50% in 2030 and +85% in 2040 in the Ambitious scenario in comparison to the Baseline.

Figure 4 Total vRES capacity in the Energy Community in the different scenarios, for both 2030 and 2040



The capacity scenarios are complemented by two levels of cross-border exchange capacities, reflecting two levels of market integration. One approach restricts the utilisation of NTC capacities to the values

[10] It is important to note that the present analysis does not take into account the consequences related to the invasion of Russia in Ukraine since 24 February 2022. Nonetheless, the assessments carried out for the years 2030 and 2040 consider a full synchronisation of Ukraine and Moldova with the Continental European Synchronous Area (CESA).
[11] Based on the Baseline scenario of the EnC-Carbon Pricing study
[12] Based on Gradual Carbon Pricing strategy and Market integration scenario (GradualCP-MInt) from the EnC-Carbon Pricing study

observed in the past (Fragmented Market scenario), whereas the other one makes available 70% of the nominal transmission capacities for trading purposes (Market Integration scenario).

Existing flexibility sources dominated by coal-fired power plants and interconnections

Across all Contracting Parties of the Energy Community, coal-fired power generation and cross-border interconnection capacities represent around 30 GW and 20 GW[13], respectively, of existing infrastructure in 2020, and as such they are the main existing flexibility sources. Hydropower, present in almost all CPs, and gas-fired power generation, mostly present in Ukraine, represent another important category of contributors with installed capacity of around 12 GW and 8 GW, respectively.

All existing interconnection capacities are expected to remain by 2030 and 2040. Figure 5 indicates the transmission network capacities between Contracting Parties and neighbouring countries. The NTCs of Ukraine and Serbia are the most significant ones.

Figure 5 NTC split among Energy Community Contracting Parties

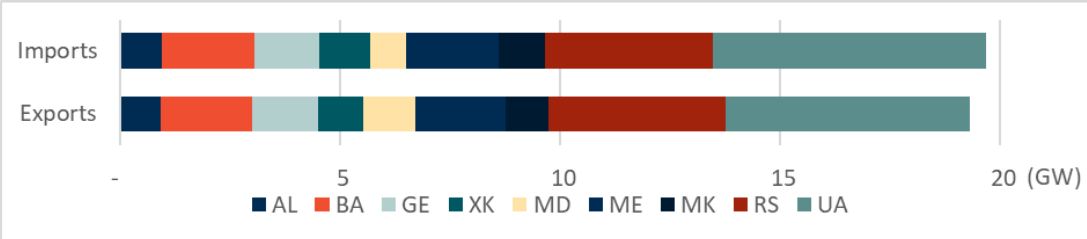
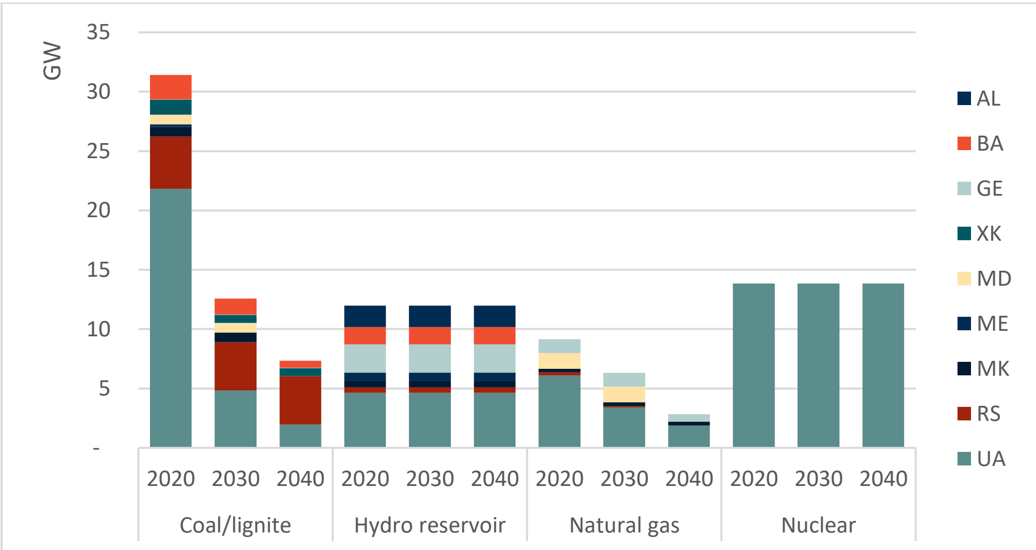


Figure 6 Evolution of existing flexibility solutions in the CPs[14]



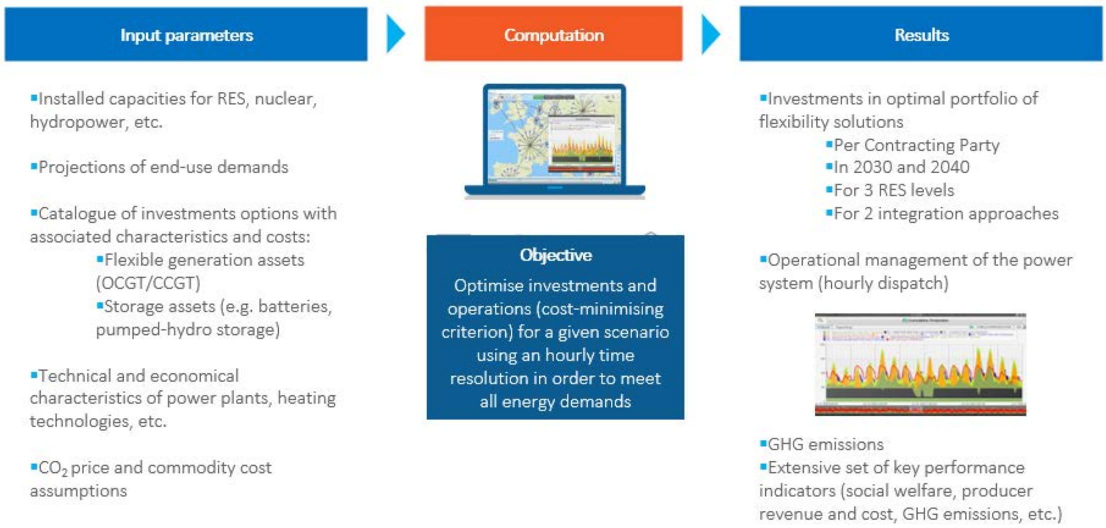
Significant reductions in coal/lignite and gas-fired generation capacities can be expected in the Energy Community by the year 2030 and 2040 as existing assets reach their end of technical life, or will be phased out due to national coal/lignite phase-out strategies in selected CPs as depicted in Figure 6. By 2040, 74% of 2020's coal/lignite power generation capacities and 79% of gas-fired power plants are expected to be decommissioned according to the scenarios.

[13] Sum of the Net Transfer Capacity (NTC) of interconnections over all borders of the 9 CPs.
[14] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community

Modelling a cost-optimal flexibility portfolio

In order to determine the cost-optimal flexibility portfolios for each CP in 2030, 2040, the energy system model *Artelys Crystal Super Grid*[15] was used. The modelling exercise was performed via a joint optimisation of the flexibility portfolio and its operations for the different scenarios, with an hourly time resolution and a country single node representation[16]. Eight CPs were modelled jointly with the EU Member States (MSs), whereas Georgia was modelled independently as an electric island with partial interconnection with its neighbouring countries (with exchanges exogenously set). The main assumptions and outputs of the model are summarized in Figure 7.

Figure 7 Overview of main input and output parameters of Artelys Crystal Super Grid



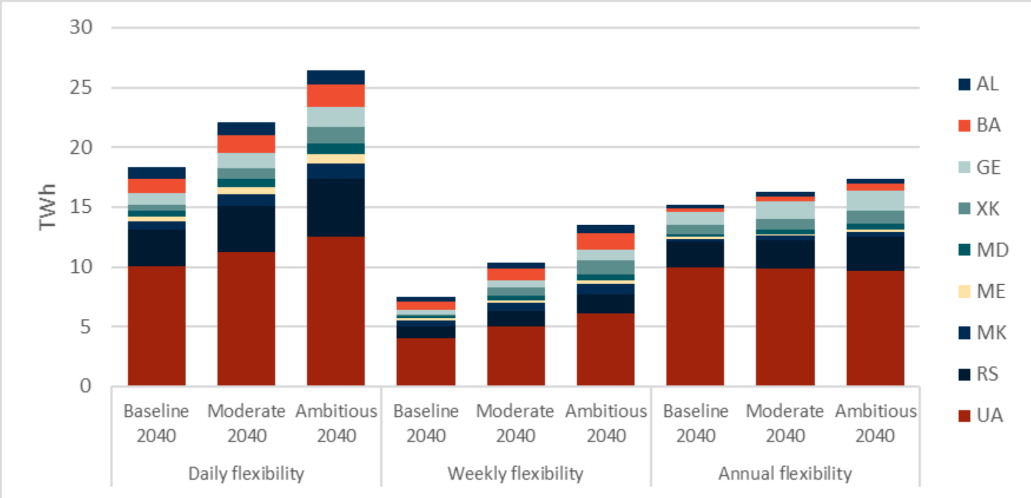
3.2 Main results from the power system modelling

Flexibility needs in the Energy Community driven by vRES uptake

The evolution of the CPs' energy systems (especially the high penetration of vRES, but also the change in the demand level) imply changes in flexibility needs. Flexibility needs are a metric that captures the dynamics of the residual load (calculated as the hourly demand less the variable RES generation), on daily, weekly and seasonal timescales[17]. Aggregated flexibility needs across all CPs increase from 2030 to 2040 due to the increase of vRES. They increase differently across scenarios (from Baseline to Ambitious) as depicted in Figure 8 for 2040. Flexibility needs increase is more important for daily and weekly timescales, driven by solar and wind uptake respectively. Annual flexibility needs rise to a lesser extent.

[15] For further information see: https://www.artelys.com/crystal/super-grid/
[16] This means that all assets of a country's power system (supply, storage and demand) are aggregated in a single point. Thus, no representation of the transmission and distribution grid inside the country is considered.
[17] Infra-hourly flexibility needs are not considered in this study.

Figure 8 Aggregated flexibility needs in the Energy Community per scenario in 2040



Optimal flexibility solutions in the Contracting Parties

Three main conclusions can be drawn from the model-based analysis of the different scenarios:

- ✓ There is no need for investments in additional flexibility capacities by 2030 in any of the analysed scenarios. The existing capacities that provide system flexibilities, namely cross-border interconnections (enabling increasing imports[18]), gas-fuelled power plants and storage assets (including reservoir hydro), but also other thermal power plants can cope with the rising flexibility needs related to an increasing degree of vRES deployment, even in the Ambitious scenario. In CPs with coal and lignite capacities, they continue to represent a relevant share in total power generation, and together with hydropower and interconnections can provide additional flexibility (even in the 'Fragmented Market' scenario with limited cross-border market integration).

- ✓ There is a need for additional investments in new flexibility solutions in 2040, as shown in Figure 9. Given the coal and lignite phase-out envisioned in almost all CPs by 2040, interconnection capacities become the main provider of flexibility at the CP level, allowing to mutualise flexibility resources among CPs and with EU MSs. Storage capacities are relevant in CPs where the vRES shares are highest (Montenegro, Kosovo* and North Macedonia) while gas-fired power generation assets are particularly necessary in CPs that lack power generation capacities to meet their national demand (Ukraine, Moldova, Serbia, Kosovo*, Georgia by 2040). In the Ambitious scenario, investments in the order of 5.7 **billion € to 2040 would be needed,** as shown in Figure 10. Moreover, EVs, through smart charging and V2G, can become a significant contributor of flexibility, although investment costs in technology enabling EV flexibility were not explicitly considered. Investments are not needed to meet the flexibility needs in 2040 in the Baseline scenario.

- ✓ Cross-border integration of power networks and markets decreases the need for investments in flexibility solutions and drives down electricity system costs and CO_2 emissions. Such regional cooperation facilitates vRES integration at lower costs and improves cross-zonal capacity

[18] Increased interconnection capacity can be achieved by additional infrastructure investments, but also via improved market integration, including coordinated net transfer capacity calculation and market coupling. See Recommendations.

allocation between CPs and with neighbouring interconnected EU countries. The impact of market integration on investments on flexibility capacities is depicted in Figure 9 and Figure 10 for the Ambitious 2040 scenario. The total investments for the Ambitious scenario are reduced by 18% in the Market Integration scenario (from 5,73 bn€ to 4,76 bn€). Regional market integration allows, as well, a better integration of renewable generation in the region, reducing curtailment in the area comprised by EnC-CPs and neighbouring EU MSs by 20% (5 TWh in the Ambitious 2040 scenario). This, in turns, allows to reduce CO2 emissions by 19% in 2040, in the Energy Community perimeter (Ambitious scenario, reduction from 13,0 to 10,5 Mton CO2).

The detailed reports for Tasks 2&3 underpins these main conclusions with more detailed information about the individual CPs.

Figure 9 Additional flexibility capacities required in the Energy Community for the Ambitious 2040 scenario. Comparison between Fragmented Market and Integrated Market configurations.

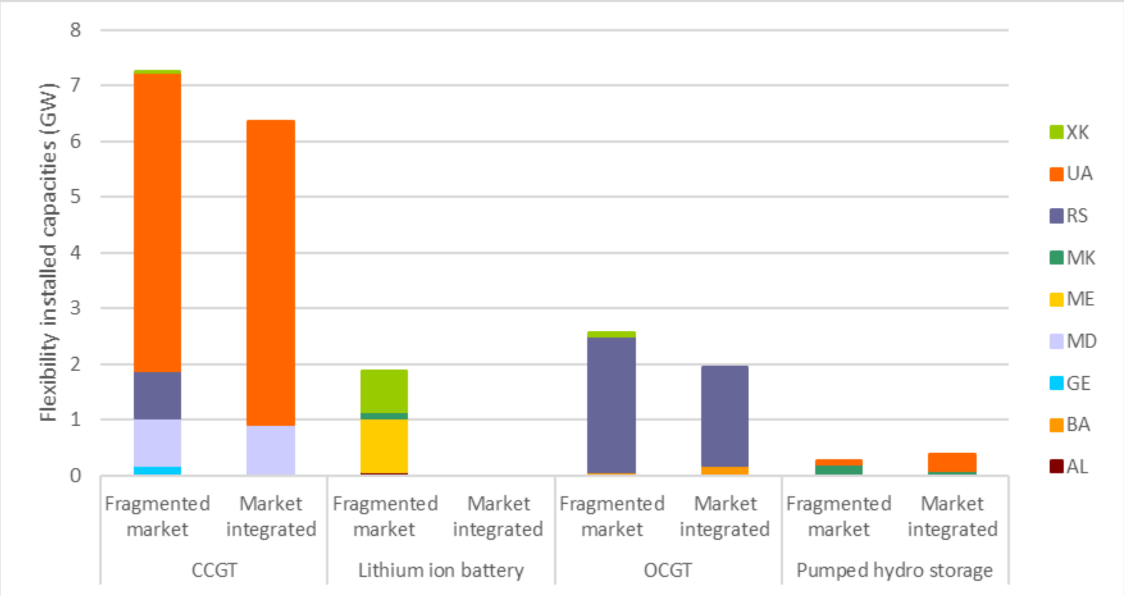
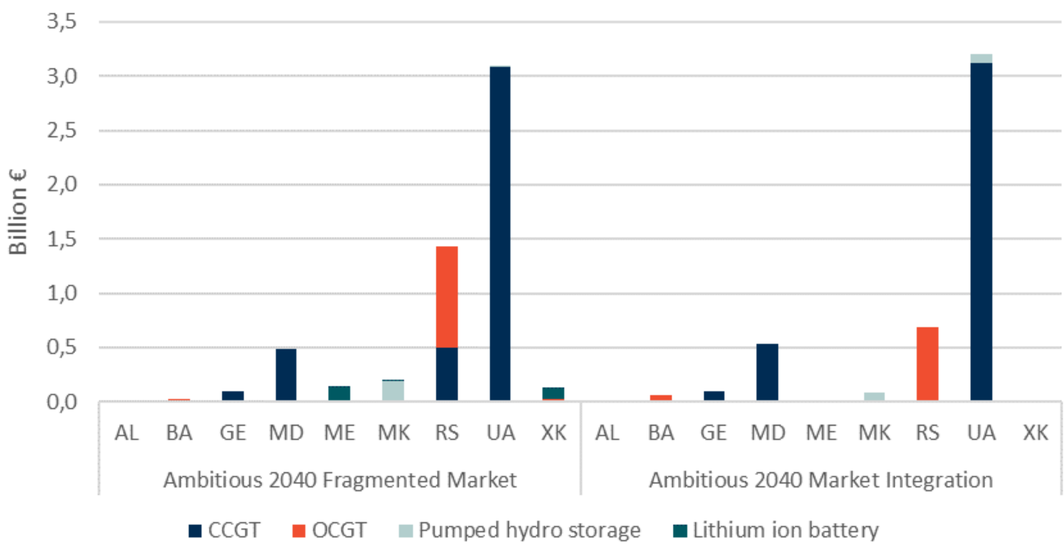


Figure 10 Estimated investment in flexibility sources for the Contracting Parties



Note: the figure includes capital expenditures only, not fixed operating costs

Thus, under all scenarios, interconnectors play a significant role as a flexibility solution, by allowing countries (both Contracting Parties and Member States) to share flexibility sources. The analysis also assesses the impact of increased system and market integration (represented by increased interconnectors' capacity to reflect their increased higher availability) on flexibility needs. It finds that market integration decreases the need for flexibility from storage and thermal power generation.

The results have a number of consequences for the policy and regulatory recommendations to the Contracting Parties developed in this study and presented in the next chapter:

- Wholesale electricity markets' design and functioning will be critical to provide a level playing field for flexibility sources: With the exception of EVs, all main flexibility sources will be large-scale front-of-the-meter ones directly participating in electricity markets. The provision of a level playing field in all electricity markets, including procurement of balancing capacity and energy by TSOs and between TSOs, will be key to incentivising existing sources to provide flexibility, and also important to incentivise investments in specific technologies in certain Contracting Parties;
- Day-ahead and intraday market coupling between Contracting Parties and with the EU will play a large role in enabling the sharing of flexibility sources and optimising the use of interconnection capacity: In addition to national flexibility sources, interconnectors will play a crucial role in the exchange of flexibility, with Contracting Parties being (with some exceptions) net importers of flexibility originating from the EU. Cross-border exchanges will substantially reduce the required reserve and flexible capacity and reduce system costs;
- Retail market design and the provision of adequate price signals to demand response and prosumers (through both electricity prices and network tariffs) will likely be less important from a flexibility perspective. Nonetheless, the contributions to reducing flexibility needs and incentivising the participation of demand side flexibility in electricity markets remain relevant. Electric vehicle smart charging and vehicle-to-grid do appear as a significant flexibility source in the results, even if actual deployment of smart/V2G-enabled EVs to 2040 in the Contracting Parties is uncertain. Other demand-side assets such as industrial assets, heat pumps and electrolysers were not modelled; however, they could therefore play a role to reducing flexibility needs and actively providing flexibility by 2040;
- The introduction of carbon pricing with the gradual phase-out of free CO_2 emissions allowances as well as of subsidies to coal/lignite-based generation are necessary in order to remove entry barriers to new flexibility sources, such as Li-ion batteries, pumped hydro and also gas-fired power generation;
- It is expected that additional flexibility sources will arise due to intra-hourly flexibility needs, which would increase the importance of measures for creating a liquid balancing market integrated between CPs and with the EU. Intra-hourly flexibility needs were not assessed. Although many of the flexibility sources identified (such as gas-fired power generation, pumped hydro, Li-ion batteries, and smart charging of EVs/V2G) as well as flexibility sources not modelled are capable of providing intra-hourly flexibility, additional flexible capacity (from the same or new sources) would likely be needed.

4 Recommendations for fostering flexibility sources in the Energy Community

The Energy Community CPs should design and implement technology-neutral policies and measures to incentivise potential investors, owners and operators of flexible assets to participate in the electricity spot and balancing markets in order to cover the system flexibility needs at least cost. This chapter aims to provide recommendations for improving the legal, regulatory and institutional frameworks to enable 1) the efficient utilisation of flexibility sources and 2) develop additional flexibility sources in order to cost-efficiently meet future needs while assuring security of supply standards in the Energy Community. First, the study identifies the main barriers for the deployment and utilisation of flexibility sources in the Energy Community; and, then, provides a policy and regulatory recommendation toolbox for fostering flexibility sources in the Energy Community.

4.1 Barriers to flexibility sources

The analysis found a number of barriers hindering the optimal deployment and utilisation of flexibility sources:

- Lack of clear guidance on energy & climate policies and targets as well as of strategies for the development of flexibility remains a barrier. While political ambitions regarding RES deployment and phase-out of coal fired power plants are increasing, uncertainty remains regarding the direction and speed of the transition.
- The electricity markets[19] are in general not yet properly functioning in the Energy Community. The lack of liquid, integrated spot (day-ahead, intraday) and balancing markets in most Contracting Parties hinders market access, in particular for new and small flexibility services providers, and hence leads to higher overall electricity system costs. Further, currently spot markets are integrated only with explicit capacity allocation, there is limited exchange of balancing energy, and TSOs do not procure ancillary services yet (e.g. balancing capacity and energy) through cross-border auctions.
- While the ratio of nominal interconnector capacity versus domestic power generation capacity for Contracting Parties is in general higher than for many EU Member States, its availability for trading purposes is low, among others due to congestions in national transmission networks. At present, a high share of the interconnection capacity is unused due to different reasons which are out of scope of this report; the remaining capacity made available to the market is hence low and reduces the possibility of cross-border trade of flexibility.
- Electricity markets present significant entry barriers for flexibility sources, such as due to inadequate pre-qualification requirements for energy markets, untargeted[20] retail price regulation or wholesale/retail market concentration. Generally, retail electricity markets are still highly concentrated, with few suppliers to choose from and with regulated prices in several CPs, and no large-scale roll out of smart meters. This hampers the development of a competitive retail market and the active market participation of retail consumers and prosumers via means including storage and demand response, and other forms of demand side flexibility. The policies and markets do not yet provide adequate incentives (e.g. economic signals via market based electricity prices and time-of-use network tariffs) and instruments

[19] Wholesale and retail energy markets, capacity mechanisms (when necessary) and/or ancillary services markets
[20] That is, blanket regulation of prices to a broad range of consumers and not only to vulnerable consumers

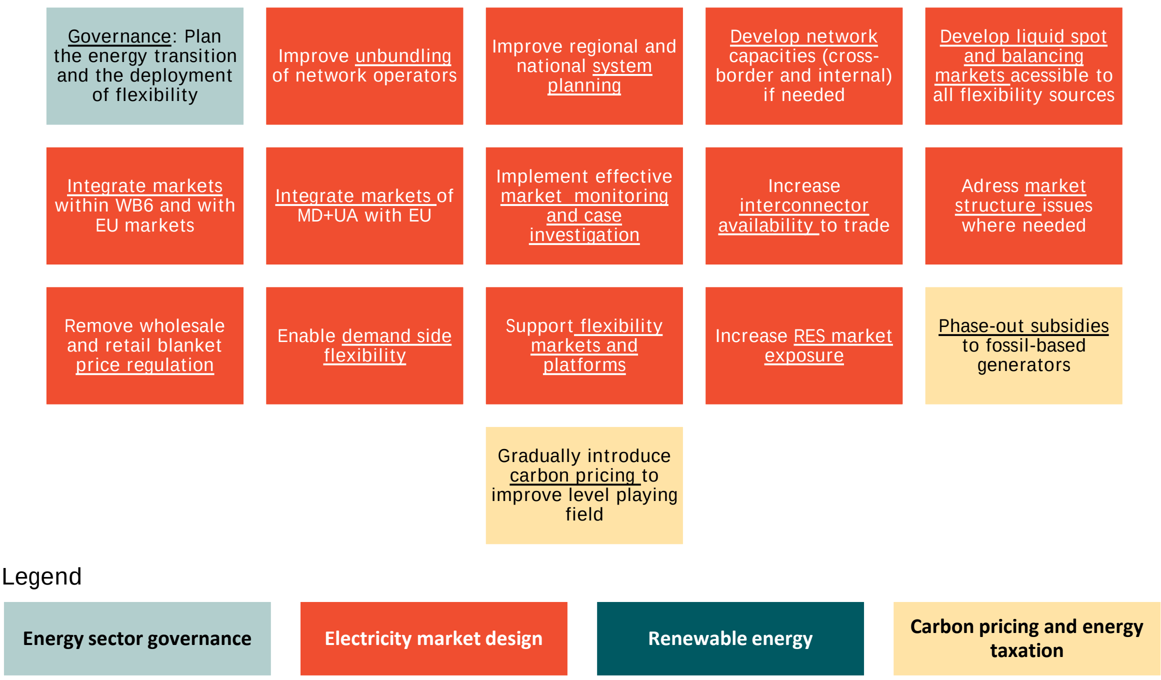
(e.g. smart meters, access to markets via aggregators) for the development of distributed flexibility.

- Other barriers, particularly subsidies for coal fired power generation (including through coal/lignite mining subsidies) and administratively-set (i.e. not market-based) support for renewable energy based electricity further reduce the competitiveness of non-subsidised flexibility sources by distorting the market and ultimately leading to an inefficient selection of flexibility options. Energy taxes and levies may also provide inadequate signals to energy consumption and unduly burden flexibility sources (e.g. due to double taxation applicable to energy storage).

4.2 Policy and regulatory recommendation toolbox for fostering flexibility sources

The study developed a set of policy and regulatory recommendations for fostering flexibility sources in the Contracting Parties. While there are differences in the individual regulatory frameworks, electricity systems and flexibility needs of the Contracting Parties, the EU energy acquis presents the blueprint for providing a level playing field for flexibility solutions across the Energy Community. Therefore, the study presents a set of measures which every Contracting Party should implement, with the EU acquis as a basis.

Figure 11 Overview of recommendations for fostering flexibility sources



The figure above presents the main cross-Contracting Party recommendations for fostering flexibility sources. These are robust and no-regret recommendations such that, independent of the level of renewable energy deployment and fossil fuel-based power generation phase-out, the measures should bring overall societal benefits and facilitate the deployment and efficient utilisation of flexibility sources. As can be seen, the majority of the recommendations relate to electricity market design aspects (which here include system planning aspects). As such, a main priority of Contracting Parties should be the creation of organised spot (day-ahead and intra-day) markets. Competitive (and cross-border where appropriate) procurement of ancillary services including balancing and congestion management services through market-based mechanisms as far as possible should complement the creation and integration of liquid spot markets.

4.2.1 Energy sector governance

Appropriate energy sector governance which adequately and holistically considers flexibility is essential to ensure adequate flexibility levels and coordinate the changes across the regulatory framework. Moreover, appropriate governance is a pre-requisite to providing certainty for investors in flexibility sources.

Develop National Energy and Climate Plans and Long-Term Strategies

National Energy and Climate Plans, their associated progress reports as well as Long-Term Strategies are key instruments to define national energy pathways and the required policies and measures to accomplish them. The flexibility needs and fostering of flexibility sources should be addressed especially under the National Energy and Climate Plan dimensions ‘internal energy market’ and ‘energy supply security’.

Develop a strategy on flexibility sources

The planning of policies and measures to foster flexibility sources can be undertaken through energy/electricity sector strategies (or strategies focusing on individual flexibility solution categories such as demand response or storage) in addition to through National Energy and Climate Plans. As strategies are more focused than overall plans, they may be more appropriate to first identify the necessary policies and measures, which can then be incorporated into NECPs. The flexibility strategy or the NECP may indicate clear targets for the deployment of specific (categories of) flexibility technologies, if appropriate and weighing the advantages of providing these targets vs that of only aiming to provide a level-playing field for all flexibility sources.

Ensure regulatory predictability

Contracting Parties should ensure regulatory predictability to provide adequate signals to investors. This does not mean that regulation should remain unchanged, but rather that any reforms should be consulted with stakeholders in a transparent manner, implemented gradually as far as possible and not unduly affect past investments.

Contracting Parties may implement emergency measures to address some of the effects of the current energy crisis, which is in essence a gas supply crisis that also affects electricity markets. These measures, if ill-designed, may interfere in price signals and market formation.[21] Contracting Parties should be careful when implementing emergency measures (by the regulator or policy makers), as they may impede the development of the electricity market and their integration in line with the Energy Community acquis, reduce cost reflectivity and lead to cross-subsidies[22] in the energy sector, and negatively affect investments, all of which will hinder the deployment and efficient operation of flexibility sources.

[21] ACER (2022) ACER’s Final Assessment of the EU Wholesale Electricity Market Design
[22] Depending on how they are implemented, interventions such as blanket (i.e. not targeted only at protecting a restricted group such as vulnerable consumers) price regulation may represent cross-subsidies from energy producers, suppliers and network operators to end-consumers, negatively affecting cost recovery by the former.

The European Commission has in 2021 provided a toolbox of measures deemed compatible with state aid rules to deal with high energy prices[23] and in 2022 complemented the toolbox with further emergency measures that could be adopted by Member States.[24] These two communications could provide some guidance to Contracting Parties to address the high energy prices with as little distortion of the energy market as possible. However, the need for ensuring regulatory predictability goes beyond the measures taken by Contracting Parties' governments and regulators to address the energy crisis.

4.2.2 Electricity market design

Ensure adequate separation between competitive and regulated activities

TSOs and DSOs have hence an essential role in the deployment of flexibility sources, and compliant unbundling (combined with other measures) is necessary to ensure a non-discriminatory access of flexibility sources to networks. In order to provide their services to other market operators or to TSOs/DSOs, owners/operators of flexibility sources need to have non-discriminatory access to electricity networks and markets. Flexibility sources used to avoid or reduce grid congestion may also be an alternative to grid reinforcement, and should be properly considered by network operators in their network plans. Finally, network operators may incentivise passive flexibility through appropriate tariff designs.

Create and develop organised day-ahead, intra-day and balancing markets

A main priority of Contracting Parties should be the creation of organised spot (day-ahead and intra-day) and balancing markets. Spot and balancing markets will be critical for allowing market participants to adjust their positions in daily, weekly and intra-hourly timeframes considering updated forecasts for renewable energy generation (and also for e.g. demand response assets such as smart-charging EVs which will be relevant flexibility sources in some CPs by 2040), and for system operators to manage residual imbalances. Liquid spot markets should provide the main reference price signals for long-term markets and for investment decisions by flexibility operators relying on these markets for part of their revenues.

Competitive procurement of ancillary services other than balancing and congestion management services (through organised markets where justified) should complement the creation of wholesale markets. The existence and liquidity of such markets and competitive procurement of ancillary and congestion management services are a prerequisite to provide price references as well as the market opportunities for potential flexibility providers to make investment decisions.

Given the current state in the Energy Community where most Contracting Parties do not have such markets in place, the creation of an enabling regulatory framework and adequate rules and procedures, as well as the designation of a nominated electricity market operator (NEMO) should be a point of attention.

Contracting Parties should design organised electricity markets respecting the requirements of the EU electricity market design, such as regarding the removal of price caps, the acceptance of small bids, the possibility for aggregation, minimum and maximum delivery periods, and other aspects. This will not only facilitate the efficient utilisation of existing flexibility sources and provide a positive

[23] https://ec.europa.eu/commission/presscorner/detail/en/IP_21_5204
[24] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3140

environment for the entry of new ones, but also facilitate the integration of electricity markets within the Energy Community and with the EU.

Develop the market-based procurement of non-frequency ancillary and congestion management services

Further progress is needed in the competitive market-based procurement by TSOs of services such as voltage control, black start or islanded operation, and redispatch – both in the EU as well as in the Contracting Parties. This should be combined with real-time publication of system information (RES forecasts, imbalances,…), to guide market parties in their operational decisions.

System operators may also create mechanisms for procuring new ancillary services such as ramping up/down products, synchronous inertia and fast frequency response if and when needed as a result of an increasing penetration of intermittent renewable energy sources and the phase out of fossil-based synchronous generators.

The creation of spot and balancing markets, and the market-based procurement of non-frequency ancillary and congestion management services should provide the main sources of revenue to flexibility sources. Capacity remuneration mechanisms (CRM) may complement revenues, but CRM should only be introduced when duly justified based on an adequacy assessment, and when other means to ensure system adequacy are insufficient. There is however room for mechanisms incentivising innovation and experimentation through pilot projects. These could also facilitate regulatory learning prior to adapting the regulatory framework to remove barriers to entry for flexibility sources.

Address electricity markets concentration and lack of liquidity where needed

The creation of organised markets must be accompanied with the removal of any barriers to entry to those markets which originate from the market structure or other issues and where needed, implementing measures to promote competitive and liquid wholesale electricity markets[25]. National governments and regulatory authorities should conduct an analysis of the current market structure and existing legal and regulatory barriers to entry of new market participants, and adopt the most adequate measures, including measures to address potential market concentration in the provision of ancillary and congestion management services. Further, there is also an important role of the Competition Authority to monitor, investigate and sanction abusive conduct of dominant undertakings.

The transition to a market-based procurement should be preceded by an assessment of the needs on the one hand and the potential service providers on the other hand, and the potential for market abuse. If this assessment indicates insufficient competition for one or several non-frequency ancillary services and for congestion management, regulatory authorities may choose for alternative approaches for non-discriminatory procurement, such as procurement at regulated prices open to all qualified providers, or cost-based mandatory provision. For balancing markets, price limits based on the marginal cost of the most expensive flexibility source may be adopted on a temporary basis to avoid market abuse in the early phases, but should be phased out as they are not compliant with the EU Electricity Target Model.

[25] ECS (2019), POLICY GUIDELINES by the Energy Community Secretariat on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchanges. https://www.energy-community.org/dam/jcr:6bb112a3-526e-4ebf-b265-84d6b392241c/PG_01_2019_ECS_WM_EL.pdf

In order to develop liquid and transparent electricity markets, Contracting Parties should also foresee mechanisms to ensure their integrity and transparency, by transposing and implementing the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT, which in addition to other electricity and gas market segments includes balancing, redispatch and local flexibility markets in its scope).[26] Currently, REMIT is applicable in the Energy Community without the requirement for centralised data reporting. Adoption and implementation of data reporting provisions is expected to be aligned with further integration into the EU day-ahead and intraday coupling regime. .

The market-based procurement of electricity network losses could further contribute to enhancing market liquidity. Several different approaches are possible for procuring power losses, such as requiring TSOs and/or DSOs, suppliers, balancing responsible parties or other market participants to procure or pay for the costs of losses.[27] Promoting the use of non-discriminatory, market-based procedures could incentivise market liquidity, and thus indirectly flexibility sources.

Integrate markets

The integration of Contracting Parties' electricity markets within the Energy Community and with EU Member States[28] will improve the utilisation efficiency of flexibility sources across the region. An important condition for regional market integration is the development of organised national markets, as described in the sub-section above. Contracting Parties should reform their national markets in view of enhancing competition at national level and with the aim of integrating them with the neighbouring markets. The initiatives should focus on coupling of day-ahead, intra-day and balancing markets, with coordinated interconnection capacity calculation and allocation. A particular important step in this regard is the expected adoption of the market and system operation guidelines and network codes by the Energy Community Ministerial Council.[29]

In order to maximise the benefits of market coupling, it will be necessary that TSOs adopt measures to substantially increase the interconnector capacity availability for trade. Implementation of improved methodologies and ICT systems for the identification of critical network elements and calculation of NTCs is recommended, with the objective to move to (preferentially flow-based) coordinated capacity calculation between Contracting Parties, and also between CPs and EU MSs through specific arrangements, until the pan-European capacity calculation and allocation is implemented. The future adoption of the recast Electricity Regulation (EU) 2019/943 and it's 70% interconnector availability target[30] in the Energy Community acquis should provide the high-level framework for these actions.

Enable demand side flexibility

Contracting Parties should ensure that the regulatory framework adequately defines and allows self-consumption as well as active market participation of consumers/prosumers, either directly or via aggregation. Next to this, they should also foster smart metering in the residential and commercial sectors, based on a positive cost-benefit assessment, in order to enable these sectors to effectively

[26] ACER (2021) Guidance on the application of Regulation(EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency
[27] CEER (2020) 2nd CEER Report on Power Losses
[28] The Energy Community Secretariat has developed a proposal to couple markets in the Energy Community and bilaterally between specific Contracting Parties and Member States, in order to arrive finally at an European market coupling. Source: Energy Community Secretariat (2020) Bringing CACM and FCA Guidelines in the Energy Community
[29] 27 th Energy Community Electricity Forum Conclusions. https://www.energy-community.org/dam/jcr:02dce2c2-4b89-4079-a299-db0f10607088/AF_conclusions_0622.pdf
[30] See: Energy Community Secretariat (2021) Electricity interconnection targets in the Energy Community Contracting Parties

provide demand side flexibility. Further efforts could be conducted to identify and activate the industrial demand response potential.

While the modelling results indicate a more limited contributions to flexibility from demand-side resources compared to large-scale solutions, with the notable exception of EVs, the actual contributions in the future could turn out to be more significant. DSOs (in coordination with TSOs) will play a central role in providing signals for (active) consumers to reduce the system's flexibility needs, enable the connection and access to the network for distributed flexibility solutions, and procure their local flexibility needs (e.g. for congestion management) in an objective and non-discriminatory way. The regulatory framework should clearly define these tasks of DSOs, in alignment with the EU Electricity Regulation and Directive.

Phasing out blanket retail price regulation for large and small electricity consumers should be pursued as a priority, both to provide adequate price signals for these consumers as well as to improve the financial stability of regulated companies and suppliers and thus decreasing the need for regulatory intervention in the electricity sector. In order to incentivize demand response, wholesale market based electricity retail price formulas and eventually dynamic (i.e. real-time) electricity priced retail contracts could be promoted (while adequately informing consumers of the risks associated with such tariffs).

Support flexibility markets and platforms

Flexibility markets (where flexibility is exchanged) and platforms (connecting flexibility providers with existing market platforms) are gaining significant attention, especially for the provision of local flexibility (but not only - such platforms could also make contributions at the national, and even regional level). Policymakers and regulators of the contracting Parties could further investigate the potential contributions of such initiatives, create a positive regulatory environment (including with the consideration of regulatory sandboxes if useful) and supporting pilots by various stakeholders (TSOs, DSOs, market operators and third parties).

Improve electricity network planning and operation

TSOs should prioritise the implementation of planned cross-border infrastructure to address the cross-border congestion present for a few interconnectors in the ambitious scenario in 2040. Moreover, coordinated planning will become increasingly important to ensure the integration of energy systems and of flexibility sources across sectors, borders and the transmission and distribution levels.

TSOs should not only prioritise cross-border projects, but also pay close attention the most important internal transmission projects. Addressing some internal constraints could also improve interconnector availability and facilitate the integration of electricity from wind energy parks and solar PV, as well as of flexibility sources. Network investments to modernise grids and address domestic constraints affecting interconnector availability should be undertaken by TSOs whenever these are identified as impacting cross-border availability or integration of RES or flexibility sources at present or in the future.

Developing infrastructure, increasing interconnector availability through coordinated TSO actions, and coupling of markets across different timeframes exhibit important synergies.[31] Therefore, TSOs should take planned market reforms into consideration and coordinate with national authorities and (if applicable) market operators when developing the network development plans. The Energy Community Secretariat could furthermore publish an assessment of the Contracting Parties' network development plans, in order to evaluate issues such as coordination with other national plans (such as NECPs), transparency, inclusion of non-TSO projects, and improved project assessment - as is currently conducted by ACER for EU Member States.[32]

TSOs and DSOs in the Contracting Parties will also need to increasingly coordinate network planning and operation, as the penetration of distributed renewable energy and flexibility sources increases. This will require first of all information exchange in network planning, for example with DSOs providing distributed generation and load forecasts in the relevant planning timeframe to the TSO. Coordination will also be necessary for the connection, pre-qualification and finally access of flexibility sources for the participation in the different markets. DSOs will need to also transparent elaborate network development plans in consultation with stakeholders, in order to ensure that distributions networks are capable of integrating both RES projects and distributed flexibility sources. The distribution network development plans should also consider non-wire alternatives to network expansion.

TSOs should also conduct comprehensive resource adequacy assessments with consideration of the potential of all flexibility sources to contribute to system adequacy. European and if needed national resource adequacy assessments will be central to identifying resource scarcity and the potential contributions of the different flexibility sources. Moreover, once the EU Electricity Regulation is adopted into the Energy Community acquis, TSOs of UA+MD and the Western Balkans 6 as well as the relevant EU and Energy Community authorities should work towards integrating the Contracting Parties' systems into the system operation regions and associated regional coordination centres.

4.2.3 Specific measures and support for renewable electricity generation

Renewable electricity producers can be incentivised to reduce their contribution to the electricity system flexibility needs, as well as to actively provide flexibility services (such as downward balancing or re-dispatching) when possible. Such incentivisation measures comprise adequate support scheme design[33], phasing out of net metering / billing, and phasing out of priority dispatch. These measures need to be well-assessed and weighed against potential negative impacts on the achievement of the renewable energy targets of the Contracting Parties.

Renewable energy producers should increasingly be responsible for managing their own primary imbalances. It is important also that liquid intraday and balancing markets exist and allow the entry of renewable energy producer and that transparent non-discriminatory procedures for balancing markets as well as congestion management are in place.

[31] Kogalniceanu (2020) Projects of Energy Community Interest and Mutual Interest (PECI/PMI) - Legal Background and Process Introduction
[32] See ACER Opinion 05/2021 on the electricity national development plans
[33] Feed-in premiums (fixed or with symmetric/asymmetric sliding premiums) with strike prices defined through auctions should be the default design for supporting large-scale renewable electricity projects. Feed-in premiums determined via competitive auctions are a better alternative than feed-in tariffs fixed by authorities.

4.2.4 Carbon pricing and energy taxation

While it does not affect non-fossil flexibility sources directly, carbon pricing should serve to internalise the negative external costs of fossil-based generation, improving the level playing field for other flexibility sources which will compete in spot and ancillary services markets. The Carbon Pricing study[34] analysed options for the introduction of a carbon pricing mechanisms in the Contracting Parties, favouring the gradual introduction of such mechanisms combined with the integration of electricity and gas markets, and the subsequent integration of the mechanisms with the EU ETS. The study also recommended that Contracting Parties bring taxation rates on energy carriers to similar levels as in neighbouring EU Member States. These measures are not further detailed here but should be pursued by the Contracting Parties.

Moreover, Contracting Parties should also revise the applicable regulatory frameworks in order to ensure that double taxation of storage does not take place. Moreover, it is important that subsidies to fossil-based power producers (as well as to coal mines) and suppliers are removed – in coordination with the removal of price regulation in all segments of the electricity value chain (especially wholesale and retail markets).

[34] Kantor and E3-Modelling (2021) A carbon pricing design for the Energy Community - Final Report

Study on flexibility options to support decarbonization in the Energy Community

Task 1
Analysis of technical and non-technical sources of flexibility

Trinomics

Artelys
OPTIMIZATION SOLUTIONS

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List of Abbreviations

AC	Alternate current
CACM	Capacity allocation and congestion management
CAES	Compressed air energy storage
CAPEX	Capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined cycle gas turbine
CESEC	Central and South Eastern Europe energy connectivity
CP	Contracting Party
DC	Direct Current
DR	Demand Response
ECRB	Energy Community Regulatory Board
ECS	Energy Community Secretariat
EMS	Energy Management System
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emissions Trading System
EU	European Union
EV	Electric Vehicle
FACTS	Flexible AC transmission system
GHG	Greenhouse Gas
GW	Gigawatt
HRSG	Heat recovery system generator
HVDC	High-voltage direct current
ICT	Information and Communication Technologies
IEA	International Energy Agency
IED	Industrial Emissions Directive
IRENA	International Renewable Energy Agency
JAO	Joint Allocation Office
LCOE	Levelized cost of electricity
LCPD	Large Combustion Plants Directive
MVA	Megavolt amperes
MW	Megawatt
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
OHL	Overhead line
OPEX	Operational expenditure
PHS	Pumped storage hydro
PV	Photovoltaic system
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable energy systems
SEE CAO	Coordinated Auction Office in South East Europe
TRL	Technology Readiness level
TYNDP	Ten-year network development plan
UNFCCC	United Nations Framework Convention on Climate Change
USAID	United States Agency for International Development
VRE	Variable renewable energy

Executive Summary

This report serves to introduce the theory and main concepts related to power system flexibility, as well as set the stage for the overall project analysing the contributions of different options to meet the electricity system flexibility needs of the Energy Community's Contracting Parties in the future. The first aim of this report is therefore to introduce the concept of flexibility, the main drivers for system flexibility needs in the Energy Community, and an overview of flexibility sources. The second aim is to provide a detailed overview of selected flexibility sources.

What is flexibility?

Power system flexibility can be defined as the ability of a "power system to reliably and cost-effectively manage the variability and uncertainty [of supply and demand] across all relevant **timescales"**[1], or due to other causes such as transmission outages. Flexibility sources can be defined as the technical and non-technical solutions which provide or facilitate the provision of flexibility, and thus help to ensure the balancing and proper technical functioning of a power system.

Flexibility sources are in particular essential to operate electricity systems with a high number of non-dispatchable generation points connected to the grid having variable outputs throughout the year. The main purpose of flexibility sources is to contribute to:

- ✓ Facilitating deployment of intermittent RES, and
- ✓ Ensuring system stability and security of supply, while
- ✓ Minimising system costs

Drivers of flexibility needs in the Energy Community

The flexibility needs of the Energy Community Contracting Parties are expected to increase in the future, due to three main reasons:

- ✓ Increased penetration of intermittent renewable energy sources: Given the clean energy transition process, Energy Community Contracting Parties will need to accelerate the phase-out of their carbon-intensive power (and heat) generation facilities, with the projections of the Carbon Pricing Design for the Energy Community study of 2021 point to a significant uptake of RES in total generation as soon as in this decade;
- ✓ Phase out of coal-based power generation: It is expected that a gradual phase out of coal-based generation in the Contracting Parties will take place, at different speeds, and due to a number of factors – especially decarbonisation plans, carbon pricing, and the implementation of the EU Large Combustion Plants Directive and the Industrial Emissions Directive;
- ✓ Potential for disruptions to the energy system: More frequent extreme weather and potential reductions in hydroelectric flows or wind availability due to climate change, as well as any other significant disturbances, could be observed. Moreover, the use of natural gas-based plants for the provision of flexibility could increase the exposure to natural gas supply disruptions or price spikes.

[1] IEA (2018) Status of Power System Transformation 2018 https://iea.blob.core.windows.net/assets/ede9f1f7-282e-4a9b-bc97-a8f07948b63c/Status_of_Power_System_Transformation_2018.pdf

Overview of flexibility sources

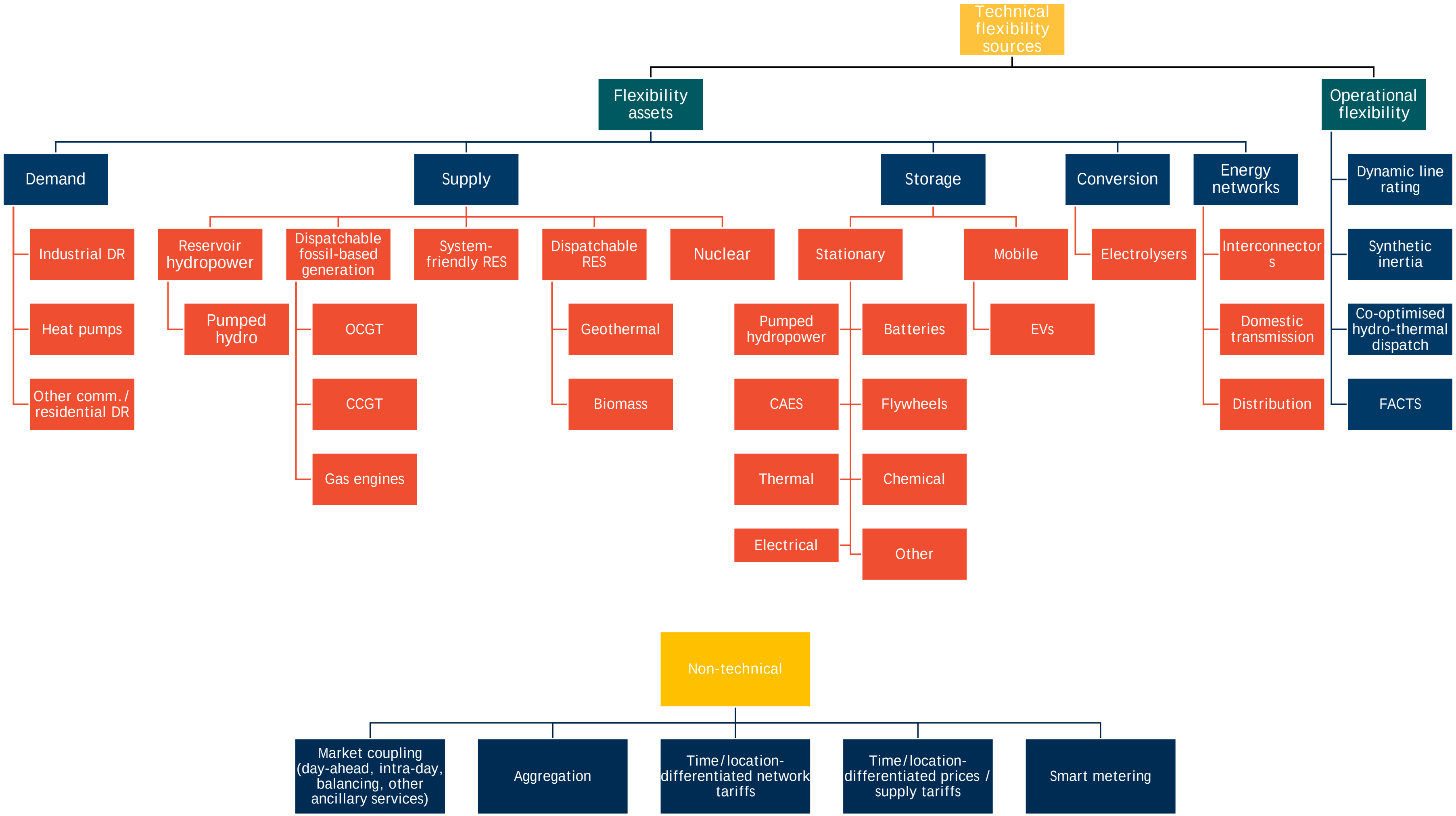
The nature of flexibility sources affects their ability to provide different flexibility services to the power system as well as their economic viability. Flexibility sources can be technical or non-technical. *Technical sources* of flexibility comprise physical flexibility assets (such as dispatchable power plants, demand-response and storage) and *operational flexibility* actions that enhance the effective flexibility capabilities of these physical assets. *Non-technical* sources of flexibility relate to policies and measures which incentivise the availability and use of technical flexibility sources at the transmission and distribution level. The figure below provides a non-exhaustive overview of several technical and non-technical flexibility sources.

Flexibility sources, moreover:

- ✓ Can provide flexibility in specific timeframes, from the intra-hourly to the seasonal. While most sources can provide flexibility in several timeframes, the technical and economic characteristics usually make them more suited for a more restricted range of timeframes;
- ✓ Are characterised by a number of technical characteristics which shape their ability to provide flexibility services in the different timeframes. Some of the most important technical characteristics include the energy and power capacity of the sources, ramping up/down limits, response time and charging/discharging time, as well as the conversion efficiency;
- ✓ The cost of flexibility sources is, along their technical characteristics, pivotal to their ability to provide services to the electricity system. Costs can be broadly categorised as fixed costs (e.g. depreciation and capital costs, overhead costs, fixed O&M costs) and variable (e.g. fuel/electricity, losses, carbon emission and variable O&M costs, ramp-up and ramp-down costs, and start-up/activation costs [2]). In addition to direct costs to the reservation and activation of flexibility sources, there are opportunity costs associated with the provision of flexibility, as well as costs associated with the deployment and maintenance of automated control and ICT systems.

[2] Start-up costs are incurred only once per activation and are thus independent of the actual volume of flexibility provided. However, start-up costs are logically related to the number of activations and thus variable to a certain extent, and these costs will be included in bids of the unit operator. As they influence the short run marginal cost they are here classified as variable, although they are independent of the flexibility volume provided in each run.

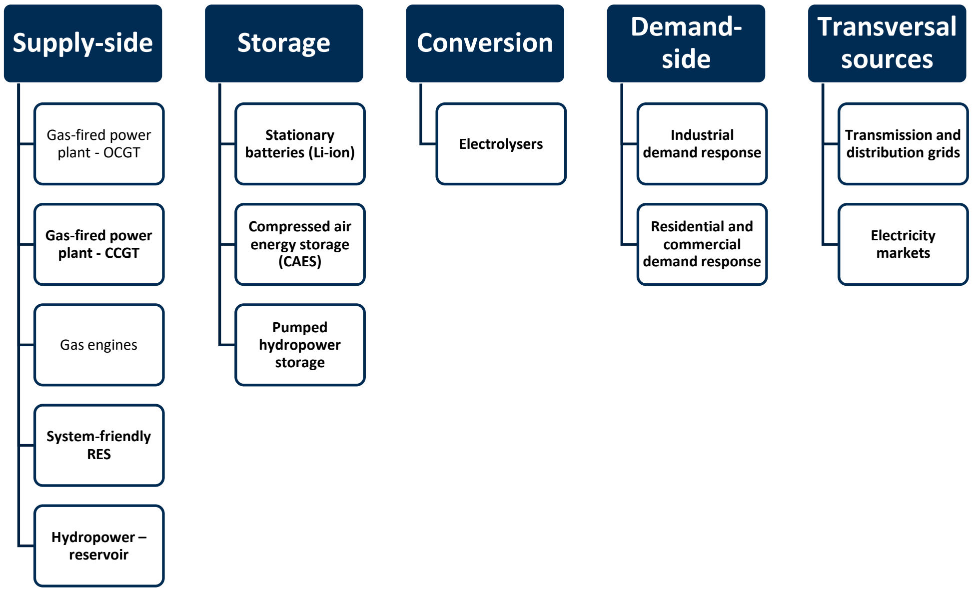
Classification of technical and non-technical flexibility sources with non-exhaustive examples



Characterisation of selected flexibility sources

Starting from a long-list of flexibility sources, a database was developed detailing 13 flexibility sources (shown below) chosen for their significant variation in characteristics such as their location in the electricity value chain, flexibility timeframe, and current and future flexibility potential.

Selected flexibility sources for detailed analysis

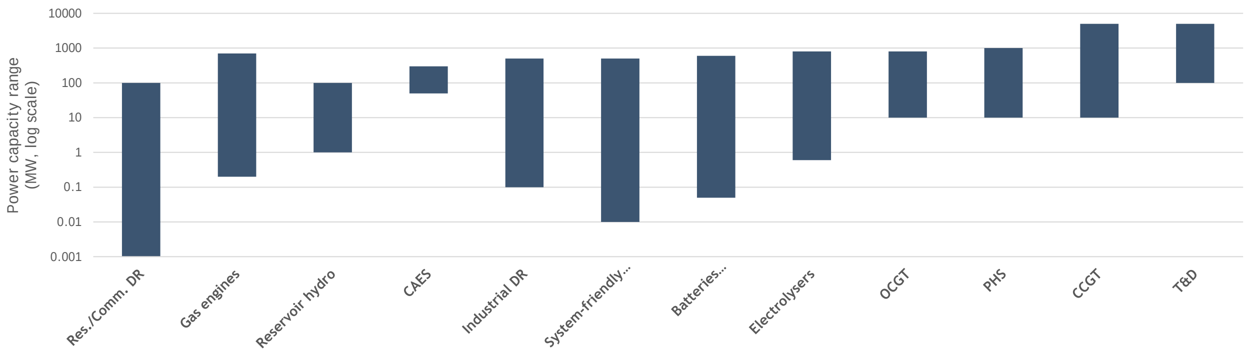


The analysis of the technical characteristics of these sources indicates that:

- ✓ The selected flexibility sources cover, in combination, all flexibility timeframes, from the intra-hourly to the seasonal. However, as several sources are better suited to providing flexibility in certain timeframes, an analysis of flexibility options for the Energy Community has to consider the needs in each timeframe;
- ✓ Revenue stacking (i.e. the combination of different revenue streams of flexibility providers in order to maximise profitability) should be an important strategy to achieve economic viability;
- ✓ The energy capacity[3] of the sources strongly depends on factors not related to technological aspects (such as availability of natural gas), with the notable exception of storage technologies;
- ✓ The power capacity of the flexibility sources (i.e. the maximum energy that can be provided at a certain instant) is more linked to the specific technologies concerned (as opposed to energy capacity, which is more context-dependent as discussed in Section 4) as well as, in the case of aggregated flexibility sources, on the deployment levels;
- ✓ Most of the selected flexibility sources have a high technological maturity (with a technological readiness level close to 9). The exceptions are electrolysers and compressed air energy storage, which show a Technology Readiness Level (TRL) of respectively 8 and 6-9. Despite the high maturity of the surveyed sources, this does not mean that further technological improvements are not needed

[3] Energy capacity and power capacity are further explained in Section 4

Typical maximum and minimum power capacity of selected flexibility sources



Note: Electricity markets are not shown given they do not have an intrinsic power capacity

Source: own elaboration

Flexibility sources have different costs, which are often system-dependent. For the selected flexibility sources, associated fixed and variable costs are collected, although given the system-dependent nature of costs for flexibility provision a comparison between the sources is not straightforward. In general, options focused on changes to system operation and market design tend to be cheaper than new sources of flexibility. Still, changes to system operation and market design do have implementation costs and often require institutional changes.

Best practices for the development and utilisation of flexibility sources

The report collects a number of best practices for the selected flexibility sources. Generally, the analysis indicates that increasing the operational flexibility of assets are best decided on and implemented by the flexibility asset operators themselves. Market operators implement diverse best practices specific to each source to maximise their capability to provide flexibility services.

Policy makers and regulators can design technology-neutral policies and measures to incentivise flexibility provision by the operators of flexible assets and to minimise system flexibility needs to a cost-optimal level. Best practices by policy makers and regulators will be analysed in detail in Tasks 4-5, but common barriers for the deployment and utilisation of flexibility sources can already be identified, and include:

- ✓ Lack of clear guidance on energy & climate polices and targets as well as strategies for the development of flexibility
- ✓ Regulatory frameworks failing to comprehensively address flexibility or certain flexibility source categories (e.g. storage)
- ✓ Safety and environmental rules which are not adapted to the permitting of new flexible technologies
- ✓ Electricity markets[4] are inexistent, incipient or with significant entry barriers for flexibility sources, such as due to inadequate pre-qualification requirements for energy markets, untargeted[5] retail price regulation or wholesale/retail market concentration
- ✓ Limited physical transmission interconnection capacities, limited offering by system operators of those capacities to the market and/or inefficient use of the capacities due to lack of market coupling

[4] Wholesale and retail energy markets, capacity mechanisms (when necessary) and/or ancillary services markets
[5] That is, regulation of prices to a broad range of consumers and not only to vulnerable consumers

- Network planning regulation which does not require TSOs and DSOs to consider non-conventional flexibility solutions nor avoids CAPEX bias
- Network regulation and tariff structures which do not appropriately allocate network and system costs as far as possible to those causing those costs and do not value flexibility sources for avoided system costs
- Energy taxes and levies which provide inadequate signals to energy consumption and unduly burden flexibility sources (e.g. due to double taxation applicable to energy storage)
- Low levels of deployment of residential smart meters and other required measures for smart grids

Deployment status of the selected flexibility sources in the Energy Community

The selected flexibility sources are deployed at different levels in the Energy Community Contracting Parties with some sources yet to be deployed[6]. Deployment of supply side flexibility sources in the Energy Community consists mostly of CCGT and OCGT capacity in a few Contracting Parties. Deployment of storage flexibility sources in the Energy Community is more wide spread, with all Contracting Parties having large and small hydro power in place, adding up to 16.5 GW. Only three countries (Bosnia and Herzegovina, Serbia and Ukraine) have pumped storage hydro available, and North Macedonia is tendering for a new facility. There is limited information regarding the use of demand response flexibility sources in the Energy Community. Projects dealing with automated demand response software/hardware have been identified in Kosovo*, Montenegro, North Macedonia, Serbia and Ukraine. Some experience seems to be available regarding industrial demand response in Montenegro (50 MW provided by the aluminium industry) and in Bosnia and Herzegovina (via the use of the manual frequency restoration reserves - mFRR). Regarding residential and commercial demand response, while there is some EV deployment, there is no indication of smart charging that would allow them to be used as a flexibility source. Pilot projects for EVs in the context of smart grids have been identified in Montenegro, North Macedonia and Ukraine.

Regarding transmission and distribution, all CPs have import/export. According to the ECRB (2020)[7], net transfer capacities did not change significantly in the 2015-2018 period, with eventual changes being due to adjustments in the NTC calculation methodology (with increases being observed for Bosnia and Herzegovina and Montenegro). Cross zonal capacity and their efficient use are yet to benefit from coordinated capacity calculation and market coupling and day-ahead and intraday. Implementation of such reform measures would unlock additional flexibility potential. The reform of electricity markets is ongoing. In terms of enabling flexibility, most work is needed with regards to the wholesale market, in particular short-term segment and regional integration. There is work ongoing for 'reciprocal application of the Regulation on establishing a guideline on capacity allocation and congestion management (CACM)'.[8] Further, some Treaty reforms envisaging reciprocity with Member States and credible enforcement of Energy Community rules, which are relevant to facilitate market coupling projects in the CESEC region are still pending.[9]

[6] System-friendly variable RES; stationary batteries; compressed air energy storage (CAES); and electrolysers.
[7] Energy Community Regulatory Board (2020), Wholesale Electricity Market Monitoring Report for the Energy Community Contracting Parties
[8] Energy Community Secretariat (2020), Annual Implementation Report 2020
[9] Central and South-Eastern European Connectivity (CESEC) High Level Group (2021), Meeting Conclusions - 21 September 2021

1 Introduction and report structure

Objective and scope

The first aim of this report is to introduce the concept of flexibility, the main drivers for system flexibility needs in the Energy Community, and an overview of flexibility sources. The second aim is to provide a detailed overview of selected flexibility sources. Therefore, while in the first chapters flexibility is discussed more broadly, the report focuses on the following flexibility sources:

Figure 1-1 Flexibility sources selected for this study

Supply-side	Storage	Conversion	Demand-side	Transversal
• Gas-fired power plant - OCGT • Gas engines • Gas-fired power plant - CCGT • System-friendly variable RES	• Stationary batteries and compressed air energy storage (CAES) • Hydro – reservoir and pumped	• Electrolysers	• Industrial demand response • Residential and commercial demand response	• Transmission and distribution grid, including interconnectors • Electricity markets

Structure of this report

The first section of the report comprises a theoretical introduction to system flexibility (chapter 2). This is followed by the main drivers of flexibility needs in the Energy Community (chapter 3) as well as an overview of the types of flexibility sources, including a typology of sources and an explanation of the characteristics for the provision of flexibility to the energy system (chapter 4). Chapter 5 provides an in-depth characterisation of the selected flexibility sources, including analysis and comparison e.g. regarding technical and economic characteristics, status of deployment in the Contracting Parties, and a short overview of best practices.

Methodology

The approach for the study is differentiated according to the two main blocks of chapters:

- ✓ The theoretical overview of flexibility and flexibility sources of chapters 2-4 is based on a literature review as well as use of the expert knowledge of the project team. The main aim is to provide a comprehensive introduction to flexibility in the electricity and energy system more broadly, providing the theoretical basis for the remaining chapters of the report and overall study;
- ✓ The analysis of selected flexibility sources of chapter 5 is centred on the development of an Excel database characterising selected flexibility sources[10] regarding their economic and technical characteristics, best practices for the deployment and utilisation of specific flexibility capabilities, and current status of deployment in the Energy Community. Chapter 5 presents a comparative analysis of these aspects, focusing on the most relevant ones.

[10] A total of 12 flexibility sources are characterised. The selection of sources was based on a literature review of existing or potential deployment in the Energy Community for provision of flexibility services, and the short-listing of sources for characterisation in agreement with the Energy Community Secretariat. The list is not exhaustive and does not constitute a judgement on the potential for provision of flexibility to the Contracting Parties by sources not selected.

2 Electricity system flexibility

2.1 What is flexibility?

Flexibility can be defined as "the ability of all power system resources, including generation, storage, interconnectors, and demand-response, to adjust the electricity output and consumption to maintain nominal frequency at all times".[11] The IEA[12] provides a similar definition, where power system flexibility is the "ability of a power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales." To this definition, the ability to reliably and cost-effectively address other unforeseen events (such as transmission outages) could be included also as flexibility.

Degefa et al.[13] indicate that flexibility is "*the ability of power system operation, power system assets, loads, energy storage assets and generators, to change or modify their routine operation for a limited duration, and responding to external service request signals, without inducing unplanned disruptions*". Based on this definition three key aspects are important when considering flexibility sources: (1) the type of source; (2) the timeframe for flexibility provision and the (3) incentive for the reservation and/or activation of flexibility.

This brief overview illustrates that there are different possible definitions of flexibility, focusing on different aspects. For practical purposes of this project, the definition of the IEA can be employed, bearing in mind that it should take into account all aspects that negatively affect the balancing and technical stability of the electricity system (and not only those related to supply and demand).

Flexibility sources can be defined as *the technical and non-technical solutions which provide or facilitate the provision of flexibility, and thus help to ensure the balance and proper technical functioning of a power system*. Following this typology, different types of flexibility sources can be identified both on the electricity supply and demand side (load, generation) as well as other parts of the energy value chain, such as energy storage, conversion, transmission (including interconnections) and distribution.

A distinction can be made between implicit and explicit flexibility incentives, a characterization mostly applied to demand-side measures but which can be interpreted more broadly. *Explicit incentives* on the one hand comprise a financial remuneration by network operators or market parties to the flexibility provider, following the sales of dispatchable flexibility on different markets (such as intra-day and balancing markets) or procurement through other mechanisms. *Implicit flexibility incentives* on the other hand comprise appropriate signals to energy consumers (and other market parties) to take investment and operational decisions which reduce flexibility needs of the system and thus overall system costs. This could include for example energy consumers reacting to time-of-use grid tariffs and/or dynamic commodity price signals and adapting their behaviour through automated processes or personal choices to shift their load. In some cases, such demand response can result in primary energy consumption savings[14]. Besides dynamic retail prices, other time-differentiated or location-based price

[11] As defined in the Terms of Reference of the study
[12] IEA (2018) Status of Power System Transformation 2018 https://iea.blob.core.windows.net/assets/ede9f1f7-282e-4a9b-bc97-a8f07948b63c/Status_of_Power_System_Transformation_2018.pdf
[13] Degefa et al. (2021): Comprehensive classifications and characterisations of power system flexibility resources
[14] https://www.smarten.eu/wp-content/uploads/2016/09/SEDC-Position-paper-Explicit-and-Implicit-DR-September-2016.pdf

signals can also be understood as implicit incentives. Implicit flexibility incentives can also apply to supply-side assets - an example for this would be location-based connection and/or injection fees for conventional or renewable energy based power generation, in order to incentivise the siting of new power generation facilities in the most suitable locations, also taken into account the electricity system constraints.

2.2 Main contributions of flexibility sources

Flexibility sources are essential to operate modern electricity systems, in order to cope on the one hand with the variable load, and on the other hand with the increasing number of non-dispatchable decentralised generation facilities (mainly solar and wind energy) connected to the transmission and distribution grids, with variable and not highly predictable outputs throughout the year. The main advantages of flexibility sources are:

- ✓ Facilitating deployment of intermittent RES, and
- ✓ Ensuring system stability and security of supply, while
- ✓ Minimising system costs

According to IRENA's REmap roadmap, renewable energy sources could cover two-thirds of our total primary energy supply globally by 2050. The development of renewable energy will be coupled with large-scale electrification of different end-use sectors worldwide.[15] Driven by energy and climate policies, rapidly decreasing costs and increasing electricity prices, renewable electricity sources are overtaking fossil power plants in annual deployment and even generation levels in several regions and countries. Chapter 3 details the main drivers for increasing flexibility needs in the Energy Community.

Due to these drivers, it is expected the penetration of distributed renewable electricity generation (mainly wind and solar energy based renewable electricity generation), but also of flexibility sources such as storage facilities and (new) end uses such as electric vehicles and heat pumps at the distribution level will also increase.[16]

Operators of non-dispatchable renewable energy based power plants need access to flexibility sources to balance their portfolio. The variable injection of electricity generated by solar panels and wind turbines into the grid (at transmission and distribution level) is also making it harder for grid operators to balance their network and for DSOs to manage network congestion and ensure the quality of electricity supply; therefore network operators also need access to suitable flexibility sources . Increasing self-production by prosumers is also changing the net demand taken off from the grid with regards to hourly patterns as well as the overall load level. While flexibility sources are thus essential to cope with the increasing variability in the electricity system, they may present opportunities for investors in operators of flexibility sources.

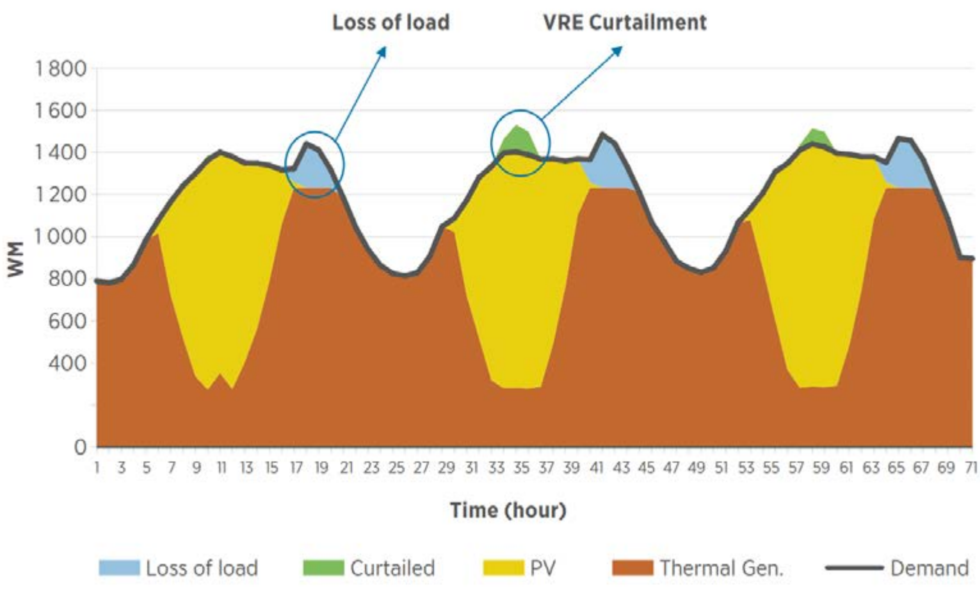
Development of intermittent RES (in particular solar and wind energy) can decrease the electricity wholesale price level, to the extent that they have low variable costs and are in valley hours (where there is low demand and high RES supply, and thus peaking fossil-based power plants are not needed to

[15] Power system flexibility for the energy transition, Part 1: Overview for policy makers (irena.org)
[16] The expected increase in distributed energy resources in the Energy Community is highlighted, among others, in the report of the Energy Community Secretariat (2021) Policy Guidelines on the Grid Integration of Prosumers

match supply and demand) at the margin of the merit order[17], and hence determine the price. Increasing RES penetration also decreases the load factor of conventional power plants that have higher variable costs. These developments can discourage operators to further invest in conventional power generation sources, while these assets are still necessary to ensure system stability. Flexibility sources, including dispatchable power plants, should hence be appropriately remunerated for the flexibility (and back-up capacity) they offer to the electricity system.

Flexibility sources are not only required when there is not enough supply capacity in the system, but also when the overall supply exceeds demand, or when there is congestion in the system. If the supply from RES based power generation and 'must run' facilities (power plants that provide ancillary services or CHPs) exceed demand and/or to avoid grid congestion, system operators may react by curtailing the injection from variable RES as a mitigation measure. VRE curtailment refers to a system operator reducing the output of VRE units to address flexibility issues (related to both system imbalances as well as congestion) [18]. Figure 2-1 shows a mixed load with solar PV and thermal generation supplying the bulk of electricity in the system, where losses of load and the needs for eventual VRE curtailment are clearly visible in peak hours. Curtailment of RES injection can be avoided by flexibility measures, in particular demand response (shift load), which can allow to absorb the temporary local oversupply. Depending on market conditions, flexibility sources could provide trading opportunities in spot markets or be the least-cost solution to balance internally their portfolio

Figure 2-1 Flexibility issues in a system with high penetration of solar PV



Source: IRENA

A further dimension of the challenge is that an increasing share of the installed power generation capacity built to cope with peak demand is facing a decreasing load factor, and may thus become uneconomic – we see a trend of higher peak demand (e.g. in the evenings when residential demand rises) paired with a lower increase in overall energy demand.[19] The related system cost impacts can be

[17] With sufficient penetration and availability of the renewable resource, renewable energy technologies could also set the marginal price at peak hours
[18] Power system flexibility for the energy transition, Part 1: Overview for policy makers (irena.org)
[19] Degefa et al. (2021): Comprehensive classifications and characterisations of power system flexibility resources

minimized with flexibility sources, such as energy storage and demand response which allow to 'stabilise' both demand and supply, by shifting loads.

3 Drivers of flexibility needs in the Energy Community

All Contracting Parties (except Kosovo*) to the Energy Community are signatories to the Paris agreements and thus have committed to reduce their GHG emissions in order to contribute to a climate-resilient future. Some CPs, particularly the Western Balkan 6 (WB6)[20] have indicated the aim to accompany the EU on its net zero path by 2050, as also pledged under the 2020 Sofia Declaration[21]. Fulfilling these commitments will require the gradual decarbonisation of their energy systems, which in many CPs are still reliant on solid fossil fuel-based[22] electricity and heat production.

The decarbonisation of the energy systems of the Contracting Parties will thus rely on a number of measures including energy efficiency efforts, the phase-out of coal-based energy production facilities and the further deployment of renewable energy systems (RES). The expected changes in the power (and heat) generation mix, and thus the impacts of the combination of decommissioning dispatchable (flexible) conventional power generation assets and introducing variable electricity generation sources in terms of flexibility needs will need to be assessed carefully in order to plan for an optimal portfolio of flexibility solutions from a system stability and overall cost perspective.

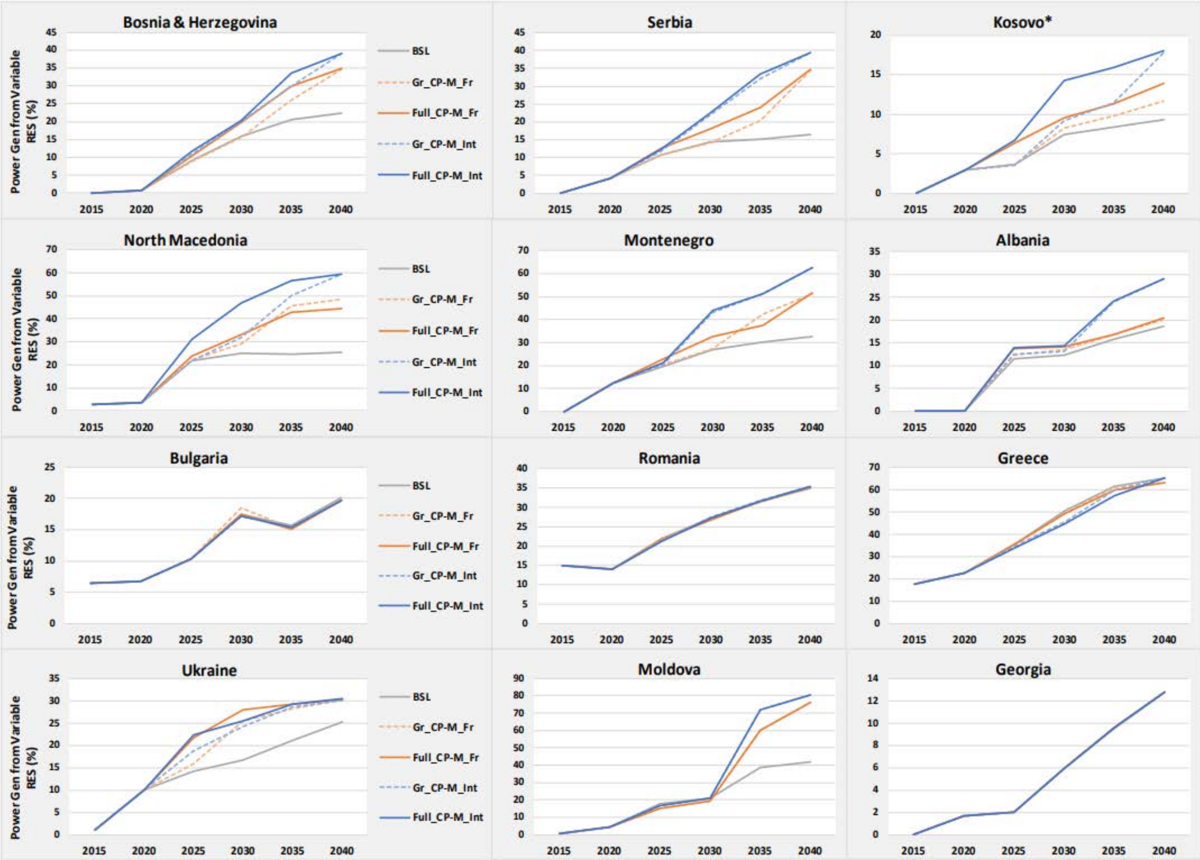
Experience from countries with a high penetration of intermittent RES (including PV installed by prosumers) shows that the demand for flexibility sources is substantially growing. The introduction of variable RES impacts the demand, which has to be met by flexibility solutions. Several flexibility options are available, with different strengths and weaknesses, including dispatchable (flexible) power/heat generation assets, storage options, interconnections with other systems, demand-response, energy conversion (sector coupling), etc. The challenge that all power systems are facing is to build a balanced portfolio of flexibility solutions so as to be able to meet the flexibility needs on all timescales while guaranteeing security of supply.

3.1 Increased penetration of intermittent renewable energy sources

Notwithstanding the lack of formal renewable energy targets in the EnC currently[23], the deployment of renewable electricity has been observed to increase in many Contracting Parties. Given the irreversibility of the clean energy transition process in the coming decades and the prospect of carbon border adjustment mechanisms enforced by the EU, Energy Community Contracting Parties will need to accelerate the phase-out of their carbon-intensive power (and heat) generation facilities in order to reduce their GHG emissions and also be able to keep exporting electricity to the EU. The projections of the Carbon Pricing Design for the Energy Community study of 2021[24] point to a significant uptake of RES in total generation as soon as in the next decade. Figure 3-1 illustrates current and expected volumes of RES deployment in the region:

[20] Six Contracting Parties of the EnC in Southeast Europe: Albania, Bosnia and Herzegovina, Kosovo*, North Macedonia, Montenegro and Serbia forming the 'WB 6 initiative'
[21] https://www.energy-community.org/news/Energy-Community-News/2020/11/11.html
[22] Coal as well as lignite
[23] Annual Implementation report 2020
[24] https://www.energy-community.org/dam/jcr:82a4fc8b-c0b7-44e8-b699-0fd06ca9c74d/Kantor_carbon_012021.pdf

Figure 3-1 Power generation from variable RES in CPs, current and expected deployment



Source: Kantor &E3M, A Carbon pricing design for the Energy Community (2021)

Flexibility is essential to cope with the uncertainty and variability of increased RES that is expected to be deployed in the region, mostly in the form of solar PV and wind sources. In order to be able to properly integrate them into the system while minimising congestion, adequate flexibility sources must be available to balance the system when the output from PV and/or wind is low due to weather patterns. As variable RES-based power generation will increasingly be developed across the CPs of the Energy Community, the national systems will gradually be affected by their impacts on the overall electricity wholesale price levels and on the load factor and profitability of conventional power generation sources.

Small, distributed sources, including decentralised power generation by utilities and end-users (for self-consumption), DR and energy storage (stationary batteries and electric vehicles (EVs)) will probably shape the future electricity system. While EVs are increasing the electricity load, vehicle-to-grid (V2G) mechanisms can help smoothen the load profiles and also provide reserve and flexibility services, similar to stationary batteries[25]. Demand response as well as batteries connected to the grid could make its operation much more complex, having to simultaneously manage eventual congestions, voltage deviations and reverse power flows from prosumers.

[25] Flexibility products and markets: Literature review | Elsevier Enhanced Reader

3.2 Phase-out of coal-based[26] power (and heat) generation

It is expected that a gradual phase out of coal-based generation in the Contracting Parties will take place in the future, at different speeds, and due to a number of factors.

Carbon pricing and decarbonisation targets

The gradual phase-out of coal-based energy and electricity generation in the Contracting Parties is mostly driven by policy evolvements internationally and in the EU. While some CPs have announced decarbonisation targets, the policies and measures leading towards a 2050 decarbonisation are still to be established in the integrated National Energy and Climate Plans. Nationally Determined Contributions under the UNFCCC/ commitments under the Paris agreement could be a good starting point for goal-setting. On the other hand, a regional approach for carbon pricing outlined on the Secretariat's study on Carbon Pricing Design for the Energy Community[27] and future integration in the EU market and EU ETS will further steer developments in the energy sector of CPs on an irreversibly cleaner track. The study shows that carbon pricing would drive decarbonisation significantly after 2030..

Implementation of LCPD (Large Combustion Plants Directive) and IED

While EnC CPs are not participating in the ETS, they are obliged to implement several pieces of EU environmental law via the Energy Community acquis. The Large Combustion Plants Directive (LCPD) sets emission limit values for SO2, NOx and particulate matter for plants with a rated thermal input greater than or equal to 50MW, and thus is applicable to existing coal-fired power plants in the region. The stricter standards of the Industrial Emissions Directive (IED) apply already to new plants and will become applicable for existing ones from 2028 onwards. As most coal plants face significant problems to comply with these directives, the legislation is a strong driver for accelerating the coal phase-out, together with evident decarbonisation trends arising.

Carbon border adjustment mechanism (CBAM)

In order to keep the EU on its track for -55% emissions by 2030, avoid carbon leakage and combat climate change more effectively within its borders, the European Commission proposed to introduce a carbon border adjustment mechanism (CBAM) in the EU in the Fit for 55 Package recently. Next to industrial products, electricity coming from outside the EU will also be subject to surrendering the appropriate number of CBAM certificates by importers based on its carbon contents. Importers will buy carbon certificates corresponding to the carbon price in the EU emission trading scheme at the time of purchase.[28] These rules - if adopted in the EU in the current form - will reduce the profitability of such companies in the CPs who rely on EU electricity exports for revenue. Thus this is a strong driver to phase out coal-based generation in the EnC region and switch to low-carbon alternatives in order to maintain profitable energy flows.

3.3 Need for increased resilience of the energy system

To cope with long-term vulnerabilities, it is crucial that energy systems withstand and resist various types of disruptions, as energy systems are critical infrastructure to the functioning of our economies and daily lives. Resilience to climate change in particular, is indispensable as we see more frequent

[26] Including lignite

[28] https://ec.europa.eu/commission/presscorner/detail/en/qanda_21_3661

changes in weather patterns, varying resource availability and supply shocks worldwide. Extreme weather events can result in serious disruptions, and climate change can reduce hydroelectric flows, as examples. The energy system is vulnerable in different ways at different locations, depending on the climate and specific characteristics of the energy system. An earlier study by Trinomics[29] found the key vulnerabilities of energy systems to be the following:

- ✓ Heating and cooling (H&C) demand will experience significant seasonal shifts;
- ✓ Limited availability of cooling water for thermal power generation;
- ✓ Electricity production will be negatively affected by changes in precipitation, temperature, storm frequencies and intensity;
- ✓ More frequent, extreme weather events will expose primary energy production, transport and storage infrastructure to various risks.

Considering the above, flexibility sources are essential to integrate into conventional energy supply chains for managing these shocks and condition. Another aspect of resilience to consider for the CPs is the fact that with more reliance on gas as a ‘transition fuel (as well as a flexibility source itself), dependence on imports should grow. Recent examples in 2021 of significant prices in gas markets in Europe highlight the importance of resilience against or supply disruptions.

[29] http://trinomics.eu/project/adaptation-of-the-energy-system-to-climate-change/

4 Overview of flexibility sources

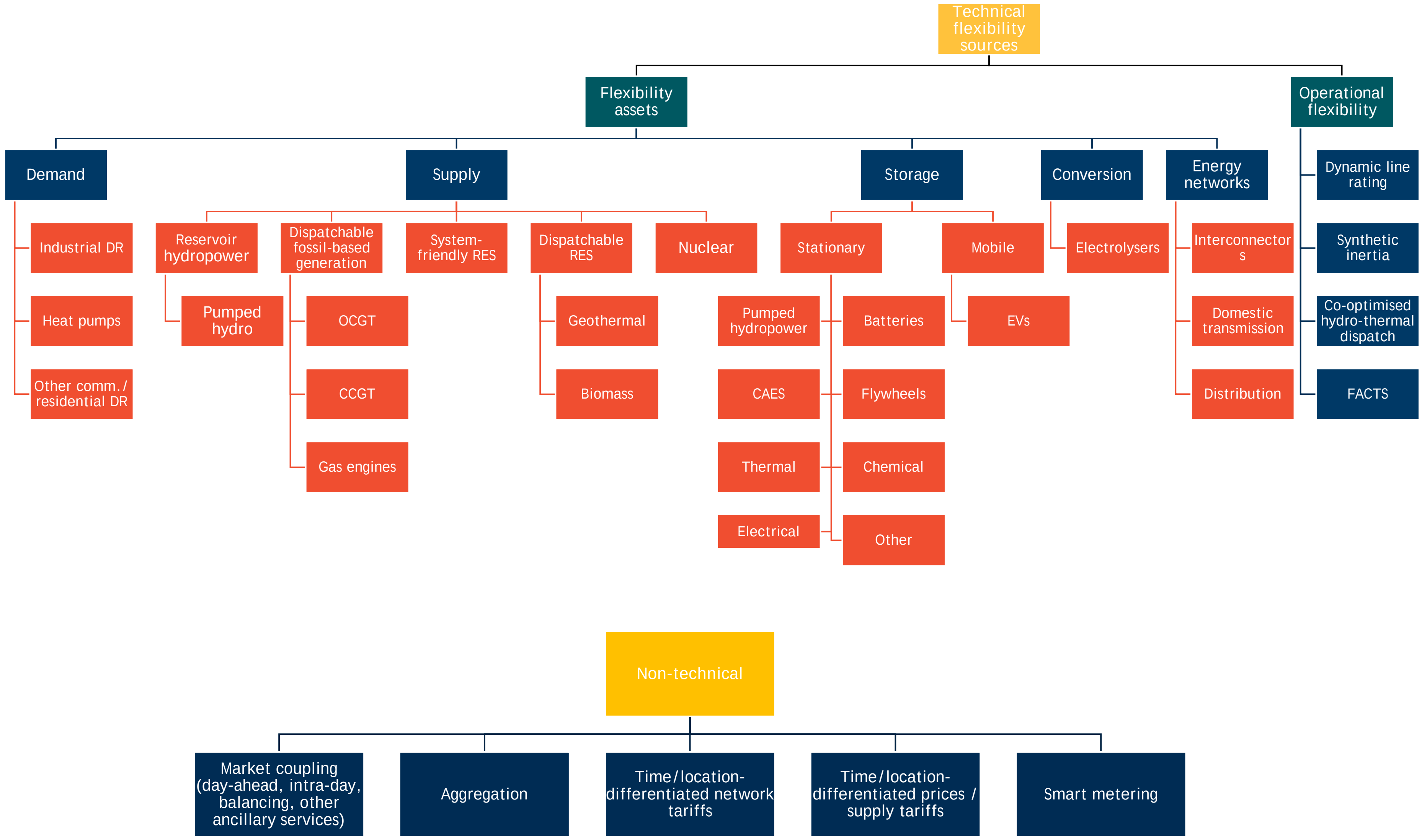
Characteristics of flexibility sources describe their ability to respond to service requests in volume, time, availability and cost. In this chapter we characterize flexibility sources based on their nature (technical / non-technical), the timeframes in which they provide outputs, their costs and other technical characteristics.

Technical (asset and operational flexibility) vs non-technical (i.e. enablers)

We distinguish technical and non-technical flexibility sources, based on their nature. Technical sources of flexibility comprise *physical flexibility assets* (such as dispatchable power plants, demand-response and storage) and *operational flexibility* actions that enhance the effective flexibility capabilities of these physical assets (e.g. dynamic line rating for power transmission lines). *Non-technical* sources of flexibility relate to policies and measures which incentivise the availability and use of technical flexibility sources at the transmission and distribution level, such as the development and improvement of electricity markets for the procurement and remuneration of flexibility services, regulatory requirements for TSOs and DSOs to consider OPEX solutions such as the procurement flexibility sources in an objective non discriminatory way (thus not discriminating CAPEX solutions favourably), or implicit incentives that enable consumers to modify their consumption patterns following price signals.

In Figure 4-1 we present a tree classifying according to this categorisation several potentially available flexibility sources. The figure is non-exhaustive, although it does include some of the most relevant sources for this study.

Figure 4-1 Classification of technical and non-technical flexibility sources with non-exhaustive examples

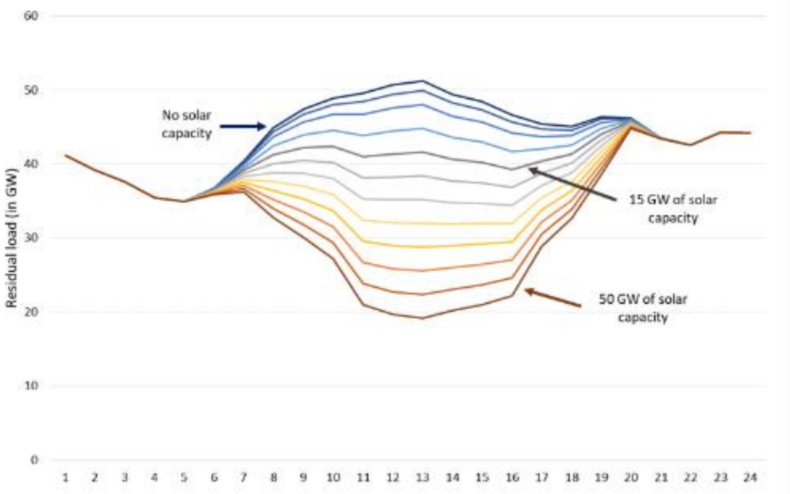


Flexibility provision timeframe

The timeframe for a flexibility service can range from just seconds until up to a few months, depending on the power system needs. Structurally, the large-scale deployment of non-dispatchable RES is associated with an increase of flexibility needs on several timescales. The following aspects are at the centre of the assessment of the need for flexibility in the CPs, demonstrated with the characteristics of solar PV, wind power and other electricity system factors:[30]

- Intra-hourly timescale: Rapid changes in renewable energy generation as well as of demand can require flexibility sources to balance supply and demand very quickly, in the order of (tens of) minutes. Moreover, unplanned supply or network outages can require fast response balancing services, able to ramp up or down in the matter of (mili)seconds to less than 10 minutes;
- Daily timescale: high shares of solar PV drive the need for flexibility solutions that can cycle daily. Demand of households is also cyclical and usually higher during the day (with morning and evening peaks). Dispatchable power generation assets (or other sources such as demand response or storage) have to be operated flexibly to integrate the solar production, with sufficient capacity that can ramp up and down quickly enough to follow the residual load peaks and valleys. Error! Not a valid bookmark self-reference. shows the impact of an increasing share of solar PV on the residual load, where we can see that with increasing PV penetration the daily ramping needs to increase to follow the residual load[31].

Figure 4-2 Impact of an increasing share of solar PV on the residual load



Source: Artelys, "Design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables", 2018

The interplay between the shape of the demand and the deployment of solar PV is important to take into account, as depending on the shape of the demand, low amounts of solar PV can help reduce the need for flexibility by meeting potential demand peaks occurring around midday.

[30] The following description is focused on the contributions of flexibility sources to match supply and demand. In addition, as mentioned flexibility sources can provide contributions to e.g. other ancillary services than balancing (such as black start or voltage control) or to congestion management.
[31] Residual load indicates in a power system how much load is left which needs to be served by dispatchable resources, that is the load left after subtracting for must-run generation and variable renewables.

- Weekly timescale: Power systems exhibit flexibility needs in the weekly timescale due to the weekday-weekend differences in demand levels. This weekly flexibility need is compounded by the deployment of wind power, which is often found to be mostly impacting the need for flexibility on a weekly timescale, since wind regimes can last for several days. There is therefore a need for the flexibility solutions to be able to transfer energy within periods of a few days or between weeks with high and low wind availability or different levels of electricity demand.

- Seasonal timescale: finally, the deployment of variable RES has an impact on the seasonal flexibility needs, as solar PV has a stronger contribution during the summer period while and wind turbines tend to have a stronger output during wintertime. Hydropower availability (especially run-of-river, but also reservoir-based) is also subject to differences in inflows between dry and wet years, which can significantly affect the seasonal flexibility needs from other sources in the Contracting Parties where hydropower is a significant component of the electricity mix. These effects have to be studied together with the thermo-sensitivity of the electricity demand, that differs from country to country, mainly depending on the technologies and energy vectors used for space heating.

Technical characteristics

Flexibility sources differ significantly in their technical attributes and functions. Some sources are limited in their energy or power capacity, while others have lower efficiency or other technical constraints. These characteristics have an impact on their application potential.

The energy capacity of a flexibility source refers to the capability of the source to deliver or store energy, i.e. the maximum energy contents associated with the source[32]. It is either defined by the availability of energy carriers (natural gas, electricity) or the size of the respective system (battery, storage, reservoir). Capacity can be expressed numerically in MWs or MWhs in case of batteries, with sources analysed in this paper ranging from 1 MW capacity to multiple hundreds of GWs.

The power capacity refers to the physical capability of the source to deliver changes in power output to the system, i.e. the amount of flexibility the source can provide, or “power reserve”. For flexibility sources the power capacity can differ based on direction (ramping up or down), and can have a minimum power output for both directions[33]. Power capacity is also expressed in MW and ranges from small projects of a few MWs up to hundreds of GWs, e.g. in case of interconnectors. Ranges of power capacity regarding each flexibility source are presented and visualized in the corresponding Excel document submitted as part of Task 1.

The conversion efficiency of flexibility sources, given as percentage, can be understood as the amount of energy output over energy input. The conversion efficiency of the sources assessed in this study ranges from 35% to more than 90%. For storage technologies, the conversion efficiency incorporates both the charging and discharging cycle efficiencies, i.e. equals to the round-trip efficiency.

Ramping limits (up and/or down), i.e. the ability of a flexibility source to increase or decrease supply or demand, are also extremely important for the intra-hourly to the daily timeframe as the ability of

[32] Comprehensive classifications and characterizations of power system flexibility resources - ScienceDirect
[33] Comprehensive classifications and characterizations of power system flexibility resources - ScienceDirect

flexibility sources to follow changes in the residual load will be one of their most important contributions in a context of increasing penetration of variable renewable energy sources.

Costs for the provision of flexibility

Flexibility products can be procured through the electricity markets (e.g. day-ahead, intra-day and balancing markets) as well as bilaterally by network operators (TSOs, DSOs) and market participants (such as balancing responsible parties). Costs for the reservation and activation of flexibility sources can be categorized as:

- ✓ Fixed, i.e. independent of the volume of flexibility provision (e.g. overhead costs, fixed O&M costs); and
- ✓ Variable, i.e. related to the volume of flexibility provision (such as fuel/electricity, losses, carbon emission and variable O&M costs, ramp-up and ramp-down costs, start-up/activation costs[34]).

The direct cost for the provision of different flexibility services can vary significantly depending on the type of flexibility source, the associated technology and assets, ranging from very low (e.g. residential load shifting) to very high (e.g. in case fossil-based power generation units with high fuel costs are needed in scarcity situations). In additional to such costs, there may be additional costs associated with the development and maintenance of automated control and ICT systems necessary to manage the provision of flexibility (which may be allocated as fixed costs to the flexibility source operator or e.g. socialised).

Moreover, even if costs to reserve and activate the flexibility source are low, there may be opportunity costs associated with the flexibility provision. These may take the form of lost revenues in the case of e.g. need to dispatch wind farms at less than 100% to reserve capacity for flexibility provision, but also may take the form of loss of utility - e.g. lower comfort due to residential heating profiles or EV charging patterns. Generally, the opportunity costs associated with revenues will affect flexibility sources which actively participate in the different electricity markets, while the opportunity costs associated with utility losses will affect residential demand response. Households will provide flexibility through residential demand response in case they are able to either maintain the same level of comfort or are remunerated financially for the loss of utility.

As flexibility sources have different characteristics and also exhibit important differences in their cost structure (e.g. relevance of fixed vs variable cost), opportunity costs as well as in the reservation and activation cost levels, these differences play an important role in the adequacy of each source to provide specific flexibility services (along with technical characteristics and available potential).

Flexibility services capabilities

When broadly defined, there is a wide range of flexibility services to which flexibility sources can contribute to, according to their costs and technical characteristics. It is therefore interesting to briefly mention some of these services and the timeframe on which they are required. We introduce in Figure 4-3 some specific flexibility services (non-exhaustive) that can be required by network operators and market participants, in particular Balancing Responsible Parties (BRPs).

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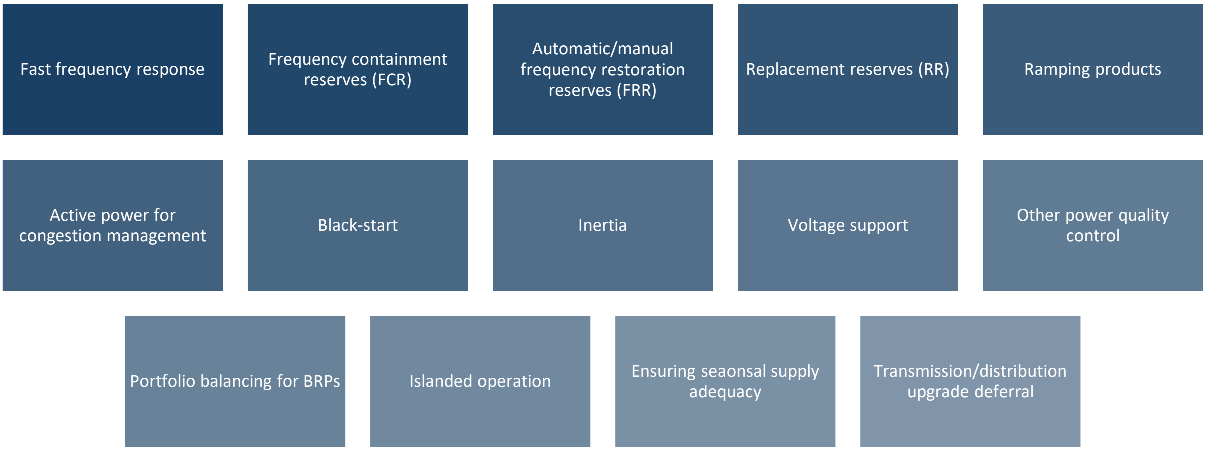
[34] Start-up costs are incurred only once per activation and are thus independent of the actual volume of flexibility provided. However, start-up costs are logically related to the number of activations and thus variable to a certain extent, and these costs will be included in bids of the unit operator. As they influence the short run marginal cost they are here classified as variable, although they are independent of the flexibility volume provided in each run.

Most of these can be classified as *ancillary services*, with the notable exceptions of ensuring supply adequacy, deferring transmission and distribution upgrades, and portfolio balancing for BRPs. However, the large number of flexibility services associated with short-time frames (intra-hourly to daily) does not mean that the need for services with a long-term timeframe will be less relevant, for example in the case of ensuring seasonal supply adequacy.

Figure 4-3 Selected flexibility services



5 Characterisation of selected flexibility sources

This section analyses several flexibility sources in detail in order to provide a comprehensive view of different flexibility sources, their technical and economic characteristics, best practices and current deployment status in the Energy Community.

Starting from a long-list of flexibility sources, 13 flexibility sources (presented in Figure 5-1 and detailed in Table 5-1) are chosen to have variety regarding characteristics such as their location in the electricity value chain (supply/ storage/ transmission and distribution/demand or transversal), flexibility timeframe (intra-hourly/ daily/ weekly/ seasonal), and current and future flexibility potential. It must be noted that the selection does not mean that other sources are not or will not be relevant providers of flexibility in the future, in the Energy Community or elsewhere. Here transmission and distribution grids as well as electricity markets are categorised as transversal because they do not provide flexibility in itself, but allow for the optimal utilisation of other flexibility resources in all parts of the value chain.

Figure 5-1 Selected flexibility sources for detailed analysis

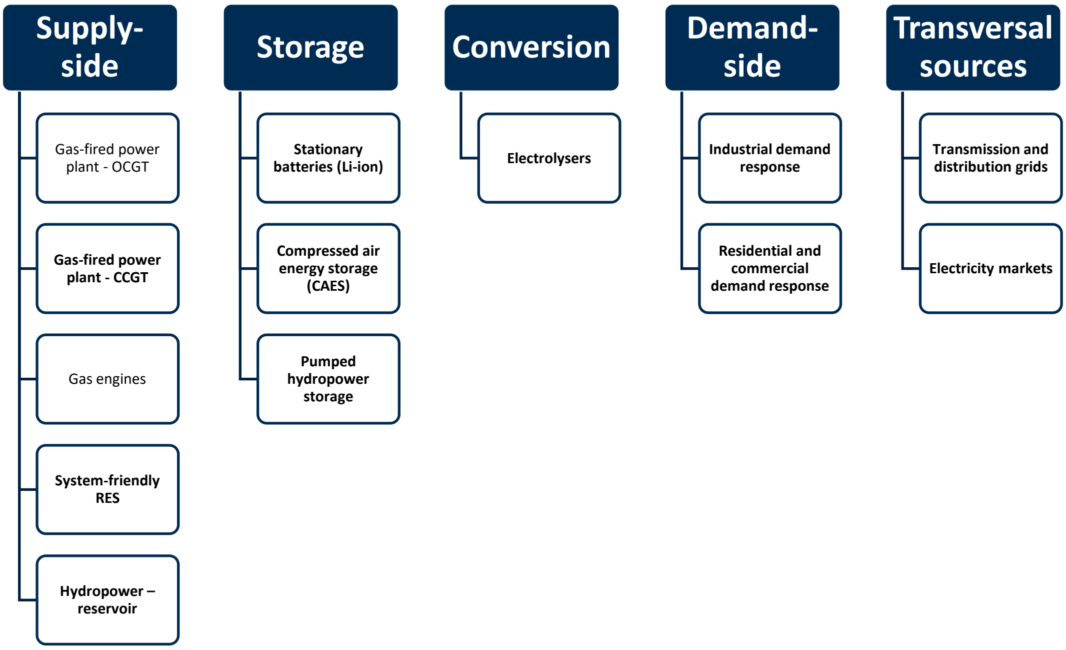


Table 5-1 Selected flexibility sources for characterisation

Category	Flexibility source	
Supply-side	Gas-fired power plant - OCGT	Open-cycle gas turbines (OCGT) are gas-fired turbines which operate a single cycle where compressed air is mixed with natural gas for combustion in a turbine. OCGTs have a lower efficiency than CCGTs but increased responsiveness and flexibility (including for modular operation). OCGTs can offer flexibility especially in the intra-hourly, daily and weekly timeframe. However, in case state-of-the art CCGTs are sufficiently flexible to provide also daily flexibility to a specific system, they may be preferred than OCGTs given the higher efficiency and resulting lower emissions. Albeit being able to provide flexibility in the seasonal timeframe, the lower efficiency makes OCGTs less adequate for this purpose than CCGTs, and also less competitive given lower efficiency and higher emissions.
	Gas-fired power plant - CCGT	Combined-cycle gas turbines (CCGT) combine one or two gas turbine in the first stage with a steam turbine in the second stage (fuelled by a heat recovery steam generator). CCGTs have the highest conversion efficiency between thermal power plants, making it suitable for the provision of baseload power and seasonal/weekly flexibility. State-of-the-art CCGTs have technical characteristics which allow the technology to provide also daily flexibility, although CCGT operation is generally less flexible than OCGTs. Ramp-up/ramp-down limitations makes several plants less suitable for intra-hourly flexibility provision, although new/retrofitted plants with specific design and operational measures to increase flexibility can provide services in the intra-hourly timeframe. Variable costs for CCGTs depend mainly on gas and emission allowances prices, as for OCGTs.
	Gas engines	Gas engines use an internal combustion engine to provide intra-hourly to daily and potentially weekly flexibility. Gas engines are usually combined in a generating set - a group of gas engines connected to the same shaft which drives the electric generator. A engine-based power plant may comprise several gen sets. The fact that gas engine power plants can typically count with tens of units means that it can operate with full efficiency at part load, as individual units can be (de)activated as needed. Gas engine power plants can maintain efficiencies as high as 46-50% at any load level, contrary to combined cycle gas turbines, with individual units operating at full load. Gas engines may be able to accept a number of other fuels, including fuel oil, (bio)diesel and other biofuels. While gas engines can have a higher efficiency and lower NOx emissions at part load than CCGTs, at full load CCGTs are more efficient and have lower NOx emissions. This means that CCGTs are still generally more suited for the provision of long-term flexibility.
	System-friendly RES[35]	System-friendly RES could be defined as measures taken in the design of the RES generating assets, including siting decisions, which provide a more smooth generating profile and/or more aligned to demand profiles.[36] Thus, system-friendly RES *reduce the flexibility needs of the system*. They should also ensure more stable revenues for RES operators by mitigating the decreases in value captured by RES due to the increasing occurrence of low and negative market prices. According to other literature sources, system-friendly RES may be understood as the ability of RES generators to provide ancillary services, especially balancing services[37].
	Hydropower - reservoir	Hydropower (and pumped hydro storage) traditionally have been used to balance demand fluctuations and provide operational reserves. Hydropower is an extremely flexible source, supplying electricity or storing it to meet real-time energy needs, acting as a grid stabilizer. As examples, hydropower can quickly deliver power after an outage, address peak demands and maintain proper voltage levels and frequencies across the grid.[38] Reservoir hydropower use a dam to store natural water inflows in a reservoir for electricity generation when necessary (as opposed to run-of-river hydropower, which does not have a reservoir, or closed-loop pumped storage, which does not have a natural water inflow).
Storage	Stationary batteries (Li-ion)	A Lithium Ion (Li-ion) battery stores energy based on electrochemical charge/discharge reactions taking place between a positive electrode (cathode) and a negative electrode (anode). Deployment of battery storage systems has been developing significantly since 2010, driven both by stationary systems

[35] Different definitions of system-friendly RES can exist - see the discussion below on this issue

[36] See Hirth et al. (2016) System-friendly wind power: How advanced wind turbine design can increase the economic value of electricity generated through wind power. https://www.sciencedirect.com/science/article/pii/S0140988316300317

[37] See NREL (2019) Grid-friendly Renewable - Energy Solar And Wind Participation - In Automatic Generation Control Systems. https://www.nrel.gov/docs/fy19osti/73866.pdf

[38] IRENA (2018) Power System Flexibility for the Energy Transition. Part 1: Overview for Policy Makers

Category	Flexibility source	
		as well as use of Li-ion batteries in electric vehicles. Future technology developments should be focused, among others, in achieving further significant cost reductions, increasing recyclability and battery performance.[39]
	Compressed air energy storage (CAES)	CAES systems store energy as compressed air in a reservoir (such as an underground cavity) , and then generate electricity in a way similar to a gas turbine. To charge a CAES system, a system of compressors store air in the reservoir making use of cheaper excess or off-peak electricity. For discharging, the compressed air is expanded, and if necessary reheated by mixing the compressed air with fuel (e.g. natural gas) in a combustion chamber driving a turbine system.[40] Heat recovered from the compression stage can also be used to re-heat the compressed air, in which case co-firing with natural gas may be unnecessary.
	Pumped hydropower storage	Pumped hydro storage uses, in the charging cycle, electricity in order to pump water from the lower to the higher reservoir. In the discharge cycle the stored water is used to generate electricity. Pumped hydropower may be open-loop (where a connect exists to a natural water flow) or closed-loop (where no such connection exists, i.e. the upper and lower reservoir are not connected/part of lakes or rivers).
Conversion	Electrolysers	Hydrogen generation from electricity in electrolysers may become a significant component of future energy systems. By adapting operation according to system needs and electricity prices, electricity consumption of electrolysers can increase the flexibility of the energy system. Combined with hydrogen storage and hydrogen-based power generation (through fuel cells or hydrogen turbines) electrolysers can provide a number of additional flexibility services to the electricity system.
Demand-side	Industrial demand response Residential and commercial demand response	IRENA[41] defines demand-side flexibility as "a portion of the demand, including that coming from the electrification of other energy sectors (i.e., heat or transport via sector coupling), that could be reduced, increased or shifted in a specific period of time to facilitate the integration of variable RES, reduce peak load and seasonality, and reduce generation costs. Demand response specifically refer to a voluntary (and implicitly or explicitly compensated) load reduction to provide flexibility to the system. Industrial DR can cover power-to-heat, power-to-hydrogen and industrial processes. Residential and commercial demand-response can cover battery EVs, power-to-heat and (smart) domestic appliances, among others.
Transversal sources	Transmission and distribution grids (including interconnectors)	The electricity transmission (including interconnectors) and distribution systems can increase system flexibility in several ways: - Minimising the need for system flexibility: by connecting different regions and types of network users, electricity networks integrated supply and demand with different profiles, thereby (potentially) reducing the correlation between these profiles and thus the variability of the residual load (i.e. the load which remains when intermittent and must-run supply is subtracted, and which needs to be met by dispatchable sources) - Enabling the optimal use of flexibility sources: by enabling (along with market integration measures) the coupling or integration in single zones of different electricity markets (day-ahead, intraday, balancing and eventually flexibility markets) as well as enabling distribution-connected sources to participate in the provision of flexibility services, electricity networks increase the available flexibility sources and enable the use of the least-cost sources.
	Electricity markets, including day-ahead, intraday, balancing, flexibility platforms	Energy markets can contribute to the optimal investment and utilisation of flexibility sources by facilitating the participation of the sources in national electricity markets or by integrating various national markets. Facilitating the entry of new market participants and integrating different national markets can ensure the most cost-effective flexibility sources are used, increase market liquidity and overall competition, and optimise the utilisation of interconnection capacities. Moreover, several stakeholders propose the development of new flexibility platforms for different actors (network operators, but also other stakeholders such as aggregators and balancing responsible parties) to procure flexibility services needed in the different timeframes in specific marketplaces or to serve as an intermediary between flexibility service providers and established wholesale and balancing markets.[42]

[39] European Association for Storage of Energy (s.d.) Technologies. https://ease-storage.eu/energy-storage/technologies/
[40] IRENA (2017) Electricity storage and renewables: Costs and markets to 2030
[41] IRENA (2019), Demand-side Flexibility for Power Sector Transformation. Analytical Brief
[42] Frontier Economics for ENTSO-E (2021) Review of Flexibility Platforms

Box 1 Challenges to system-friendly renewable energy design

As indicated above, several different concepts exist regarding system-friendly renewable energy. The most strict definition is of system friendly RES comprising renewable energy-based power plants whose design of the generating assets, including siting and portfolio diversification decisions, provide a more smooth generating profile and/or more aligned to demand profiles. [43] Traditional examples include wind turbines with a larger rotor-to-generator capacity ratio, or orienting some PV panels east or west.

More broadly, system-friendly RES can be understood as any renewably energy plants which for various reasons either reduce system flexibility needs or are able to participate in the provision of flexibility services. This could include actions such as the on-site combination of renewable energy generation with storage, new operational strategies (such as reserving part of the forecasted generation capacity for provision of upward balancing energy), or enhancing the capability of the renewable generation assets regarding synthetic inertia or fault ride-through (the latter motivated by regulation).

By reflecting supply scarcity and system constraints, well-designed electricity markets should naturally incentivise project developers to design and build system-friendly renewable energy power generating facilities, as developers have an interest in maximising revenues by generating in moments of high electricity prices. But in practice, support schemes may still provide a significant share of a project's revenues (even when exposure to the market is incentivised as in the case of variable feed-in premiums) and their design may not incentivise system-friendly investment and operational decisions. The decision by RES operators to also generate in moments of negative electricity prices is the most extreme example (in order be remunerated through the support schemes that provide operational support irrespective of the market situation), but even if support schemes do not remunerate renewable in moments of negative electricity prices, their design may still not incentivise operators to reduce system flexibility needs to a large extent. Moreover, in order to choose for a system—friendly design, operators need to be able to forecast electricity prices throughout the project lifetime and to accurately predict that revenues would be higher with a system-friendly design than with a 'conventional' design (due to e.g. renewables penetration cannibalising its own revenues in spot markets due to their low variable costs).

Therefore, both due to the need for improvement of electricity markets and support schemes design and the need for RES operators to accurately forecast highly uncertain future electricity prices, insufficient incentives may exist for operators to choose for system-friendly in place of conventional designs.

The Excel database details the flexibility sources and allows their comparison, providing the following information:

- Short description of the source
- Electricity value chain step, listing whether the flexibility source is located at the supply, storage, transmission and distribution or demand steps. Note that certain flexibility sources may be placed at more than one step, as e.g. demand response solutions may include behind-

[43] See May et al. (2015) Market incentives for system-friendly designs of wind turbines. https://www.diw.de/documents/publikationen/73/diw_01.c.507714.de/diw_econ_bull_2015-24-1.pdf

the-meter solar PV generation or home storage systems. Moreover, electricity markets are classified as being transversal, as they enable flexibility sources in all steps of the value chain;

- Flexibility timeframe, meaning the timeframe(s) at which the sources provide flexibility - see chapter 2 for further details on this aspect;
- Energy and power capacity, indicating the capacity for provision of flexibility in energy (for example in GWh/year) and capacity terms (i.e. maximum power in MW achievable by a single unit or a combination of units);
- Conversion efficiency, presenting in percentage the efficiency (energy output / energy input) of the source. Efficiency may take different forms depending on the source (e.g. conversion efficiency from electricity to hydrogen in case of electrolysers, round-trip efficiency in the case of storage solutions, or efficiency in the case of electricity systems);
- Maturity, defined as the technology readiness level of the flexibility solution. Technology readiness levels are a high-level categorisation aiming to indicate where a specific technology stands in a spectrum from basic principles being observed (TRL1) to successful deployment in an operational environment (TRL9).[44]
- Other technical characteristics, describing any relevant technical aspects which may contribute to or constrain the provision of flexibility by the source in question;
- Variable and fixed costs, covering a wide range of cost components such as CAPEX, O&M and fuel costs, including (where available) activation costs for the provision of flexibility. It must be noted that while providing useful information on typical costs for the flexibility sources, the actual cost for the provision of flexibility will depend on each specific energy system characteristics and other factors, as they will influence the operational decisions of flexibility assets. Hence, flexibility provision costs for relevant sources are better analysed in Task 2 and 3;
- Best practices, referring to identified best practices for the deployment of each specific flexibility sources in the Energy Community or in other countries. This may cover various aspects, from technical measures to increase the flexibility capabilities of energy assets to operational processes or legal and regulatory measures to incentivise flexibility provision;
- Deployment status in the Contracting Parties, constituting only a high-level description with the aim to provide a more complete overview of the sources. A more detailed assessment of the actual sources providing flexibility services to the Energy Community Contracting Parties is provided in the report of Task 2 (report upcoming).

5.1 Comparison of technical and economic characteristics

This section compares the technical and economic characteristics of the selected flexibility sources, in order to provide an overview of these characteristics as well as to raise relevant issues related to economic and technical potentials and constraints of the sources.

[44] While electricity markets constitute a flexibility enabler which require a number of organisational and legal elements and may not be considered as a technology, the TRL scale is applied to facilitate the comparison with the other flexibility sources analysed.
For further information on TRLs, see Bruno et al. (2020) Technology readiness revisited: a proposal for extending the scope of impact assessment of European public services. https://dl.acm.org/doi/10.1145/3428502.3428552

Technical characteristics

As indicated above, many categorisations of flexibility sources exist. Likewise, given the variety of flexibility sources it is difficult to provide a single categorisation of their technical characteristics. The main characteristics are hereafter discussed.

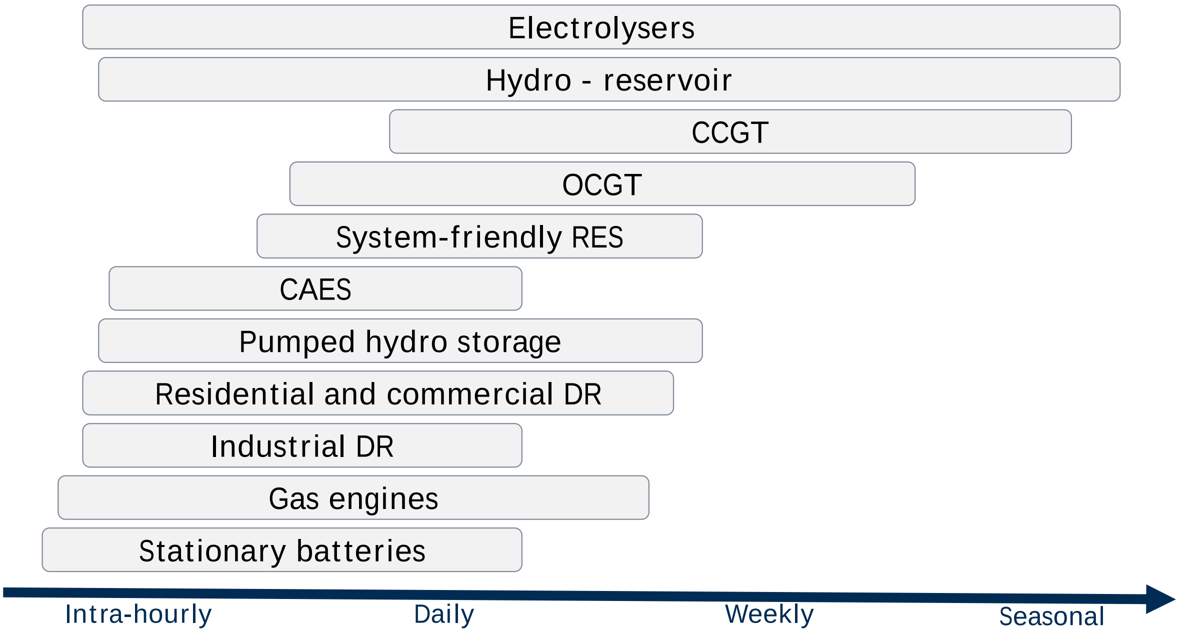
It is important to bear in mind that while typical values are presented here for the flexibility sources, specific assets and sub-technologies may show better technical performance levels than indicated. Significant resources are spent in improving the flexibility of energy technologies, while the flexibility levels achievable e.g. when retrofitting coal or gas fired power plants is constrained by the characteristics of each installation.

The suitability of a specific source for flexibility provision will depend on the combination of its technical characteristics - for example, CCGTs have a high power capacity and are well-suited for providing flexibility in several timeframes, but other resources such as hydropower pumped storage or batteries are, on average, better suite to provide flexibility in intra-hourly timeframes, Other sources of flexibility such as combined heat-and-power-based demand response can be constrained by heat supply limits (minimum in winter, and maximum in summer).

As shown in Figure 5-2, the selected flexibility sources cover, in combination, all flexibility timeframes, from the intra-hourly to the seasonal. However, as several sources are better suited to providing flexibility in certain timeframes, an analysis of flexibility needs for the Energy Community needs to consider the needs in each timeframe (as available flexibility sources may be more restricted in certain of these). Some flexibility sources such as stationary batteries or industrial demand response are more suited to providing flexibility services up to the daily timeframe, but less in the weekly or especially the seasonal timeframe. In contrast, other sources such as CCGTs and storage are well suited to the provision of weekly and seasonal flexibility, while others such as reservoir-based hydropower can provide flexibility in a wider range of timeframes. Nonetheless, one of the main takeaways of the figure is that there may be less flexibility options for the weekly and seasonal timeframes, due to a limitation of available potential (e.g. reservoir hydropower) or lack of technological maturity / profitability (in the case of electrolysers).

Revenue stacking (i.e. the combination of different revenue streams in order to maximise profitability) should be an important strategy to achieve economic viability, and thus the sources shown are likely to provide flexibility in multiple timeframes (as long as they find solutions in order to be able to deliver on various commitments, i.e. not to overcommit to the provision of different flexibility services and being unable to deliver afterwards). Discussions are on-going on the best market design to ensure that the same flexibility capacity is not contracted in different markets. Hence, while specific sources may be technically capable of offering flexibility in a large number of timeframes, in practice the participation of specific operators in flexibility markets may be restricted to a more limited number of timeframes and types of flexibility services.

Figure 5-2 Flexibility timeframe for selected sources



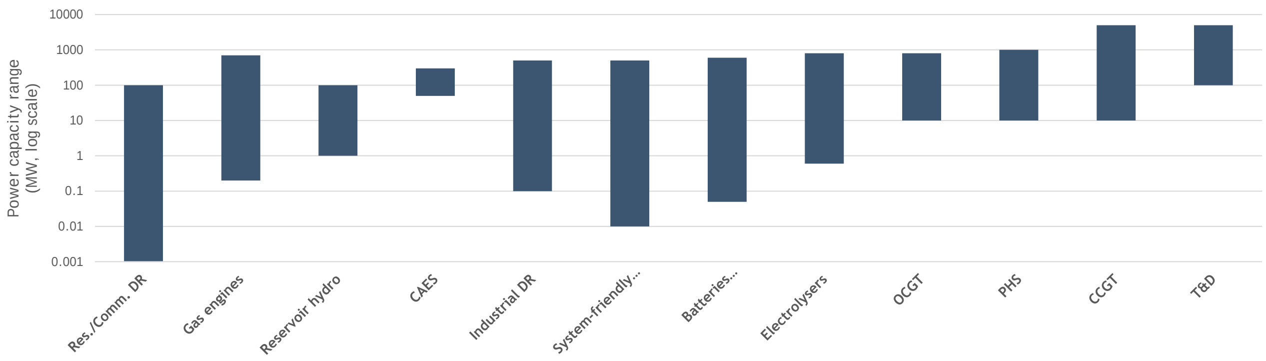
Note: Transmission and distribution as well as electricity markets not shown given their transversal nature

Source: own elaboration

The energy capacity of the sources strongly depends on factors not related to technological aspects, with the notable exception of storage technologies. For example, the energy capacity of OCGTs and CCGTs will be dependent on natural gas availability. The combined energy capacity of demand response in the Contracting Parties' countries will depend on the total industrial/commercial/residential loads and the share of that demand which is controllable. Hence, the demand response energy capacity is strongly dependent on context-specific factors and will vary from country to country, while for other sources (such as electricity markets) the concept of energy capacity does not apply in the first place. The exception are storage technologies, whose energy capacity is largely determined by the technology and is independent from external factors.

The power capacity of the flexibility sources is more linked to the specific technologies concerned (as opposed to energy capacity, which is more context-dependent as discussed) as well as, in the case of aggregated flexibility sources, on the deployment levels. Figure 5-3 presents the range of power capacities of the selected flexibility sources. The flexibility sources assessed cover a wide range of power capacities, from a few kW in the case of stationary batteries and demand response, to several GWs in the case of reservoir hydropower or CCGTs. Moreover, some flexibility sources show a wide power capacity range (such as residential and commercial demand response, or system-friendly renewables) due to the aggregation of the flexibility capacity of hundreds and even thousands of units. Therefore, the potential for provision of flexibility by these sources will depend on the extent of deployment of e.g. smart, controllable loads enabled by the existence of smart meters (in the case of commercial and residential demand response) or renewable power plants (in the case of systems-friendly renewable energy sources).

Figure 5-3 Typical maximum and minimum power capacity of selected flexibility sources



Note: Electricity markets are not shown given they do not have an intrinsic power capacity Source: own elaboration

Regarding conversion efficiency, while significant variation is observed between the flexibility sources, it must be noted that ultimately the costs for providing flexibility are a better indicator of the economic feasibility of a source, rather than the energy (conversion) efficiency of the source. Any source should be allowed to provide flexibility services if it is the most economic way to meet the specific flexibility needs and as long as it satisfies objective, non-discriminatory requirements to ensure delivery of the flexibility service when needed. Theoretically, a source with a low conversion efficiency but low costs for providing flexibility would be competitive. However, in practice conversion efficiency is correlated with operational and thus total flexibility costs for each source, and significant efforts are spent to improve conversion efficiencies.

Most of the selected flexibility sources have a high technological maturity (with a technological readiness level, TRL, close to 9 [45]). The exceptions are electrolysers and compressed air energy storage, which show a TRL of respectively 8 and 6-9. It must be noted that the TRL level may vary for the same flexibility source, as e.g. there are several electrolyser or battery technologies at different stages of maturity. Nonetheless, the TRL here reflects the overall level of technology maturity of the most promising technologies for a flexibility source (e.g. atmospheric alkaline electrolysers, adiabatic CAES). The high technological maturity of the selected sources is a reflection that the selection focused on sources which already provide or have a significant potential to provide flexibility in the Energy Community or other regions. There are, nonetheless, several flexibility sources in lower levels of technological readiness, which were however not selected.

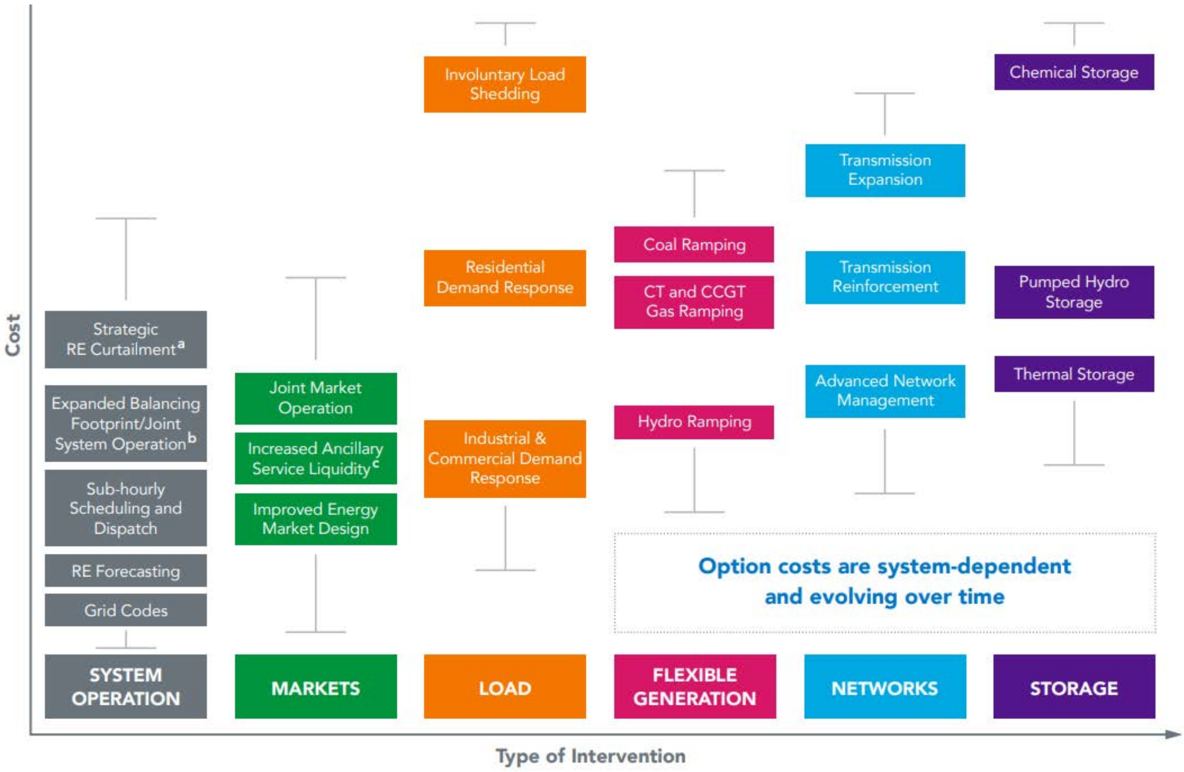
Despite the high technical maturity of the surveyed sources, this does not mean that further technological improvements are not needed. Additional innovations regarding e.g. operational flexibility and conversion efficiency would be relevant to improve the business case of electrolysers. Moreover, reducing costs remains a critical for achieving profitability for certain flexibility sources. While not within the scope of this study, technological innovation should remain an important factor for ensuring the increasing flexibility needs of the Energy Community are cost-efficiently met.

[45] The technology readiness level is a scale developed by NASA and used since 2014 for categorising the maturity of technologies in the European Union Framework Programmes (Horizon 2020 and Horizon Europe). The TRL scale goes from 1 (basic principles observed) to 9 ('actual system proven in operational environment'). See https://ec.europa.eu/research/participants/data/ref/h2020/wp/2014_2015/annexes/h2020-wp1415-annex-g-trl_en.pdf

Economic characteristics

Flexibility sources have different costs, which are often system-dependent. The figure below provides an illustrative example of the relative costs of different energy system integration options. This shows that in general, options focused on changes to system operation and market design (for example joint cross-border procurement of balancing services) tend to be cheaper than new sources of flexibility.[46] Still, changes to system operation and market design have implementation costs and often require institutional changes. Nevertheless, certain reform measures that ensure better utilisation of existing capacities and assets are legal requirements and shall be undertaken.

Figure 5-4 Relative economics of the deployment of flexibility options



Source: 21st Century power (2014)[47]

The table below provides an overview of indicative fixed and variable costs for the selected flexibility sources.

Table 5-2 Flexibility sources costs[48]

Flexibility source	Fixed costs	Variable costs
Open-cycle gas turbine (OCGT)	524-550 EUR/kW (CAPEX)	O&M: 3% of CAPEX excluding fuel costs Starting cost: 21-30 EUR/MW 1-61 EUR/MW post-flexibilization[49]
Combined-cycle gas turbine (CCGT)	806-850 EUR/kW (CAPEX)	O&M: 2.5% of CAPEX excluding fuel costs Starting cost: 33-41 EUR/MW

[46] 21st Century Power Partnership (2014), Flexibility in 21st Century Power Systems
[47] 21st Century Power Partnership (2014), Flexibility in 21st Century Power Systems
[48] Values converted from US dollars to Euros using an average 2020 exchange rate of 1 EUR = 1.1422, following Eurostat ERT_BIL_EUR_A
[49] After measures to increase plant flexibilization

Flexibility source	Fixed costs	Variable costs
		48 EUR/MW - post-flexibilization
Gas engines	500-530 EUR/kW (CAPEX)	4.1 EUR/MWh
System-friendly variable RES	Increased LCOE in some cases[50]	-
Stationary batteries (Li-Ion)	150-1300 EUR/kW (CAPEX)	Energy installation cost 240-735 EUR/kWh
Compressed air energy storage (CAES)	400-1200 EUR/kW (CAPEX)	0.22 EUR/MWh
Hydro - reservoir	CAPEX: • >10MWe: 920-6 700 EUR/kWe • 1-10 MWe: 875-3 500 EUR/ kWe • ≤1 MWe: 2 975-8 755 EUR/kWe	O&M: 1%-4% of annual investment costs (2%-2.5% for large hydro)
Pumped storage hydro (PHS)	1500-3500 EUR/kW (CAPEX)[51]	Fixed O&M: 1.4 - 2% of capital cost Variable O&M: 0.45 EUR/MWh
Electrolysers	CAPEX: 560-875 EUR/kW (2020) 115-270 EUR/kW (2050)	System cost 175-610 EUR/kW (exc. fixed costs)
Demand response	Not significant	Not significant
Transmission and distribution grids	750 kV OHL[52]: 360 - 380 kEUR/km 400 kV OHL: 240 - 280 kEUR/km 400 kV OHL: 370 - 420 kEUR/km 220 kV OHL: 160 - 200 kEUR/km 220 kV OHL: 230 - 250 kEUR/km Transformers: 400/220 kV - 6.750 kEUR/MVA 400/220 kV - 8 kEUR/MVA 220/110 kV - 12 kEUR/MVA	Unit transmission costs in 2019: - Albania - 6.08 EUR/MWh - Bosnia and Herzegovina - 7.05 EUR/MWh - Montenegro - 7.98 EUR/MWh - North Macedonia - 3.79 EUR/MWh - Serbia - 4.06-4.09 EUR/MWh The cost of losses is above 1 EUR/MWh for Albania Bosnia and Herzegovina, Montenegro, Serbia and below 1 EUR/MWh for North Macedonia
Electricity markets	Highly complex[53] For the integration of balancing markets: - imbalance netting estimated to cost 19.1-20.7 M€ (one-off) and 0.66-1.3 M€/year (recurrent) - Allowing exchange of balancing products on top estimated to cost	NA

[50] Designing generator units in order to provide a smoother generation profile leads to a lower total energy output compared to a design aiming to maximise annual energy output, and thus to an increase in the levelized cost of electricity. Additional CAPEX can also be incurred, but is difficult to quantify due to the limited examples of system-friendly parks.
[51] This is the credible range of values identified in the literature. However, there is significant divergence of values across the literature, and actual CAPEX costs will is strongly site-dependent.
[52] Overhead line
[53] Costs may include for example: Legislative and regulatory processes for developing and implementing market rules, development of the necessary IT systems, administrative procedures by market operators, etc.

Flexibility source	Fixed costs	Variable costs
	76.1-96.4 M€ (one-off) and 1.8-4.6 M€/year (recurrent) - Increasing interconnection capacity available for balancing market trade estimated to cost 125.5-274.2 M€ (one-off) and 27.2-39.9 M€/year (recurrent)	

5.2 Best practices for the development and utilisation of flexibility sources

Best practices to facilitate the deployment of each of the selected flexibility sources based on the literature review are presented in the database. Based on our analysis of the identified best practices, they comprise the following main types:

- Operational flexibility best practices: Best practices for maximisation of the flexibility of new or existing assets, covering both equipment and software design as well as new operational practices;
- Communication and control solutions best practices, allowing for the procurement and activation of (aggregated) flexibility services from distributed flexibility sources;
- Electricity market design best practices, aiming at providing both explicit and implicit incentives to flexibility in a non-discriminatory (technology-neutral) manner, sourcing the most cost-efficient flexibility sources to meet the needs, and at allocating all relevant system costs in a transparent way to the concerned market participants. Best practices here would include the phase-out of price regulation and the advancement of market coupling;
- Other policy best practices affecting revenues and costs of flexibility source operators (or levelling the playing field), including the design of renewable energy sources' support schemes, introduction of carbon pricing, revision of energy taxation and network tariff structures, and the removal of subsidies to fossil fuel based power generators;
- The streamlining of environmental permitting and electricity market qualification procedures, as well the adaptation of these procedures to new technologies and market participants (e.g. new entrants, aggregators);
- Other policies and actions not related to the above, such as the revision of gas supply contract provisions, including removal of take-or-pay obligations.

Generally, the analysis indicates that best practices aiming at increasing the operational flexibility of assets are best decided on and implemented by the concerned asset operators. Flexibility best practices to be implemented by market operators can be highly diverse and specific to each source - examples of such best practices are presented in Table 5-3.

It must be noted that while regulated infrastructure operators are (as operators of flexibility assets such as transmission and distribution grids) best placed to develop solutions maximising the operational flexibility of their assets, while policy makers and regulators can and should ensure that the decisions of infrastructure operators maximise societal benefits.

Table 5-3 Selected examples of flexibility-source specific best practices identified

Flexibility source	Best practices specific to the flexibility source
Open-cycle gas turbine (OCGT)	Siemens Energy is testing an advanced OCGT during 2020-2024 in the US for flexible operation to accommodate solar generation variability, expecting to quadruple the ramp-up rate compared to other technologies.[54]
Combined-cycle gas turbine (CCGT)	Measures to increase flexibility focus on the design and operation of the heat recovery steam generator (HRSG) and include reducing wall thickness, installing a bypass for the waste heat (allowing a CCGT to operate as an OCGT).[55] Take-or-pay obligations of gas supply contracts or capacity-based power purchase agreements may restrict gas-fired power plants' flexibility, so contractual provisions need to be revised where present in order to allow gas power plants to operate flexibly.
Gas engines	Linkenheil et al. for EUGINE (2017)[56] indicate that the consideration of the different costs and constraints for the provision of flexibility need to be considered, including "contribution to must-run, low possibility of start-stop cycles, high efficiency drops at minimum load operation, high fixed cost and environmental aspects arising from life cycle assessment". IRENA (2019)[57] notes that gas engines have been installed in highly granular electricity markets such as ERCOT in the US, which better allow to value the flexibility contributions of the technology. The IEA (2018)[58] indicates gas engines can also be used for combined heat and power generation, for example for the provision of power and heat for the Kiel (Germany) district heating network, with the ability to provide also only power when needed.
System-friendly variable RES	USAID[59] lists procurement approaches to incentivise system-friendly renewables: - Time-based incentives, including for example California's Renewable Auction Mechanism in 2011-2015, or Chile's competitive procurement round in 2017 which included supply blocks. - Location-based incentives, such as re-development zones (with simpler environmental / grid permitting process, such as in South Africa and Philippines), capacity limits per area (in Kazakhstan, Germany), and site-specific auctions (in Bangladesh, or in many cases for offshore wind auctions). - Virtual or physical hybrids, that is, the aggregation of different renewable energy technologies and potentially flexibility sources either physically (at the same site) or virtually (in different locations), such as the hybrid solar-wind procurement scheme in India (physical hybrid) and the Next Kraftwerke virtual power plant in Germany. May et al. (2015) indicate two approaches in the design of support schemes in Germany could incentivise system-friendly wind power: changing the 'benchmark location' or using the 'production value-based benchmark approach' for renewable energy auctions.

[54] https://www.siemens-energy.com/global/en/news/magazine/2020/hl-clcassic-duke-energy.html
[55] IRENA (2019) Flexibility in Conventional Power Plants - Innovation Landscape Brief
[56] Linkenheil et al. for EUGINE (2017) Flexibility Needs and Options for Europe's Future Electricity System
[57] IRENA (2019) Flexibility in Conventional Power Plants Innovation Landscape Brief
[58] IEA (2018) Status of Power System Transformation 2018 - Advanced Power Plant Flexibility
[59] Tetra Tech for USAID (2020) Designing Solutions in System Friendly Renewable Energy Competitive Procurement - Scaling Up Renewable Energy Project

<table>
<tr><th>Flexibility source</th><th>Best practices specific to the flexibility source</th></tr>
<tr><td>Stationary batteries / Compressed air energy storage / Electrolysers</td><td>Inherently flexible. Best practices include providing the right market incentives for deployment (discussed in detail in Tasks 4-5, report upcoming) and having the right control systems allowing smart operation to maximise revenues (see e.g. IEEE, 2017[60]).</td></tr>
<tr><td>Hydro - reservoir</td><td rowspan="2">The HydroFlex indicates specific solutions include novel techniques for generator design in order to facilitate flexible operation, and the use of back-to-back converters in the interface of the hydropower units and the AC grid. The IEA (2019)[61] indicates that "modern technology, digitisation, improved maintenance methods and innovations in the technical components and system design" are some of the techniques to increase flexibility of hydropower. It furthermore notes that existing hydropower can be refurbished to increase its flexibility (without building new dams) either by redesign the plant to introduce pumping capabilities (in the case of reservoir or run-of-river hydropower), or repowering.</td></tr>
<tr><td>Pumped storage hydro (PHS)</td></tr>
<tr><td>Demand response (industrial, commercial and/or residential)</td><td>- Standardisation or at least interoperability of hardware (EMS, smart meters, charging stations etc.) and market rules and energy products
- The assets delivering flexibility products should be connected to a smart (sub)meter/gateway to collect data. Telemetry requirements should be established according to capacity thresholds. Other equivalent solutions (where possible) should be implemented for smaller units or aggregators[62]</td></tr>
<tr><td>Transmission and distribution grids, including interconnectors</td><td>Flexible AC transmission system (FACTS) allow to optimise the operation of electricity transmission (and distribution) networks, being able to increase the transfer capacities, improve stability or provide for example fast reactive power capabilities.
Lumbreras and Ramos (2019) also indicate solutions such as combination of AC and DC transmission, the use of advanced conductors with a high transfer capacity and high-temperature capability, and new configurations (e.g. 6 or 12 phases). The authors highlight especially the importance of underground cables and HVDC transmission in the future, and the increasing relevance of upgrading of control centres and substations.
MEPSO's (2020) TYNDP 2020-2029 indicates a number of planned actions to increase the flexibility of North Macedonia's electricity networks, including the use of new conductors with low sag, FACTS and phase shifting transformers.
Cruz et al. (2018) discuss meshing (as opposed to a radial topology) as a means of improving the flexibility of distribution networks.</td></tr>
</table>

Policy makers and regulators should design technology-neutral policies and measures to incentivise flexibility provision by the operators of flexible assets and to minimise system flexibility needs. Best practices by policy makers and regulators will be analysed in detail in Tasks 4-5, but common barriers for the deployment and utilisation of flexibility sources can already be identified, and include:

[60] Dall'Anese et al. (2017), Unlocking Flexibility: Integrated Optimization and Control of Multienergy Systems

[61] IEA (2019) Flexible hydropower providing value to renewable energy integration. https://www.ieahydro.org/media/51145259/IEAHydroTCP_AnnexIX_White%20Paper_Oct2019.pdf

[62] European Smart Grids Task Force (2019) Demand Side Flexibility Perceived barriers and proposed recommendations

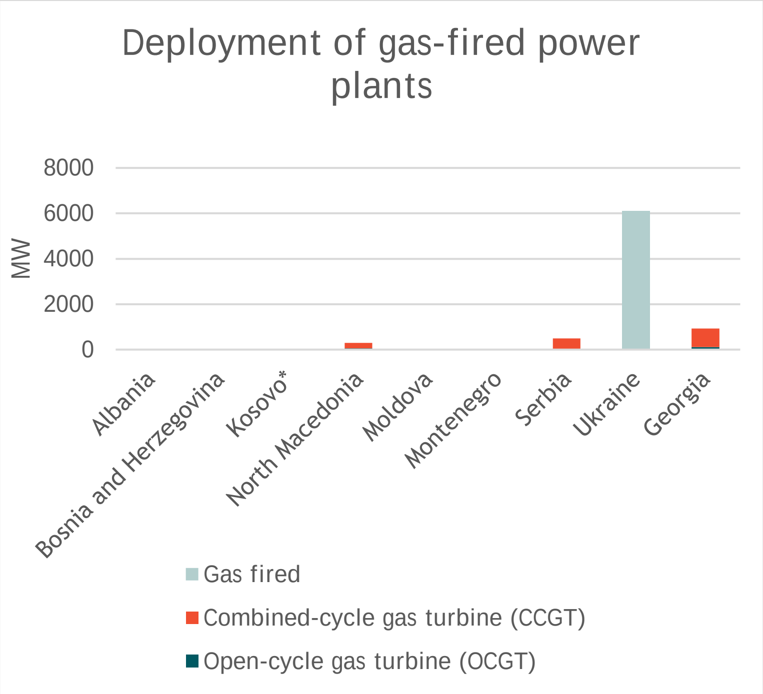
- ✓ Lack of clear guidance on energy & climate polices and targets as well as strategies for the development of flexibility
- ✓ Regulatory frameworks failing to comprehensively address flexibility or certain flexibility source categories (e.g. storage)
- ✓ Safety and environmental rules which are not adapted to the permitting of new flexible technologies
- ✓ Electricity markets[63] are inexistent, incipient or with significant entry barriers for flexibility sources, such as due to inadequate pre-qualification requirements for energy markets, untargeted[64] retail price regulation or wholesale/retail market concentration
- ✓ Limited physical transmission interconnection capacities, limited offering by system operators of those capacities to the market and/or inefficient use of the capacities due to lack of market coupling
- ✓ Network planning regulation which does not require TSOs and DSOs to consider non-conventional flexibility solutions nor avoids CAPEX bias
- ✓ Network regulation and tariff structures which do not appropriately allocate network and system costs as far as possible to those causing those costs and do not value flexibility sources for avoided system costs
- ✓ Energy taxes and levies which provide inadequate signals to energy consumption and unduly burden flexibility sources (e.g. due to double taxation applicable to energy storage)
- ✓ Low levels of deployment of residential smart meters and other required measures for smart grids

5.3 Deployment status in the Energy Community

The selected flexibility sources are deployed at different levels in the Energy Community Contracting Parties. Deployment of gas-fired power plants in the Energy Community consists first of 10 785 MW in Ukraine of gas-fired installed power generation capacity. The CCGT capacity in Moldova, Ukraine and Georgia add up to 1 405 MW. Kosovo* has been considering a CCGT plant but suffers due to lack of gas infrastructure. Additionally, there is 1 994 MW of OCGTs in Georgia, North Macedonia, Moldovia and Serbia. Values for gas engines deployment could not be identified. Due to the uncertainty regarding the level deployment of gas-fired power plants in the Contracting Parties, the values presented are based on the Carbon Pricing study, but will be updated for the subsequent project tasks.

[63] Wholesale and retail energy markets, capacity mechanisms (when necessary) and/or ancillary services markets
[64] That is, regulation of prices to a broad range of consumers and not only to vulnerable consumers

Figure 5-5 Deployment of supply side flexibility sources



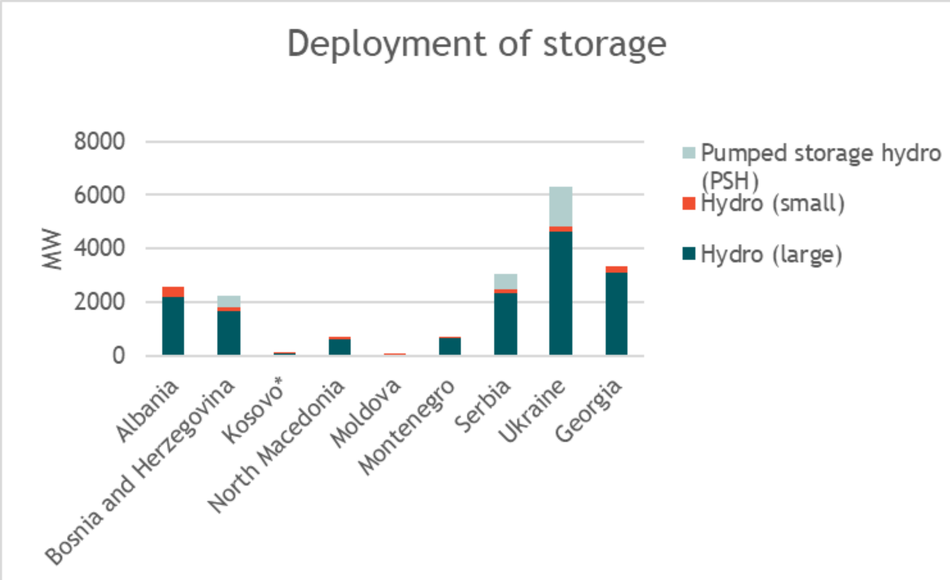
Source: *Kantor &E3M, A Carbon pricing design for the Energy Community (2021)*

Note: data refers to latest year available.

Deployment of storage flexibility sources in the Energy Community is more widely spread, with all Contracting Parties having large and small hydro power in place, adding up to 16,5 GW.[65] Only three countries (Bosnia and Herzegovina, Serbia and Ukraine) have pumped storage hydro available. Currently, North Macedonia is tendering for a new pumped storage facility. The values presented are based on the Energy Community Secretariat Implementation Report 2020, but will be updated for the subsequent project tasks.

[65] Note that we expect small hydro to be predominantly run-of-river or storage run-of-river hydropower projects, and as such only a share of the available capacity (that which refers to storage run-of-river projects) would act as storage.

Figure 5-6 Deployment of storage flexibility sources. Status as of 2019.

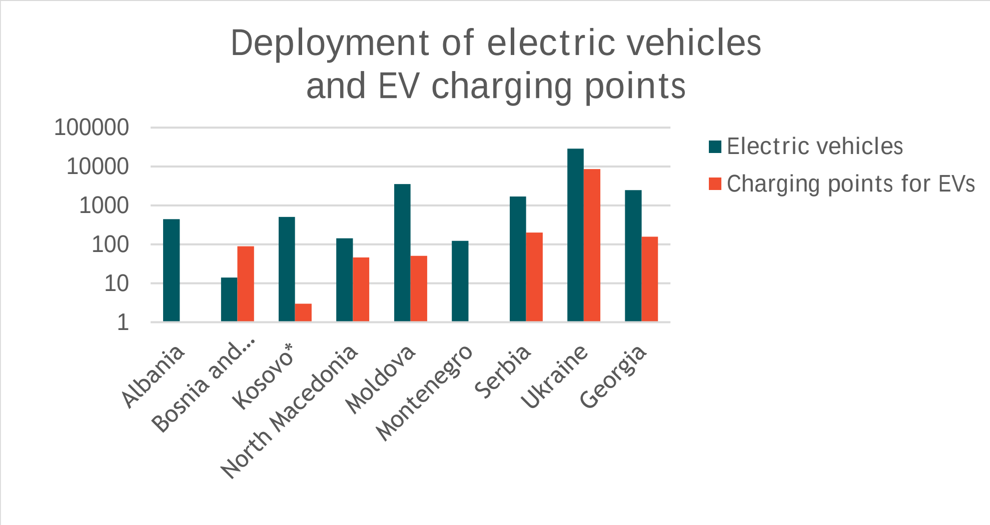


Source: ECS (2020), Annual Implementation Report 2020[66]

There is limited information regarding the use of demand response flexibility sources in the Energy Community. Projects dealing with automated demand response software/hardware have been identified in Kosovo*, Montenegro, North Macedonia, Serbia and Ukraine.[67] Some experience seems to be available regarding industrial demand response in Montenegro (50 MW provided by the aluminium industry) and in Bosnia and Herzegovina (via the use of the manual frequency restoration reserves - mFRR). Additionally, IndustRE has quantified the benefits of flexible industrial demand response for the EU, Albania and Bosnia and Herzegovina for different RES penetration scenarios.[68] Regarding residential and commercial demand response, there is information with regards to EV and EV charging point deployment (see below); however, there is no indication of smart charging[69] that would allow EV batteries to be used as a flexibility source. Pilot projects for EVs in the context of smart grids have been identified in Montenegro, North Macedonia and Ukraine.[70] No information was available with regards to power to heat.

[66] Energy Community (2020), Annual Implementation Report 2020
[67] Energy Community (2020), Smart Grid Opportunities in the Energy Community - Scoping Study.
[68] IndustRE (2017), Quantifying the Economic Benefits of Flexible Industrial Demand.
[69] Smart charging is defined as a way of optimising the charging process according to distribution and/or transmission grid constraints, local availability of renewable energy sources and customers' preferences. When charged smartly, EVs can provide demand-side flexibility by charging when prices are low, therefore following VRE availability and avoiding charging during scarcity events when prices are very high, causing, among other things, less stress in the distribution and transmission grid. IRENA (2019), Demand-Side Flexibility for Power Sector Transformation - Analytical Brief.
[70] Energy Community (2020), Smart Grid Opportunities in the Energy Community - Scoping Study.

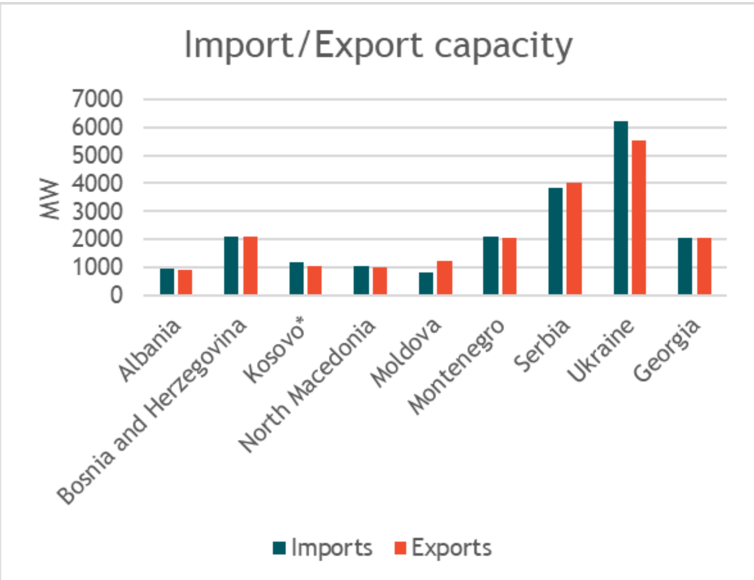
Figure 5-7 Deployment of EVs and charging points in the Energy Community. Status as of 2019.[71]



Source: ECRB (2021), E-mobility in the Energy Community Contracting Parties; ANRE (MD).

Regarding transmission and distribution networks, the diagram below shows the import/export capacity in the Energy Community. According to the ECRB (2020), the net transfer capacities did not change significantly in the 2015-2018 period, with eventual changes being due to adjustments in the NTC calculation methodology (with increases being observed for Bosnia and Herzegovina and Montenegro).[72]

Figure 5-8 Import and export capacity in the Energy Community



Source: ECS (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties; ENTSO-E Transparency Platform.

Finally, the reform of the electricity markets is ongoing across the Energy Community. In terms of enabling flexibility, most work is needed in view of the further regional integration of the wholesale markets. There is work ongoing for 'reciprocal application of the Regulation on establishing a guideline

[71] Note: No data available for Albania (on number of EVs and charging points) and Montenegro (on charging points)
[72] ECRB (2020), Wholesale Electricity Market Monitoring - Report for the Energy Community Contracting Parties

on capacity allocation and congestion management (CACM)'.[73] Further, some Treaty reforms envisaging reciprocity with Member States and credible enforcement of Energy Community rules, which are relevant to facilitate market coupling projects in the CESEC region are still pending.[74] Additional details per Energy Community Contracting Partner are provided in the annex.

Table 5-4 Status of electricity markets in the Energy Community

Electricity markets	Unbundling	Access to the system	Wholesale market	Regional integration
Albania	88%	78%	65%	48%
Bosnia and Herzegovina	20%	93%	70%	42%
Georgia	72%	63%	63%	NA
Kosovo*	100%	81%	75%	45%
Moldova	55%	48%	38%	15%
Montenegro	100%	85%	70%	39%
North Macedonia	100%	90%	63%	57%
Serbia	68%	90%	85%	51%
Ukraine	60%	58%	60%	20%

Note: Access to the system refers to network access tariffs, third party access and transposing/implementing the Transparency Regulation and Connection Network Codes. Wholesale market refers to the market's status, transposing/implementing REMIT and establishment of day-ahead, balancing and ancillary services markets.
Source: Adapted from Energy Community Secretariat (2021), Annual Implementation Report 2021[75]

The following sources are not yet deployed in the Energy Community:

- System-friendly variable RES;
- Stationary batteries;
- Compressed air energy storage (CAES);
- Electrolysers.

Regarding electrolysers, the Energy Community acknowledges the importance of the role of hydrogen in the energy transition, and has carried out an economic analysis to provide guidance on which hydrogen technologies might have the greatest economic potential for the Contracting Parties.[76] However, no indication is given with regards to electrolyser deployment yet.

[73] Energy Community Secretariat (2020), Annual Implementation Report 2020
[74] Central and South-Eastern European Connectivity (CESEC) High Level Group (2021), Meeting Conclusions - 21 September 2021
[75] https://www.energy-community.org/dam/jcr:0af3b17a-3759-4a23-a2ef-3134784e217c/EnC_IR2020.pdf
[76] Energy Community (2021), Study on the potential for implementation of hydrogen technologies and its utilisation in the Energy Community

6 Annexes

6.1 Detailed status of Contracting Parties with regards to electricity markets[77]

CP	Status
Albania	• Delayed implementation of a power exchange and day-ahead market affects competition • Balancing market operational since April 2021 • Implemented common dimensioning of the balancing reserve within the Albania - Kosovo* (AK) control block, as well as joint provision of secondary control • Cross-border capacities allocated through SEE CAO, except split auctions with EMS of Serbia
Bosnia and Herzegovina	• Cross-border transmission capacity is allocated through SEE CAO (with Croatia and Montenegro), or bilateral auctions (with Serbia). • Balancing cooperation exists within the LFC block with Croatia and Slovenia, and bilaterally with Montenegro and Serbia • The adoption of a new legal act which would enable the establishment of a day-ahead market was postponed • Market coupling depends on the establishment of a day-ahead market • The new law of Republika Srpska provides for the gradual deregulation of generation prices.
Georgia	• The launch of day-ahead, balancing and ancillary services markets was postponed to 2022. GENEX and GSE are running joint testing in preparation for their launch • Georgia is not interconnected with other Contracting Parties nor EU MSs, thus, no regional integration taking place. A derogation from cross-border cooperation is granted. • No coordinated capacity allocation of cross-border capacities with neighbouring countries, except bilateral with Turkey
Kosovo*	• Forward and daily cross-border capacities are allocated through SEE CAO, except with Serbia, where capacities are not offered to the market at all. • The bulk supply agreement between the state producer and supplier distorts competition • The establishment of a day-ahead market hinges on the establishment of the Albanian day-ahead market, which continues to be delayed • A competitive balancing market exists • Following ECRB recommendation, ERO adopted rules setting the procedure for designating the Nominated Electricity Market Operator
North Macedonia	• The wholesale market is open and the balancing market is operational, but the establishment of the day-ahead market is delayed. • Interconnection capacities on the border with Greece and Kosovo* are allocated through SEE CAO, others bilaterally. • The market coupling project with Bulgaria hinges on the creation of a day-ahead market in North Macedonia
Moldova	• The entry into force of the wholesale electricity market rules, initially envisaged for 2 October 2021, is postponed until 2022. • The Moldovan and Ukrainian transmission system operators have made progress towards joint allocation of cross-border capacities and settlement of unintentional deviations • The delays in adoption of the wholesale electricity market rules in Moldova impede further progress in regional integration. • Interconnection with Romania expected end of 2024
Montenegro	• The wholesale market is open for competition. • The balancing market is competitive and functional, save for the balancing reserve. • The day-ahead market is not functional yet. • Capacities are allocated through SEE CAO for all interconnections except with Serbia where bilateral auctions apply. • The transmission system operator exchanges balancing energy on a bilateral basis with Bosnia and Herzegovina and Serbia • Market coupling is conditioned on the establishment of a day*ahead market
Serbia	• Bilateral, day-ahead and balancing markets are operating, but no intraday market.

[77] This annex quotes the Energy Community Secretariat Implementation Reports of 2020 and 2021

CP	Status
	• Prices of balancing reserves continue to be regulated. • Interconnection capacities on the border with Bulgaria and Croatia are allocated through JAO, others bilaterally. • The new Energy Law sets a legal framework for the designation of a nominated electricity market operator and market coupling as well as for participation in European balancing platforms
Ukraine	• Bilateral, day-ahead, intraday, balancing and ancillary services markets are operational, but subject to many regulatory interventions. Non-compliant public service obligations and regulated prices of state-owned generation companies are impeding competition. Losses are procured by the transmission system operator on the market, but distribution system operators are obliged to buy a significant amount of their losses from state-owned Energoatom. • Cross-border capacity is allocated via unilateral auctions, i.e not coordinated with neighbouring transmission system operators. • Arrangements for the settlement of unintended deviations were agreed between the transmission system operators of Ukraine and Moldova, but their implementation is delayed. • The Electricity Market Law was amended to allow for joint auctions, which are currently being prepared on Burstyn Island and with Moldova

6.2 Characterisation of flexibility sources

See Excel file

Study on flexibility options to support decarbonization in the Energy Community

Task 2&3

Trinomics

Artelys
OPTIMIZATION SOLUTIONS

Table of Contents

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List of Abbreviations

AL	Albania
BA	Bosnia and Herzegovina
BiH	Bosnia and Herzegovina
BG	Bulgaria
CAES	Compressed air energy storage
CESA	Continental European Synchronous Area
CCGT	Combined cycle gas turbine
CP	Contracting Party
EnC	Energy Community
ECS	Energy Community Secretariat
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	Emissions Trading System
EU	European Union
EU+	EU plus Norway, Switzerland, UK
EV	Electric Vehicle
FM	Fragmented Market
GE	Georgia
GHG	Greenhouse Gas
GR	Greece
GW	Gigawatt
HR	Croatia
HU	Hungary
IPS	Integrated Power System
KS	Kosovo*
MD	Moldova
ME	Montenegro
MI	Market Integrated
MK	North Macedonia
MW	Megawatt
NG	Natural Gas
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
PHS	Pumped storage hydro
PL	Poland
PV	Photovoltaic system
RES	Renewable energy sources
RO	Romania
RS	Serbia
SK	Slovakia
TYNDP	Ten-year network development plan
UA	Ukraine
UPS	Unified Power System of Russia
VRE	Variable renewable energy
WB6	Western Balkans, including Albania, Bosnia and Herzegovina, Kosovo*, Montenegro, North Macedonia and Serbia
XK	Kosovo*

Executive Summary

Flexibility solutions allow the power system to reliably and cost-effectively manage the variability and uncertainty of supply and demand across all relevant timescales[1]. This report assesses flexibility solutions needed to support high vRES deployment in the Energy Community, from the daily to the seasonal timescales[2].

This report determines the need for and role of flexibility options to support decarbonization in the Energy Community (EnC) towards 2040.[3] First, it focuses on the current utilization of existing flexibility solutions. Second, future flexibility needs are analysed and cost-optimal portfolios of flexibility solutions are determined considering a wide range of scenarios in terms of variable renewable energy sources (vRES) deployment, coal phase-out and levels of interconnection capacity.

Existing flexibility sources dominated by coal and interconnections

Across all Contracting Parties (CPs) of the EnC, coal-fired power generation and cross-border interconnection capacities represent around 30 GW and 20 GW[4], respectively, of existing infrastructure in 2020, and as such they are the main existing flexibility sources. Hydropower, present in almost all CPs, and gas-fired generation, mostly present in Ukraine, represent secondary contributors with around 12 GW and 8 GW of installed capacities.

When it comes to the question, which flexibility solutions currently existing will remain by 2030 and 2040, it appears that all interconnection capacities are expected to persist. Figure 1 indicates the transmission infrastructure capacities between Contracting Parties. The NTCs in Ukraine and Serbia are the most significant ones (6 GW and 4 GW respectively).

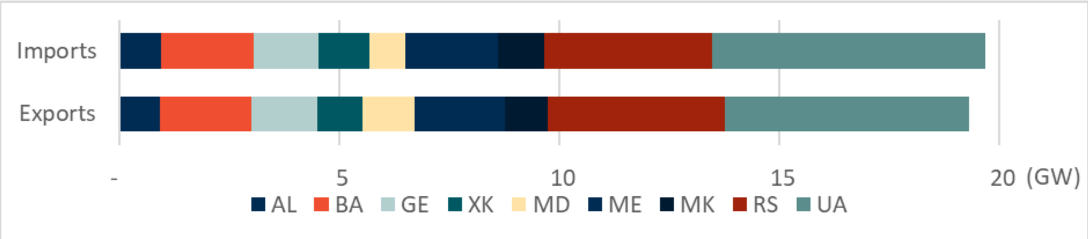

Figure 1 - 20 GW NTC split among Energy Community

Significant reductions of coal/lignite and gas-fired generation capacity can be expected in the Energy Community by the year 2030 and 2040 as existing assets reach their end of life, or due to national coal/lignite phase-out strategies from certain CPs, as depicted in Figure 2. By 2040, 74% of 2020's coal/lignite capacities and 79% of gas-fired capacities will be decommissioned or reach the end of their lifetime.

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[1] Please refer to the *Task 1 Report: Analysis of technical and non-technical sources of flexibility*, for a review of possible flexibility sources.

[2] Flexibility required at the sub-hourly timescale (reserves, inertia), adequacy issues (considering extreme events and various weather years), or coming from internal grid constraints (congestions) were not included in the scope of this study.

[3] It is important to note that the present analysis does not take into account the consequences related to the invasion of Russia in Ukraine since 24 February 2022. Nonetheless, the assessments carried out for the years 2030 and 2040 consider a full synchronisation of Ukraine and Moldova with the Continental European Synchronous Area (CESA).

[4] Sum of the Net Transfer Capacity (NTC) of interconnections over all borders of the 9 CPs.

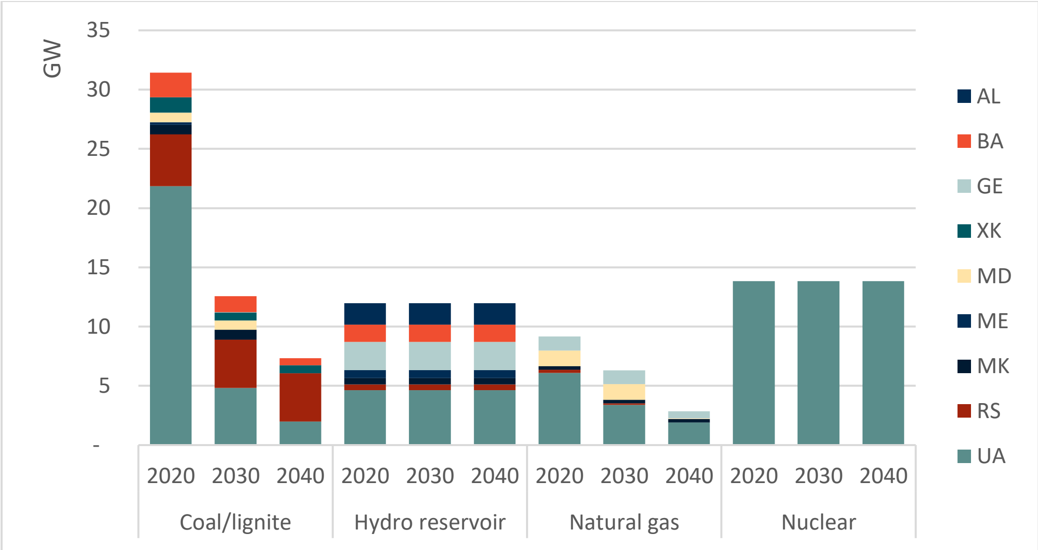

Figure 2 - Evolution of existing flexibility solutions in the CPs[5]

Renewables will play in increasing role by 2030, 2040 - to a varying extent

Three generation capacity scenarios are considered in this study, for 2030 and 2040:

- ✓ a Baseline scenario[6], reflecting a *business-as-usual* development, with relatively slow uptake of renewable energy sources (RES).
- ✓ a Moderate scenario, which reflects an intermediate scenario between Baseline and Ambitious.
- ✓ an Ambitious scenario[7], with strong decarbonization of the power generation sector, due to a high uptake of RES and almost complete phase-out of lignite and coal-based power generation.

Figure 3 presents the capacity expansion of wind and solar for both the 2030 and 2040 horizons and the three scenarios. The differences are quite significant between Baseline and Ambitious configurations, with a vRES uptake (combining wind and solar) of +50% in 2030 and +85% in 2040.

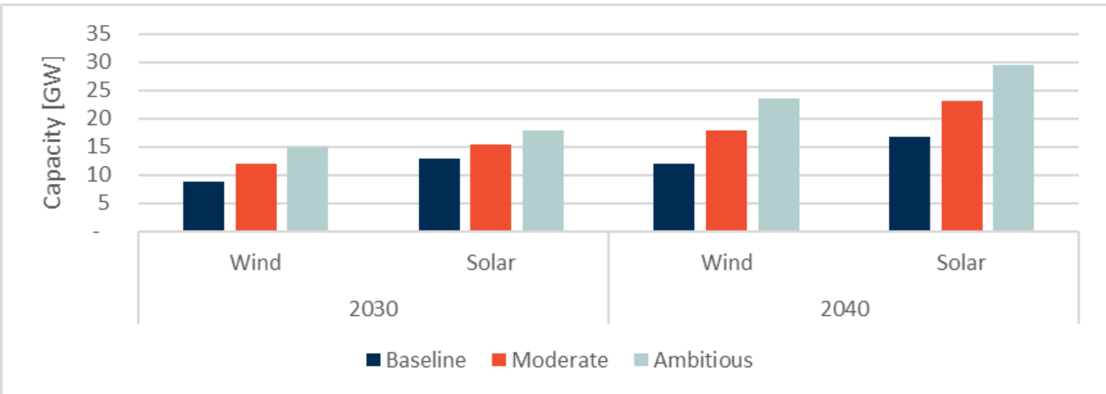

Figure 3 - vRES uptake in the Energy Community in the different scenarios, for both 2030 and 2040

[5] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[6] Based on the Baseline scenario of the EnC-Carbon Pricing study
[7] Based on Gradual Carbon Pricing strategy and Market integration scenario (GradualCP-MInt) from the EnC-Carbon Pricing study

Flexibility needs will increase by 2030 and 2040

The evolution of the CPs' energy systems (especially the high penetration of RES, but also the change in the demand level) induce changes in flexibility needs. Flexibility needs are a metric that captures the dynamics of the residual load (calculated as the hourly demand less the variable RES generation), on daily, weekly and seasonal timescales. Aggregated flexibility needs over all CPs increase from 2030 to 2040 due to the increase of RES. They also increase across scenarios (from Baseline to Ambitious) as depicted Figure 4. It should be noted that intra-hourly flexibility needs are not considered in this study.

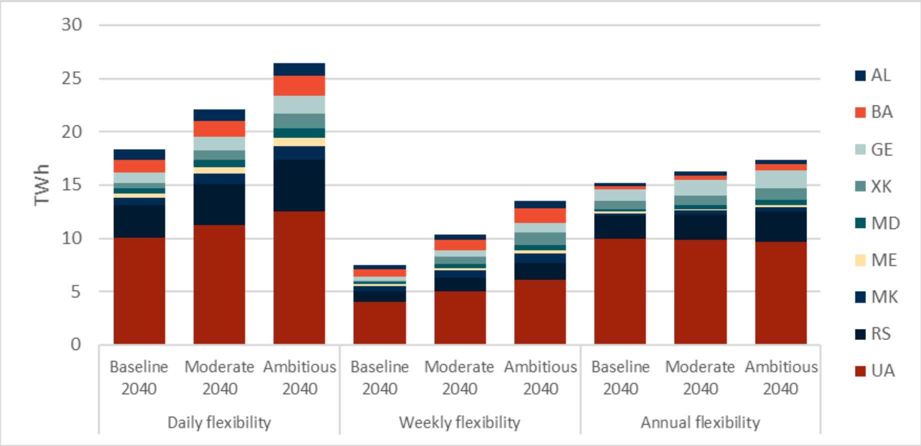

Figure 4 - Aggregated flexibility needs in the Energy Community among scenario in 2040

Modelling a cost-optimal flexibility portfolio

In order to determine the cost-optimal flexibility portfolios for each CP in 2030, 2040, the Artelys Crystal Super Grid was used. The modelling exercise was performed via a joint optimisation of the flexibility portfolio and its operations for the different scenario, with an hourly time resolution and a country based geographical mesh. Eight CPs were modelled jointly with the EU Member States (MSs), whereas Georgia was modelled independently as an electric island with partial interconnection with neighbouring countries. The main assumptions and outputs of the model are summarized in Figure 5. Two levels of cross-border exchange capacities are considered in this study, reflecting two market integration scenarios. One approach restricts the utilisation of NTC capacities to the values observed in the past, whereas the other one makes available at least 70% of the nominal transmission capacities for trading purposes.

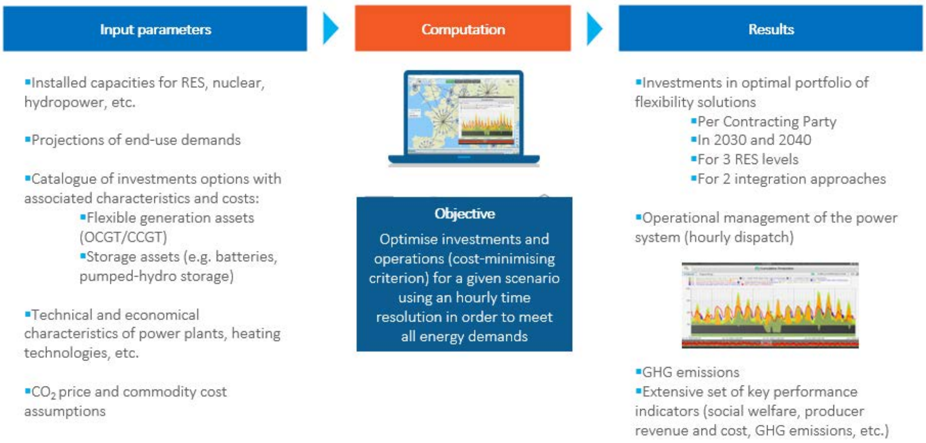

Figure 5 - Overview of main input and output parameters of Artelys Crystal Super Grid

Optimal flexibility solutions in the Contracting Parties

Three main conclusions can be drawn from the model-based analysis of the different scenarios:

- ✓ There is no need for investments in additional flexibility capacities by 2030. The existing capacities that provide system flexibilities, namely cross-border interconnections (enabling increasing imports), gas-fuelled power plants and storage assets (including reservoir hydro), but also other thermal plants can cope with the rising flexibility needs related to an increasing degree of RES deployment, even in the Ambitious scenario. In CPs with coal and lignite capacities, they continue to represent a relevant share in total power generation and hydropower or interconnections provide additional flexibility (even in the Fragmented market scenario, which considers limited cross-border interconnection).

- ✓ Necessary investments in new flexible solutions are low in 2040, despite the coal and lignite phase-out envisioned in almost all CPs. Interconnection capacities are the main provider of flexibility at the CP level, allowing to mutualise flexibility resources among CPs and with EU MSs. Storage capacities are relevant in CPs where the RES shares are highest (Montenegro, Kosovo* and North Macedonia) while gas power generation assets are particularly necessary in CPs who lack generation capacities to meet the national demand (Ukraine, Moldova, Serbia, Kosovo*, Georgia by 2040).

- ✓ Market integration of regional power systems decreases the need for investments in flexibility solutions and drives down CO2 emissions. Such regional cooperation facilitates RES integration at lower costs and reduces congestions between CPs and with neighbouring interconnected countries. The impact of market integration on flexibility capacities is depicted in Figure 6 for the Ambitious 2040 scenario.

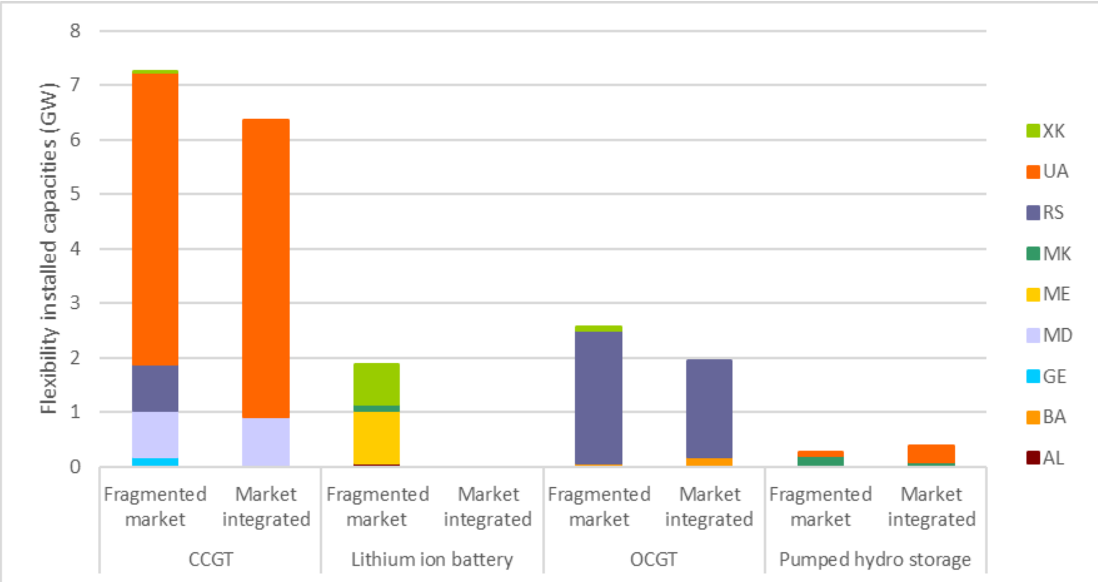

Figure 6 - Additional flexibility capacities required in the Energy Community for the Ambitious 2040 scenario. Comparison between Fragmented Market and Integrated Market configurations.

1 Introduction and report structure

Objective and scope of the report

This report is part of the 'Study on flexibility options to support decarbonization in the Energy Community'. It builds upon the analysis of technical and non-technical sources of flexibility (Task1) and covers the evaluation of existing and future flexibility needs and solutions (Task 2 and 3). The insights of the present report build the foundation for recommendations on the optimal set of solutions (Task 4) and on recommendations to the Contracting Parties on legal, regulatory and institutional frameworks (Task 5).

The first objective of this report's analysis is to provide information on the current utilization of existing flexibility solutions in the Energy Community. It includes an estimation of existing capacities of flexibility solutions that continue to exist by 2030 and 2040. This quantification serves as a basis for the subsequent assessment of the future needs for additional flexibility solutions. The second objective is to present the future flexibility needs and determine cost-optimal portfolios of flexibility solutions at the 2030- and 2040-time horizons, under several assumptions in terms of variable RES deployment, national coal phase-out strategies, and with different levels of interconnection capacity for all individual Contracting Parties (CPs) of the Energy Community.

Structure of this report

Chapter 2 contains the evaluation of existing flexibility solutions, their current use and their availability by 2030/2040. This is followed by an introduction of the prospective scenarios, their overall philosophy, main assumptions and country-specific hypotheses (Chapter 3). Chapter 4 introduces the concept of flexibility needs at the different timescales (daily, weekly and annual) and provides a quantification of the flexibility needs in 2030 and 2040 for all scenarios. Chapter 5 details the modelling approach to determine the cost-optimal flexibility portfolios for the CPs of the Energy Community and presents the associated set of modelling assumptions. Finally, Chapter 6 provides the identified optimal mix of flexibility solutions for all scenarios and future time horizons considered in the study, distinguished by CP. Country-specific results are available in the Annex.

Methodology

The approach for this report follows a chronological logic:

- ✓ The existing flexibility solutions are identified, and their current utilisation.
- ✓ The prospective scenarios are defined to depict the 2030 and 2040 power system landscapes with different ambition levels of variable RES deployment for all Contracting Parties. Scenario assumptions are validated by stakeholders from CPs and the ECS making them more robust, and valuing the significant data collection efforts undertaken in the study. For these scenarios, future flexibility needs are quantified on daily, weekly and annual timescales.
- ✓ Combining the two first phases, the available flexibility solutions are identified and characterized (techno-economic parameters).
- ✓ Based on a comprehensive electricity system modelling approach with the Artelys Crystal Super Grid model (coverings the CPs + the neighbouring EU MSs), a joint optimisation of investments and dispatch is conducted to define the optimal portfolios of flexibility solutions, reveal synergies between flexibility solutions and identify their contribution to meet the flexibility needs.

2 Evaluation of flexibility sources currently used in the Contracting Parties

This section presents the existing flexibility sources in 2020 in the Energy Community that allow to balance supply and demand at the daily, weekly and annual timescales (intra-hourly level is not included). It comprises an in-depth analysis of three categories of flexibility solutions for each CP:

- ✓ Flexible power generation. If relevant and data being available, these assets are analysed highlighting their capacity factors and ramp rates.
- ✓ Storage capacities. The installed capacities of storage assets, such as hydro reservoirs, pump hydro storages or batteries. Storage level profiles are presented when possible.
- ✓ Cross-border electricity interconnections. This section comprises the existing interconnection capacities and the analysis of cross-border flows and congestion hours[8].

This section also includes an estimation of the flexibility solutions that are expected to still exist by 2030 and 2040 which serves as a basis for the subsequent assessment of the future needs for additional flexibility solutions. It should be noted that hypotheses on the evolution of other/additional capacities are not described in this section. See section 3 for the scenario definition and more specifically section 3.3 for country specific assumptions.

The sources of the presented information are derived from public data (IEA and ENTSO-E Transparency Platform), previous studies from the Energy Community Secretariat (ECS) and exchanges with stakeholders.

2.1 Albania

Summary of existing flexibilities

Table 1 - Summary of existing flexibilities in Albania

Albania (AL)	Current	Residual	
	2020	2030	2040
Flexible power generation	1 807 MW of hydroelectric reservoir capacity		
Storage	1 807 MW of power capacity and 570 GWh of storage capacity of hydroelectric reservoirs.		
Interconnections[9]	941 MW for import 900 MW for export		

Flexible power generation

In 2020, Albania's generation mix is (almost) completely based on hydro power as illustrated in Figure 7. The associated installed capacities are summarized in Table 2.

[8] To calculate the congestion hours, cross-border (physical) flows were used, which do not correspond to commercial flows. Depending on the regions, it could also include loop flows. However, they can give a first approximation of the use and congestion hours of interconnections. In the analysis, the assumption was made that available net transfer capacity (NTC, referring to the available capacity for commercial purposes) was constant over the year. An interconnector is considered as presenting congestion when physical flows exceed 99% of the NTC.

[9] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.

Table 2 - Installed capacities (MW) per technology in Albania[10]

Technology	Installed capacities (MW)
Hydro Run-of-river	580
Hydro Reservoir	1 807
PV	21

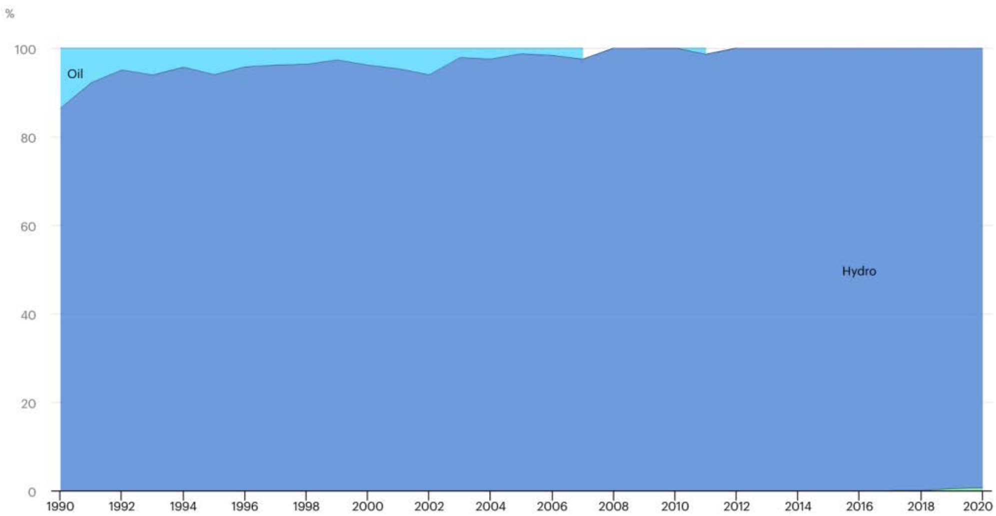

Figure 7 - Electricity generation by source in Albania[11]

No historical hourly timeseries of the flexible power generation assets (hydro reservoirs in this case) are available or were provided for the purpose of the study.

Storage

The available hydroelectric reservoir storage is estimated at 570 GWh.[12] No other storage capacities (batteries or PHS) are installed in the Albanian power sector so far.

Cross-border interconnections

Net transfer capacities

In 2020, Albania is interconnected with two CPs and one EU MSs (Montenegro, Kosovo* and Greece) for a total NTC of 941 MW for the import's direction and 900 MW for the export's direction, as described in Table 3.

Table 3 - Indicative (maximum) NTC values at Albanian borders[13]

Borders	Import (MW)	Export (MW)
Albania - Greece	250	250
Albania - Kosovo*	250	250
Albania - Montenegro	441	400
TOTAL	941	900

[10] Albanian Energy Regulatory Authority
[11] https://www.iea.org/countries/albania
[12] TYNDP 2020
[13] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties

Cross-border flows

Physical flows were extracted from the ENTSO-E Transparency Platform for the year 2020. Albania's physical flows equal 3.2 TWh of imports and 1 TWh of exports. Main importing flows come from Montenegro. On the other hand, main exporting flows are directed to Greece. As Albania's mix is exclusively relying on hydro, the exchange flows are seasonal, with a higher share in winter. Monthly cross-border flows are depicted in Figure 8.

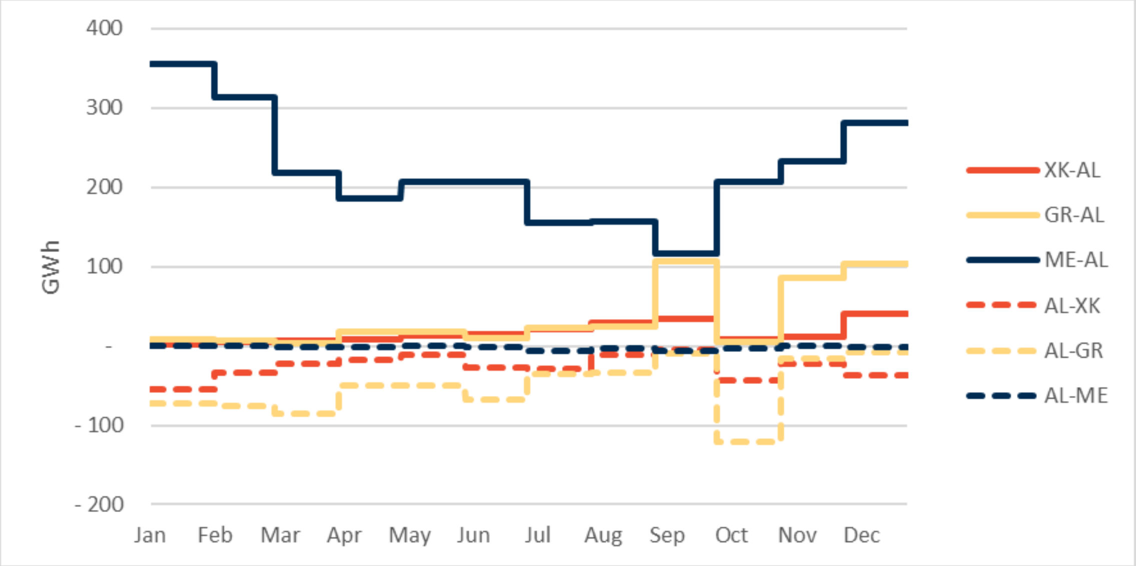

Figure 8 - Monthly cross-border physical flows in Albania (GWh) in 2020[14]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[15]

The estimated average use of interconnection and share of congestions hours are presented in Table 4. The import direction from Montenegro is the interconnection that is used the most, showing a high average use (64%). The line is congested during more than 20% of the year (21% in 2020).

Table 4 - Interconnections use and congested times in Albania in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congestion hours
AL-KS	14%	0%
KS-AL	9%	0%
AL-GR	28%	3%
GR-AL	18%	4%
AL-ME	1%	0%
ME-AL	64%	21%

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[16], end-of-life of the oldest hydro reservoir plant is 2055 (Vau I Dejes). Thus, existing hydro reservoir capacities are estimated to remain at a similar level (1 807 MW of capacity and 570GWh of reservoir storage) in 2030 and 2040.

[14] ENTSO-E Transparency Platform
[15] See footnote 8
[16] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community

2.2 Bosnia and Herzegovina

Summary of existing flexibilities

Table 5 - Summary of existing flexibilities in Bosnia and Herzegovina

Bosnia and Herzegovina (BA)	Current 2020	Residual 2030	Residual 2040
Flexible power generation	1 456 MW of hydroelectric reservoir capacity		
	2 065 MW of lignite capacity	1 353 MW of lignite capacity	600 MW of lignite capacity
Storage	1 456 MW of power capacity and 1 711 GWh of storage capacity of hydroelectric reservoir 440 MW power capacity and 3.4 GWh of storage capacity of PHS		
Interconnections[17]	2 100 MW for import 2 100 MW for export		

Flexible power generation

In 2020, Bosnia and Herzegovina's electricity production mix is shared between lignite (around 70%) and hydro (around 25%) as can be seen in Figure 9.

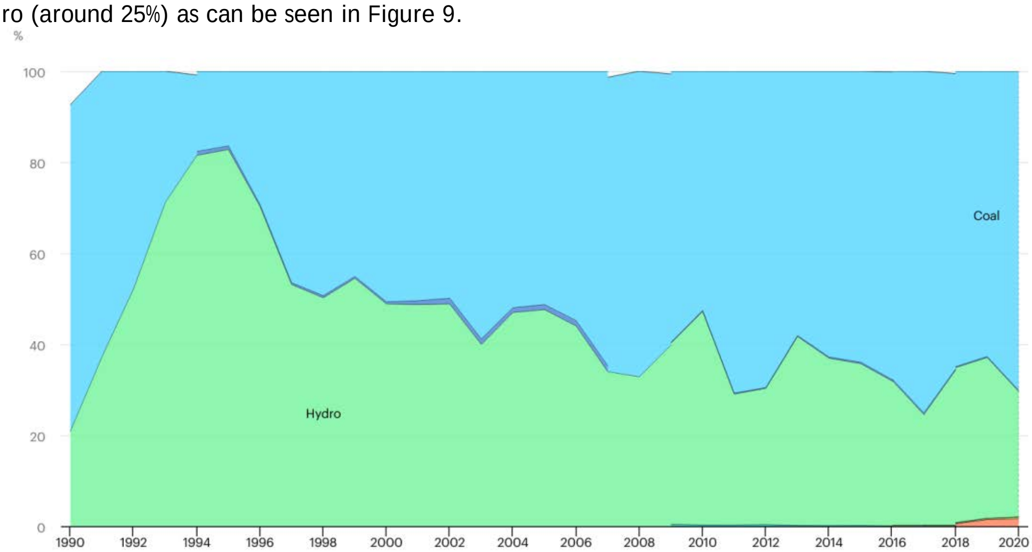

Figure 9 - Electricity generation by source in Bosnia and Herzegovina[18]

The associated installed capacities are summarized in Table 6.

Table 6 - Installed capacities (MW) per technology in Bosnia and Herzegovina[19]

	Installed capacities (MW)
Lignite	2065
Hydro Run-of-river	269
Hydro Reservoir	1 456
Hydro Pumped Storage	440
Biomass	2
Wind onshore	87
PV	35

[17] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.
[18] https://www.iea.org/countries/bosnia-and-herzegovina
[19] Ministry of Foreign Trade and Economic Relations of Bosnia and Herzegovina

Lignite capacities are used as a base load all over the year as can be depicted in Figure 10. Their capacity factor in 2020 is 58%.

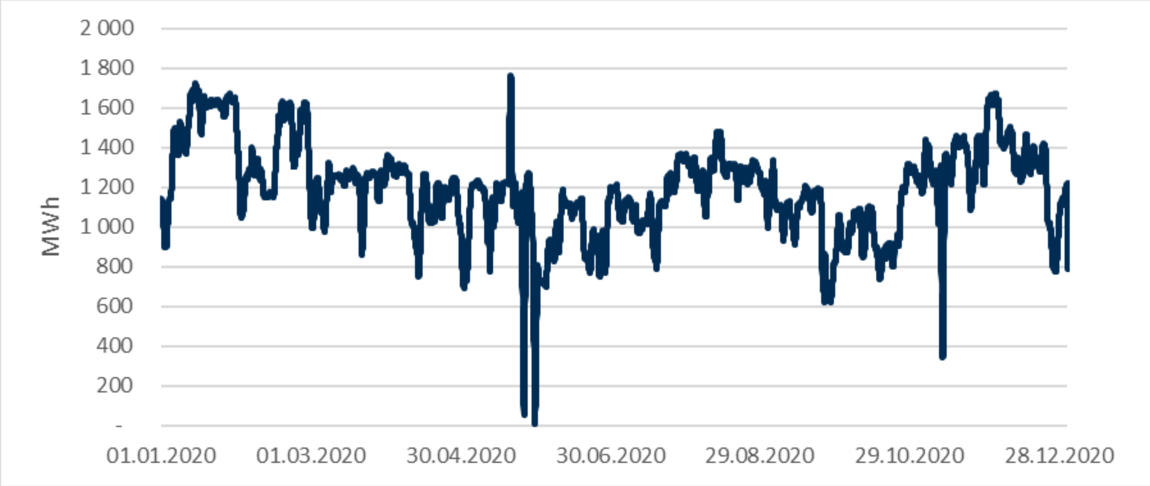

Figure 10 - Lignite power generation (daily average) in 2020 in Bosnia and Herzegovina[20]

Hydro reservoir generation have seasonal patterns, as they are dependent on inflows (Figure 11). Their capacity factor over the year 2020 is 32%. The hydro reservoirs show quite an important reactivity with an observed ramp rate of 60% of maximum capacity per hour.

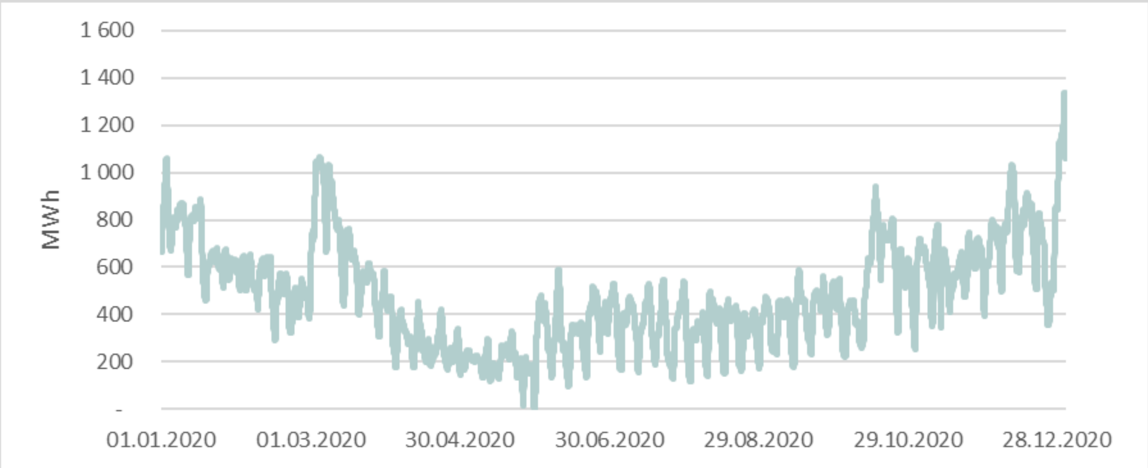

Figure 11 - Hydro reservoir power generation (daily average) in 2020 in Bosnia and Herzegovina [21]

Storage

The available hydroelectric reservoirs storage is estimated of 1 711 GWh. There is also one existing PHS plant of 440 MW of capacity and 3.43 GWh of storage capacity.[22] No other storage capacities (batteries) are installed.

Cross-border interconnections

Installed capacities

Bosnia Herzegovina is interconnected with two CPs and one EU MS (Croatia, Montenegro and Serbia) for a total NTC of 2 100 MW in both import’s and export’s directions, as described in Table 7.

[20] ENTSO-E Transparency Platform
[21] ENTSO-E Transparency Platform
[22] Ministry of Foreign Trade and Economic Relations of Bosnia and Herzegovina

Table 7 - Indicative (maximum) NTC values at BiH borders[23]

Borders	Import (MW)	Export (MW)
BiH - Croatia	1 000	1 000
BiH - Montenegro	500	500
BiH - Serbia	600	600
TOTAL	2 100	2 100

Cross-border flows

Cross-border flows in 2020 are dominated by exports, with net exports accounting for 3.6 TWh. Exports accounted for 5.4 TWh, and imports from neighbours to 1.8 TWh. Most of the export's flows go to Montenegro while Croatia is the main provider of imports to BA. Monthly cross-border flows are depicted in Figure 12.

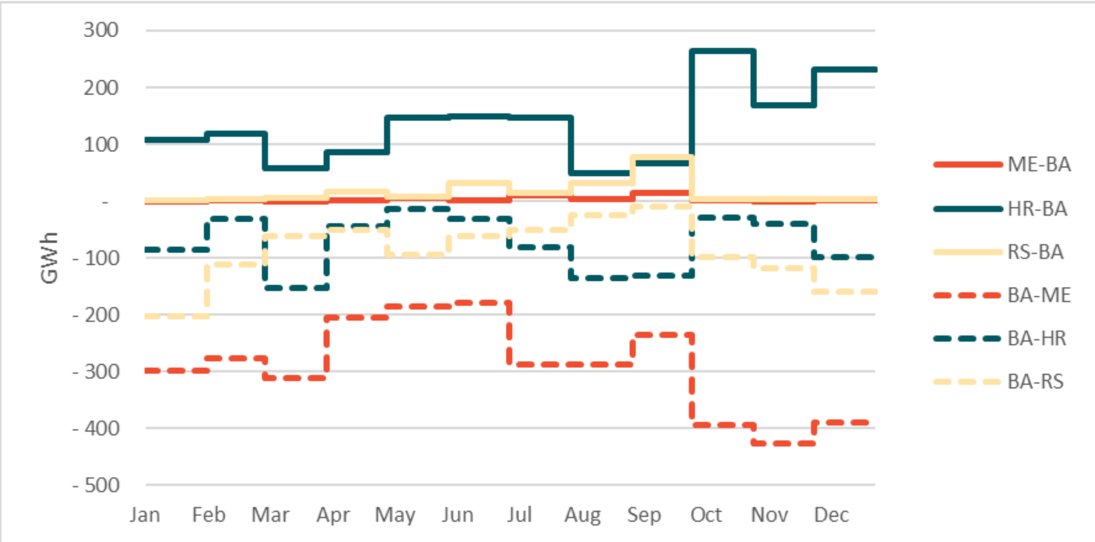

Figure 12 - Monthly cross-border physical flows in Bosnia and Herzegovina (GWh) in 2020[24]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[25]

Estimated average use of interconnections and share of congestions hours are presented in Table 8. The export direction towards Montenegro is the most solicited, showing a high average use (70%) and important congestion over the year (30% of the time).

[23] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties
[24] ENTSO-E Transparency Platform
[25] See footnote 8

Table 8 - Interconnections use and congested times in Bosnia and Herzegovina in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
ME-BA	1%	0%
BA-ME	70%	30%
HR-BA	18%	0%
BA-HR	10%	0%
RS-BA	4%	0%
BA-RS	20%	0%

Residual capacities by 2030 and 2040

- ✓ According to the *A carbon pricing design for the Energy Community* study[26]:Several lignite power plants will reach their end-of-life by 2030 and 2040. In 2030, five lignite power plants are expected to close, for a total capacity of 736 MW. Three additional plants accounting for 753 MW will reach end-of-life by 2040. From existing supply, only two power plants will remain in 2040: Ugljevik (300 MW) and Stanari (300 MW)[27].
- ✓ Hydro reservoir capacities are projected to remain at a similar level (1 456 MW of capacity and 1 711 GWh of reservoir storage). The oldest hydro power plants will reach end-of-life after the horizon of this study.
- ✓ Regarding PHS, the installed capacity will remain at 440 MW of capacity and 3.4 GWh of storage capacity.

2.3 Georgia

Summary of existing flexibilities

Table 9 - Summary of existing flexibilities in Georgia

<table>
<tr><th rowspan="2">Georgia (GE)</th><th colspan="2">Current</th><th colspan="3">Residual</th></tr>
<tr><th colspan="2">2020</th><th colspan="2">2030</th><th>2040</th></tr>
<tr><td rowspan="2">Flexible power generation</td><td colspan="5">2 381 MW of hydroelectric reservoir capacity
13 MW of coal capacity
485 MW of CCGT</td></tr>
<tr><td colspan="3">682 MW of OCGT</td><td colspan="2">110 MW of OCGT</td></tr>
<tr><td>Storage</td><td colspan="5">2 381 MW of power capacity and 950 GWh of storage capacity of hydroelectric reservoirs</td></tr>
<tr><td>Interconnections[28]</td><td>1 270 MW for import
1 270 MW for export</td><td>or[29]</td><td>1 330 MW for import
1 330 MW for export</td><td>or</td><td>150 MW for import
150 MW for export</td></tr>
</table>

Flexible power generation

In 2020, Georgia's electricity production mix is shared between hydro (around 75%) and natural gas (around 25%) as can be seen in Figure 13.

[26] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[27] This analysis does not consider the construction of Tuzla Unit 7 project, nor any life-extension works in existing lignite units.
[28] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.
[29] Synchronous operation is respectively possible only with Russia, with Azerbaijan or with Armenia (not all at the same time)

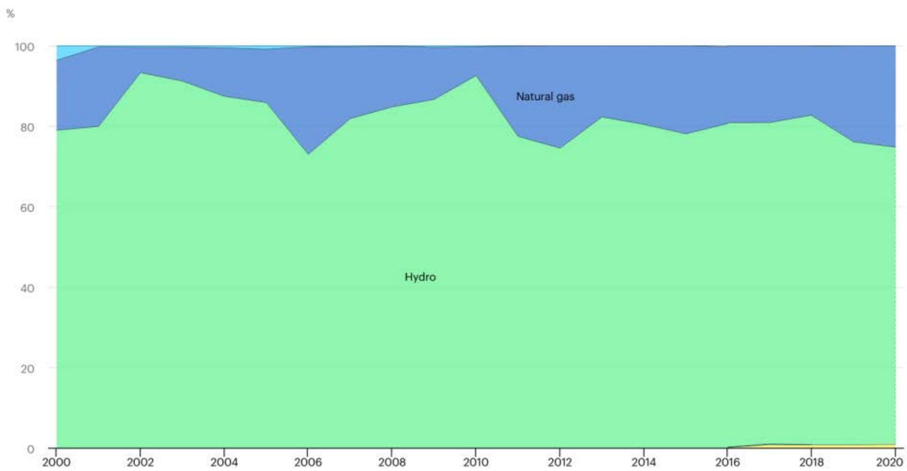

Figure 13 - Electricity generation by source in Georgia[30]

The associated installed capacities are summarized in Table 10.

Table 10 - Installed capacities (MW) per technology in Georgia[31]

Technology	Installed capacities (MW)
Coal	13
Gas OCGT	682
Gas CCGT	485
Hydro Run-of-river	969
Hydro Reservoir	2 381
Wind onshore	21
Solar	5

Georgian's supply is dominated by hydro production, which is mostly occurring during the summer season. Gas fills in the times where hydropower is not sufficient and this occurs on a broad window (from September to May), as can be depicted in Figure 14.

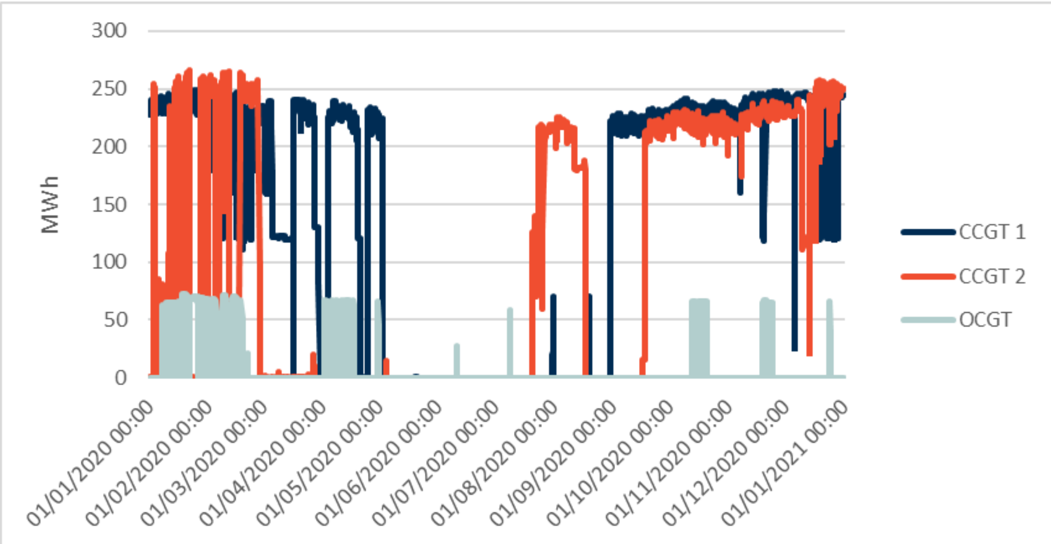

Figure 14 - Fossil gas power generation (MWh) in 2020 in Georgia[32]

[30] https://www.iea.org/countries/georgia
[31] Georgian State Electrosystem
[32] ENTSOE Transparency platform

Storage

The available hydroelectric reservoirs storage is estimated of 950 GWh.[33] No other storage capacities (batteries or PHS) are currently installed.

Cross-border interconnections

Installed capacities

Georgia is interconnected with four countries (Armenia, Azerbaijan, Russia and Turkey) for a total NTC of 2 050 MW in both import's and export's directions, as described in Table 11. However, due to its location between three synchronous zones, it is not possible to use the total cross-border capacity simultaneously.

Table 11 - Indicative (maximum) NTC values at Georgian borders[34]

Borders	Import (MW)	Export (MW)
Georgia - Armenia	150	150
Georgia - Azerbaijan	630	630
Georgia - Turkey (HVDC)	700	700
Georgia - Russia	570	570
TOTAL	2 050	2 050

Cross-border flows

Georgia's cross-border flows have been dominated by imports in the past five years, with 1 600 GWh/year of average imports and 400 GWh/year of exports to neighbouring countries. The flows patterns are seasonal, with imports occurring during winter when hydro production is low, and exports in summer during the period of high hydro generation, as depicted in Figure 15.

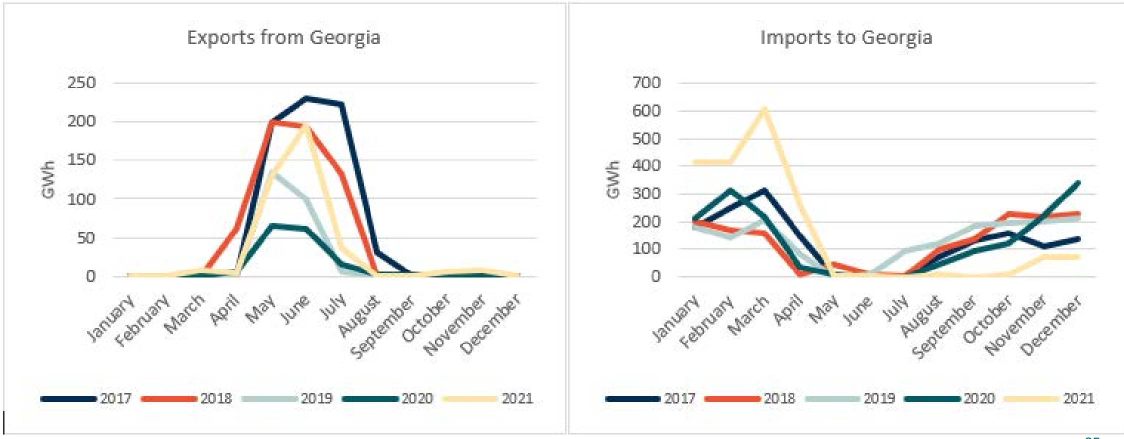

Figure 15 - Exports and imports with neighbouring countries in Georgia over the past 5 years (2017-2021)[35]

Azerbaijan is on average the biggest provider of electricity supply, followed by Russia and Turkey at can be depicted with monthly flows in 2020 on Figure 16.

[33] Georgian State Electrosystem
[34] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties
[35] Georgian State Electrosystem

Congestion hours

Congestion hours were not possible to assess as hourly cross-border flows were not made publicly available.

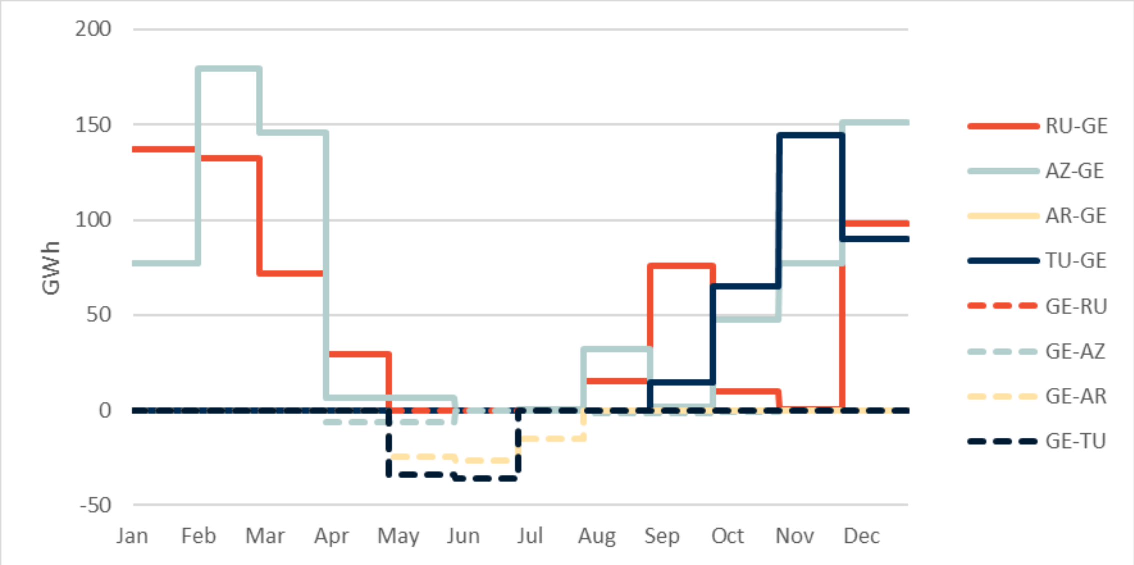

Figure 16 - Monthly imports and exports (GWh) in Georgia in 2020[36]. Exports are depicted as positive values, and imports as negative values.

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[37]:

- ✓ The thermal coal power plant of 13 MW reaches its end-of-life in 2045, remaining operational in the 2030 and 2040 horizons.
- ✓ Two OCGT power plants reach their end-of-life in 2031, reducing the country's capacities from 680 MW to 110 MW.
- ✓ In terms of hydroelectric capacities, the reservoirs will remain operational up to 2045. First capacities reaching end-of-life in 2040 concern run-of-river power plants that were installed in the country in the early stage.

2.4 Kosovo*

Summary of existing flexibilities

Table 12 - Summary of existing flexibilities in Kosovo*

Kosovo* (XK)	Current 2020	Residual 2030	Residual 2040
Flexible power generation	1 288 MW of lignite capacity	678 MW of lignite capacity	
Storage	-		
Interconnections[38]	1 166 MW for import 1 025 MW for export		

[36] Georgian State Electrosystem
[37] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[38] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.

Flexible power generation

In 2020, Kosovo*'s electricity production mix is almost exclusively lignite (around 95%) as can be seen in Figure 17. The associated installed capacities are summarized in Table 13.

Table 13 - Installed capacities (MW) per technology in Kosovo*[39]

Technology	Installed capacities (MW)
Lignite	1 288
Hydro Run-of-river	69
Hydro Reservoir	32
Biomass	2
Wind onshore	138
PV	11

No historical hourly timeseries of the flexible power generation assets (lignite and hydro reservoirs in this case) are available or were provided for the purpose of the study.

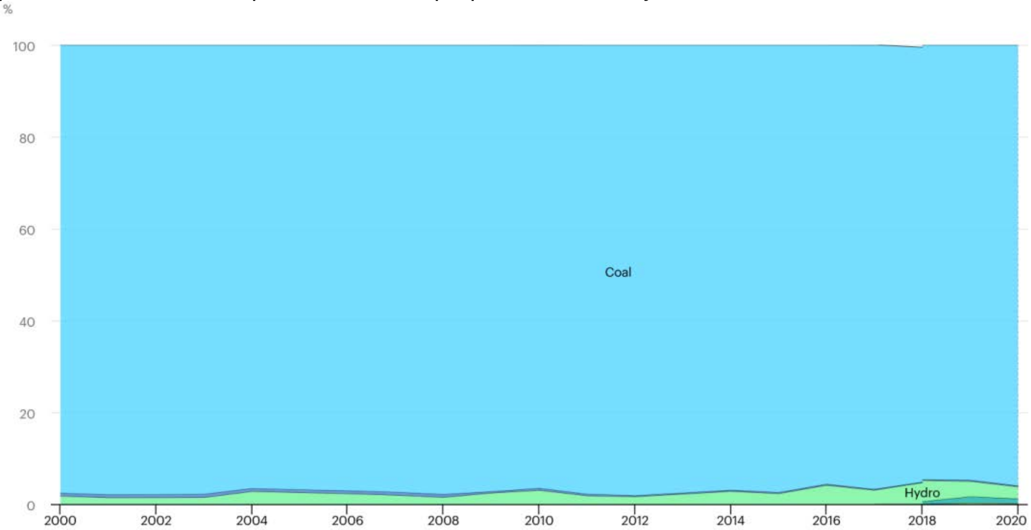

Figure 17 - Electricity generation by source in Kosovo*[40]

Storage

There is one hydro reservoir in Kosovo*, Ujmani dam, which has a power capacity of 32 MW. It is not considered as a flexibility mean in this report as its operation is linked with water supply for municipalities, for agricultural uses, and for thermal power plants. Thus, the hours of operation are constrained by the latter processes (must run hours)[41] . However, as shown in Figure 18, the Ujmani power plant generation shows a pattern of high production periods during early morning and late afternoon, and low generation during night-time hours.

[39] Ministry of Economy of Kosovo*
[40] https://www.iea.org/countries/kosovo
[41] Ministry of Economy of Kosovo*

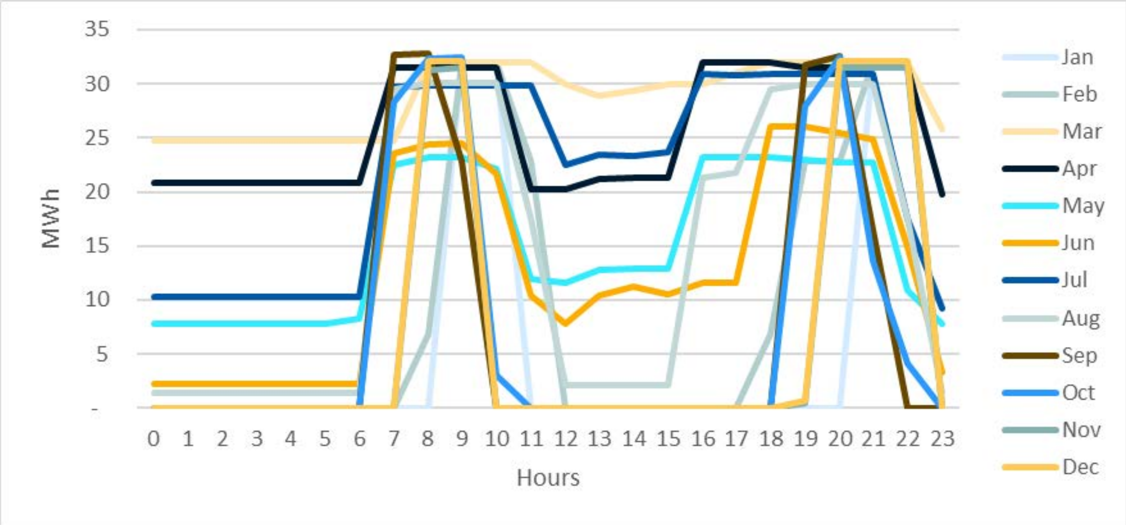

Figure 18 - Average hourly power production of Ujmani HPP in 2020, distinguished by month[42]

No other storage capacities (batteries or PHS) are installed.

Cross-border interconnections

Installed capacities

Kosovo* is interconnected with four CPs (Albania, Montenegro, North Macedonia and Serbia) for total imports NTC of 1 166 MW and total export NTC of 1025 MW, as described in Table 14.

Table 14 - Indicative (maximum) NTC values at Kosovar borders[43]

Borders	Import (MW)	Export (MW)
Kosovo* - Albania	250	250
Kosovo* - Montenegro	300	300
Kosovo* - N. Macedonia	291	150
Kosovo* - Serbia	325	325
TOTAL	1 166	1 025

Cross-border flows

Kosovo* flows are quite balanced, with a slight tender for exports in 2020. The cross-border flows in the latter direction account for 2.7 TWh while they represent 2.4 TWh in the import's direction. Most exports flows (75%) are directed to North Macedonia while 50% of the exchange in the import direction come from Serbia. There does not seem to be a specifically seasonal trend in the export nor the import direction. Monthly cross-border flows are depicted Figure 19.

[42] Ministry of Economy of Kosovo*
[43] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties

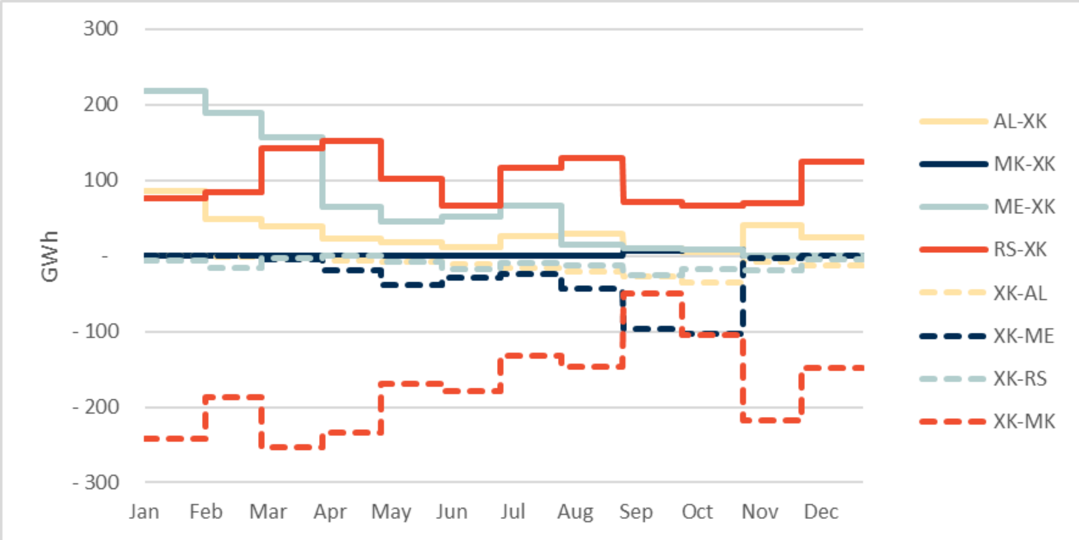

Figure 19 - Monthly cross-border physical flows in Kosovo* (GWh) in 2020[44]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[45]

Estimated average use of interconnection and share of congestions hours are presented in Table 15. The high level of cross-border flows from Serbia and to North Macedonia led to high uses of the interconnector (41% and 87% of average interconnector use, respectively). In the case of North Macedonia, where NTC are quite limited, the flows are most of the time exceeding the commercial limits, represented by 78% of the time of the year where the interconnection is congested.

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[46]:

- ✓ One unit of the Kosovo A lignite power plant is expected to be fully decommissioned by 2025, and the two others units will stop normal operation by 2028, and will remain as strategic reserves for winter months. The two units of the Kosovo B lignite power plant will remain in operation until 2043[47]. In total, the residual lignite capacities for normal operation are expected to equal 678 MW by 2030 and 2040.
- ✓ The Ujmani hydro reservoir plant will be operational for the horizon of this study.

Table 15 - Interconnections use and congested times in Kosovo* in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
XK-AL	7%	0%
AL-XK	17%	0%
XK-ME	14%	1%
ME-XK	28%	12%
XK-MK	87%	78%
MK-XK	1%	0%
XK-RS	5%	0%
RS-XK	41%	7%

[44] Ministry of Economy of Kosovo*
[45] See footnote 8
[46] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[47] Department of Energy, Ministry of Economy, Kosovo*

2.5 Moldova

Summary of existing flexibilities

Table 16 - Summary of existing flexibilities in Moldova

Moldova (MD)	Current	Residual	
	2020	2030	2040
Flexible power generation	800 MW of coal capacities		-
	1 321 MW of natural gas capacities		40 MW of natural gas capacities
Storage	-		
Interconnections[48]	800 MW for import 1 200 MW for export		

Flexible power generation

In 2020, Moldova's electricity production mix is almost exclusively natural gas (around 95%) as can be seen in Figure 20.

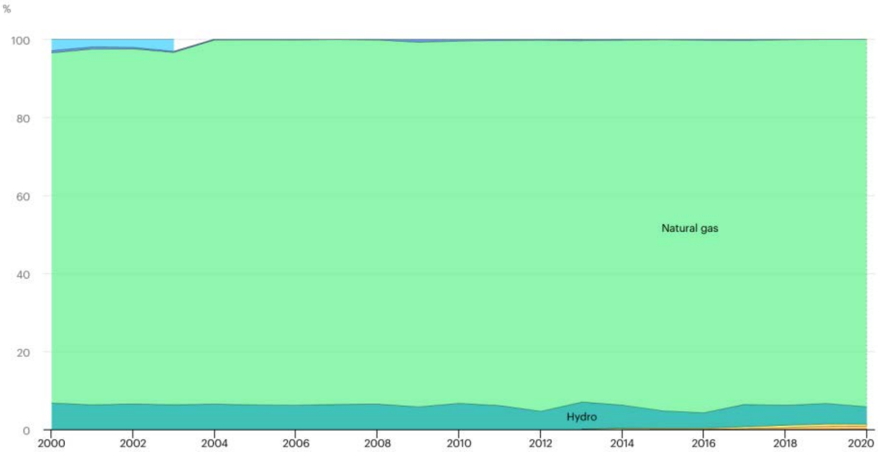

Figure 20 - Electricity generation by source in Moldova[49]

The associated installed capacities are summarized in Table 17.

Table 17 - Installed capacities (MW) per technology in Moldova[50]

Technology	Installed capacities (MW)
Coal	800
Manufactured gas	1 321
Hydro Run-of-river	64
Biomass	19
Wind onshore	29
PV	5

[48] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.
[49] https://www.iea.org/countries/republic-of-moldova
[50] SE Moldelectrica

400 MW of coal-based power plant is gas capable as well and currently operated on gas.[51] Fossil gas capacities are used as a base load all over the year as can be depicted in Figure 21. Their capacity factor in 2020 is 60%.

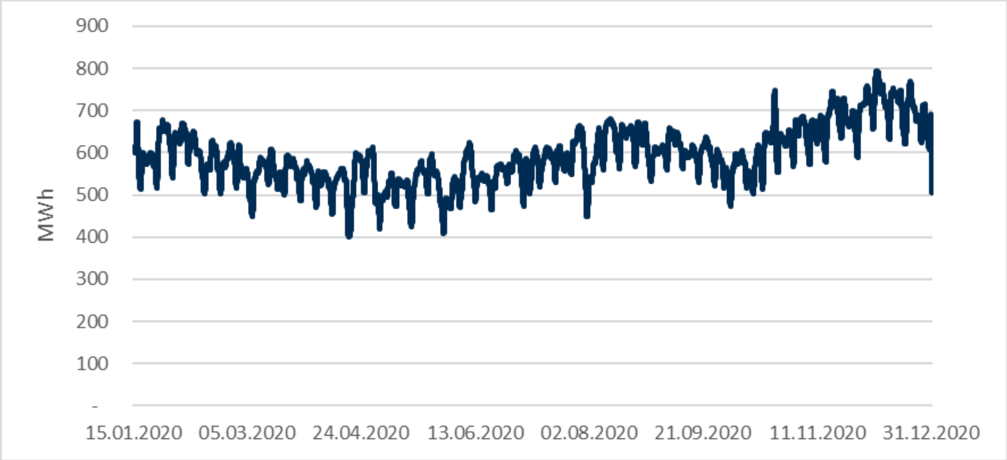

Figure 21 - Fossil gas power generation (daily average) in 2020 in Moldova[52]

Storage

No storage capacities (batteries, hydroelectric reservoirs or PHS) are currently installed.

Cross-border interconnections

Installed capacities

During 2020, Moldova's power system was still synchronized with the interconnected Russian power system (UPS/IPS) and only interconnected with Ukraine. The Ukraine interconnection has an estimated maximum cross-border capacity of 800 MW for imports and 1 200 MW for exports.

Cross-border flows

In 2020, cross-border flows are dominated by imports (227 GWh) from Ukraine, with exports representing less than half (90 GWh, however mostly transit/loop flows). Monthly cross-border flows are depicted Figure 22 and show a higher share of flows from Ukraine in the first months of the year (January-March).

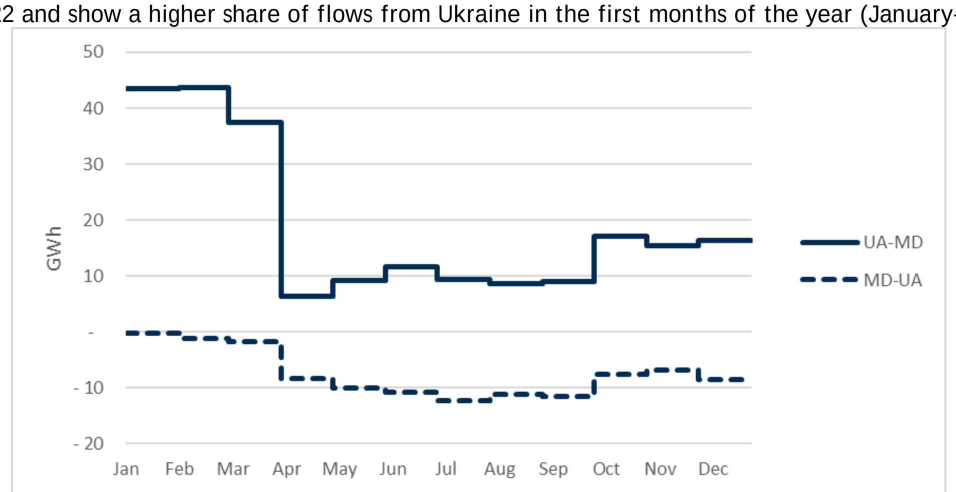

Figure 22 - Monthly cross-border physical flows in Moldova (GWh) in 2020[53]. Exports are depicted as positive values, and imports as negative values.

[51] SE Moldelectrica
[52] ENTSO-E Transparency Platform
[53] ENTSO-E Transparency Platform

Congestion hours[54]

Estimated average use of interconnection and share of congestions hours are presented in Table 18. The NTC between Moldova and Ukraine are sufficiently high to obtain low average use of the transmissions and no congested times.

Table 18 - Interconnections use and congested times in Moldova in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
MD-UA	0%	0%
UA-MD	7%	0%

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[55], the coal power plants will come to the end of their lifetime and be decommissioned between 2033 and 2036. Most natural gas thermal plants are also planned to be decommissioned between 2031 and 2036, leaving around 40 MW of capacities in 2040.

2.6 Montenegro

Summary of existing flexibilities

Table 19 - Summary of existing flexibilities in Montenegro

<table>
<tr><th rowspan="2">Montenegro (ME)</th><th>Current</th><th colspan="2">Residual</th></tr>
<tr><th>2020</th><th>2030</th><th>2040</th></tr>
<tr><td rowspan="2">Flexible power generation</td><td colspan="3">684 MW of hydroelectric reservoir capacity</td></tr>
<tr><td>225 MW of lignite capacity</td><td colspan="2">-</td></tr>
<tr><td>Storage</td><td colspan="3">684 MW of power capacity and 460 GWh of storage capacity of hydroelectric reservoir</td></tr>
<tr><td>Interconnections[56]</td><td colspan="3">2 100 MW for import
2 041 MW for export</td></tr>
</table>

Flexible power generation

In 2020, Montenegro's electricity production mix is evenly shared by coal and hydro (around 45% each) and completed with wind (little less than 10%) as can be seen in Figure 23.

[54] See footnote 8
[55] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[56] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.

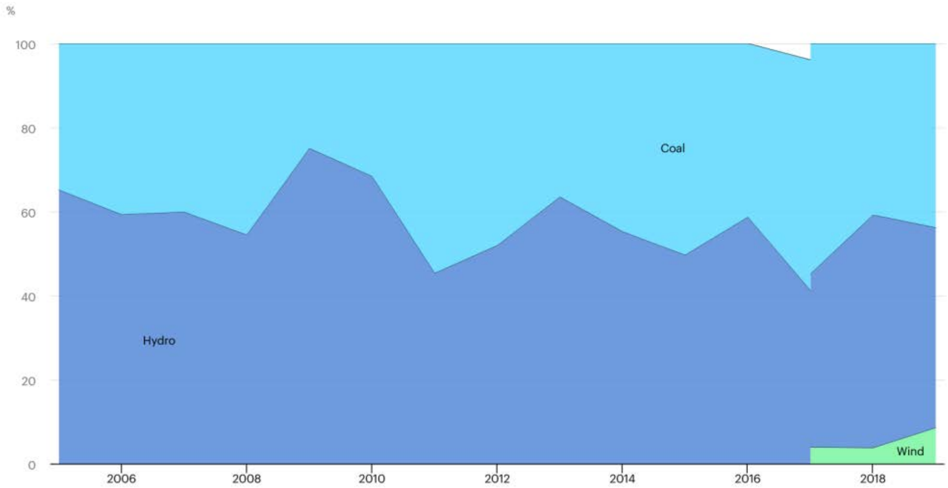

Figure 23 - Electricity generation by source in Montenegro[57]

The associated installed capacities are summarized in Table 20.

Table 20 - Installed capacities (MW) per technology in Montenegro[58]

Technology	Installed capacities (MW)
Lignite	225
Hydro Reservoir	680
Wind onshore	118

Lignite capacities (210 MW) are used as a base load most of the year as can be depicted on Figure 24. During year 2020, it was operated at its full capacity except during the month of April and May, for a capacity factor of 80% over the year.

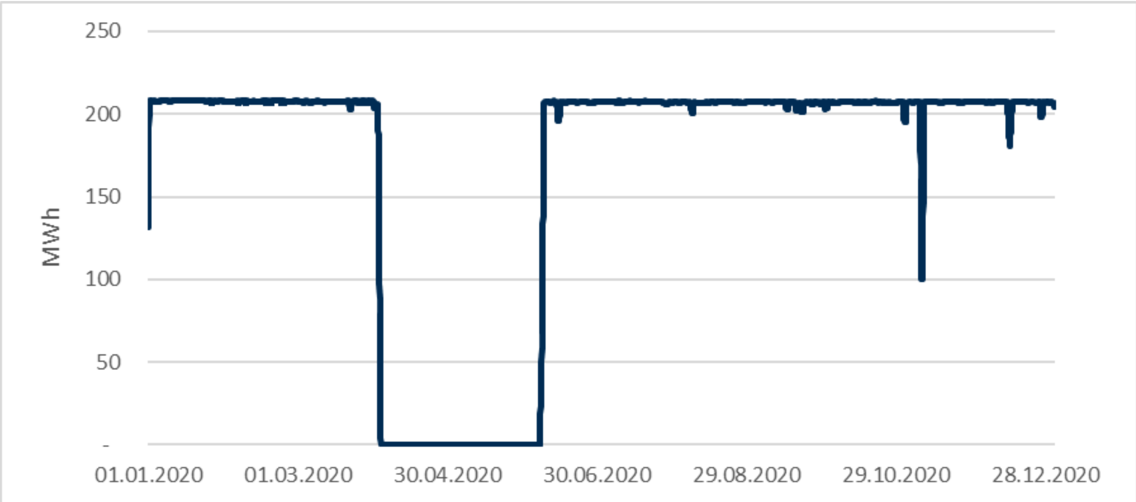

Figure 24 - Lignite power generation (daily average) throughout 2020 in Montenegro[59]

Hydropower capacities (run of river and reservoir accounting for a total of 680 MW) are used to complete the mix, with a seasonal pattern as can be seen on Figure 25. During year 2020, the capacity factor of hydroelectric power plants was of 22%. The observed ramp rate is of 60% of maximum capacity per hour.

[57] https://www.iea.org/countries/montenegro
[58] ENTSO-E Transparency platform & Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[59] ENTSO-E Transparency Platform

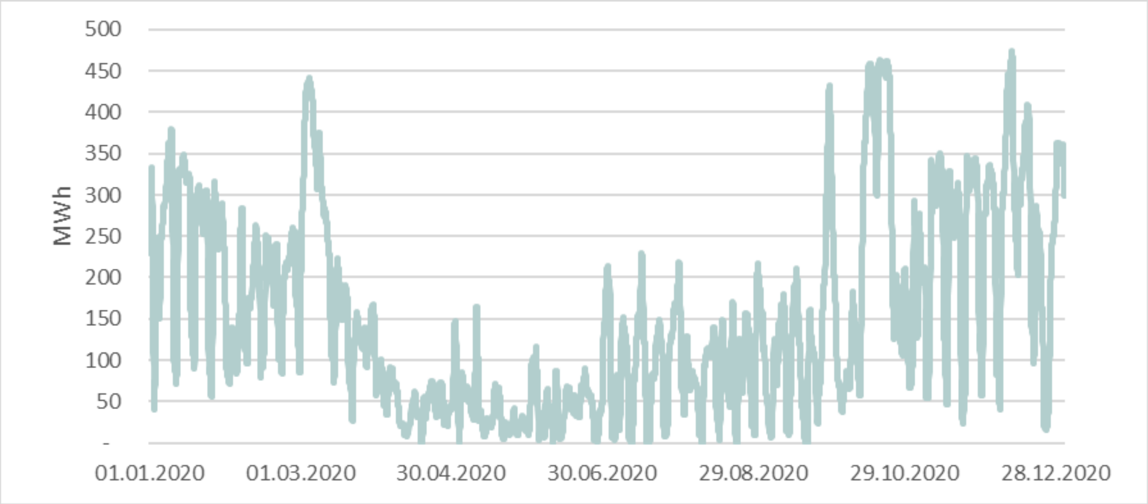

Figure 25 - Hydro (reservoir and run of river) power generation (daily average) in 2020 in Montenegro[60]

Storage

The hydroelectric reservoir power plants allow up to 460 GWh storage capacity[61], whose evolution over the year 2020 can be seen on Figure 26. The reservoir is contributing to flexibility on a seasonal pattern. Three main cycles are identifiable, during the end of autumn and winter and a larger one during summer. No other storage capacities (batteries or PHS) are currently installed.

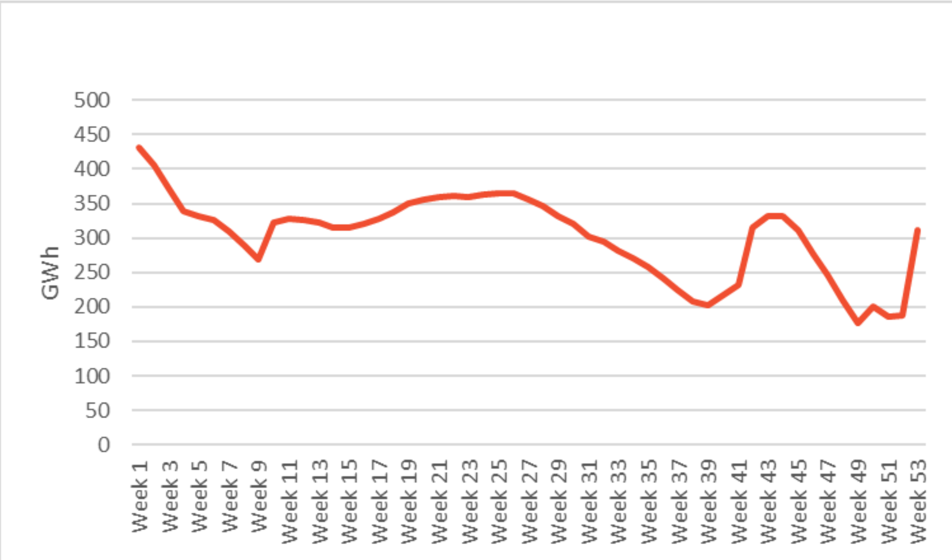

Figure 26 - Hydro reservoir storage level (weekly) of Montenegro over the year 2020[62]

Cross-border interconnections

Installed capacities

Montenegro is interconnected with four CPs and one EU MSs (Albania, Bosnia and Herzegovina, Italy, Kosovo* and Serbia) for a total import NTC of 2 100 MW and export NTC of 2 041 MW, as described in Table 21.

[60] ENTSO-E Transparency Platform
[61] ENTSO-E PEMMDB 2020
[62] ENTSO-E Transparency Platform

Table 21 - Indicative (maximum) NTC values at Montenegro borders[63]

Borders	Import (MW)	Export (MW)
Montenegro - Albania	400	441
Montenegro - Bosnia and Herzegovina	500	500
Montenegro - Italy	600	600
Montenegro - Kosovo*	300	300
Montenegro - Serbia	300	200
TOTAL	2 100	2 041

Cross-border flows

Monthly cross-border flows are depicted Figure 27. Montenegro is geographically central in the WB6 CPs. Significant power flows go through the country either for import/export or transit. Flows on the export direction account for 6.6 TWh, and on the import direction for 5.4 TWh. Thus, in total, export flows exceed import flows. Almost all interconnections are heavily solicited, with a higher share for the exports towards Albania (ME->AL) and imports from Bosnia (BA->ME).

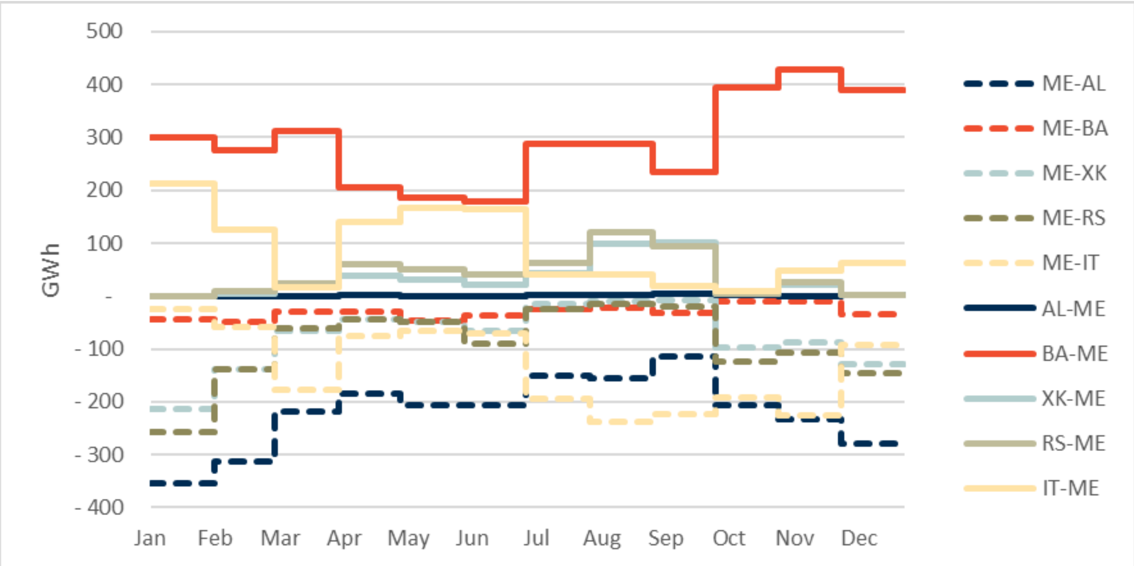

Figure 27 - Monthly cross-border physical flows in Montenegro (GWh) in 2020[64]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[65]

Estimated average use of interconnection and share of congestions hours are presented in Table 22. In the export direction, flows going to Albania and Serbia present the higher use of interconnection, with congestions estimated at around 25% over the year. On the other import direction, flows coming from Bosnia and Herzegovina are the most import, leading to a 70% average use of the interconnection and congestions estimated at 30% of time in 2020.

[63] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties
[64] ENTSO-E Transparency Platform
[65] See footnote 8

Table 22 - Interconnections use and congested times in Montenegro in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
ME-AL	64%	21%
ME-BA	9%	0%
ME-XK	33%	10%
ME-RS	43%	26%
ME-IT	31%	5%
AL-ME	0%	0%
BA-ME	70%	30%
XK-ME	15%	1%
RS-ME	18%	4%
IT-ME	20%	0%

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[66], the lignite power plant of Pljevlja is expected to be decommissioned before 2030[67], reducing to 0 all existing lignite capacity in 2030 and 2040. On the other hand, the hydroelectric reservoirs will remain operational up to 2050.

2.7 North Macedonia

Summary of existing flexibilities

Table 23 - Summary of existing flexibilities in North Macedonia

<table>
<tr><th rowspan="2">North Macedonia (MK)</th><th>Current</th><th colspan="2">Residual</th></tr>
<tr><th>2020</th><th>2030</th><th>2040</th></tr>
<tr><td rowspan="2">Flexible power generation</td><td colspan="3">539 MW of hydroelectric reservoir capacity
311 MW of CCGT</td></tr>
<tr><td colspan="2">829 MW of lignite capacity</td><td>-</td></tr>
<tr><td>Storage</td><td colspan="3">539 MW of power capacity and 609 GWh of storage capacity of hydroelectric reservoir</td></tr>
<tr><td>Interconnections[68]</td><td colspan="3">1 050 MW for import
991 MW for export</td></tr>
</table>

Flexible power generation

In 2020, North Macedonia's electricity production mix is dominated by coal (with 50% of production), followed by hydro (around 25%) and natural gas (around 20%) as can be seen in Figure 28.

[66] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[67] https://balkangreenenergynews.com/coal-power-plant-pljevlja-likely-to-be-shut-down-by-2030-montenegrin-prime-minister/
[68] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.

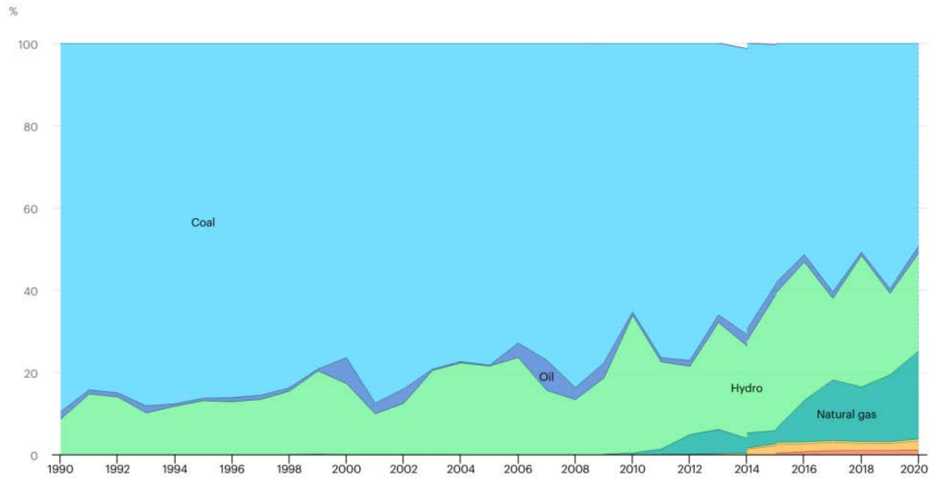

Figure 28 - Electricity generation by source in North Macedonia[69]

The associated installed capacities are summarized in Table 24.

Table 24 - Installed capacities (MW) per technology in North Macedonia[70]

Technology	Installed capacities (MW)
Lignite	829
Gas CCGT	311
Hydro Run-of-river	200
Hydro Reservoir	539
Biomass	16
Wind onshore	37
PV	17

Lignite and CCGT generation in 2020 are shown in Figure 29 and in Figure 30 respectively. Lignite generation shows higher variability, in comparison to Montenegro's, with several stop and starts along the year. Lignite capacity factor is 40% for this year. CCGTs show a peaking role during the first half of the year, and a seasonal base load during the second half. It's capacity factor for 2020 was 40% also.

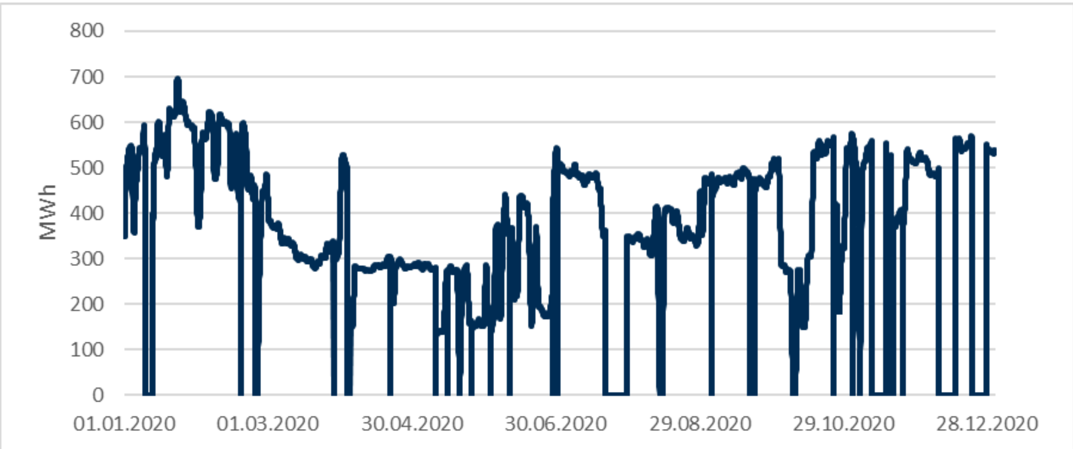

Figure 29 - Lignite power generation (daily average) in 2020 in North Macedonia[71]

[69] https://www.iea.org/countries/north-macedonia
[70] MEPSO Electricity Transmission System Operator of North Macedonia
[71] ENTSO-E Transparency Platform

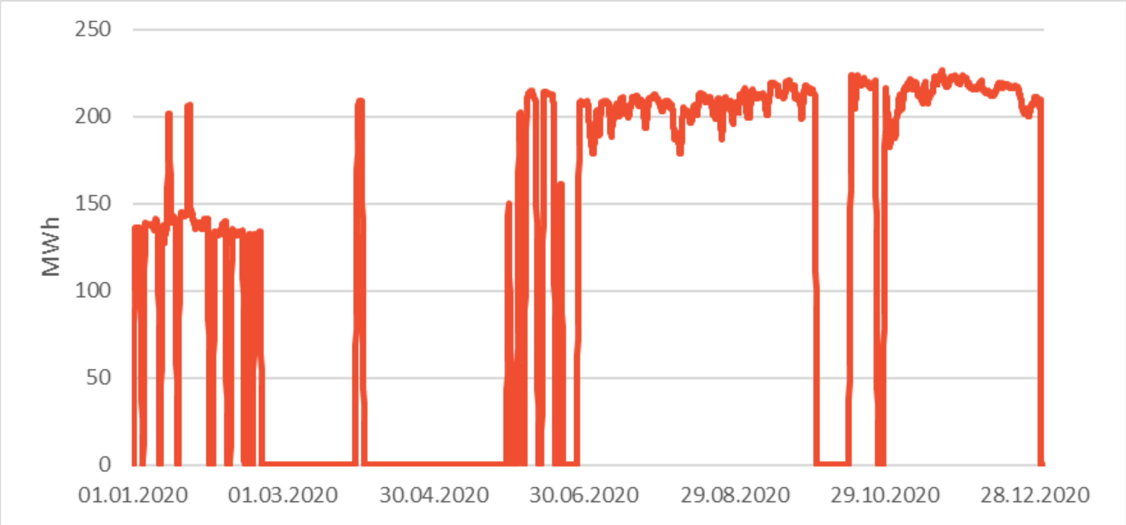

Figure 30 - CCGT power generation (daily average) in 2020 in North Macedonia[72]

Hydro reservoirs power plants produce all over the year with a more significant volume during the summer period (Figure 31). Their capacity factor over the year 2020 is 19% and observed ramp rate is of 40% of maximum capacity per hour.

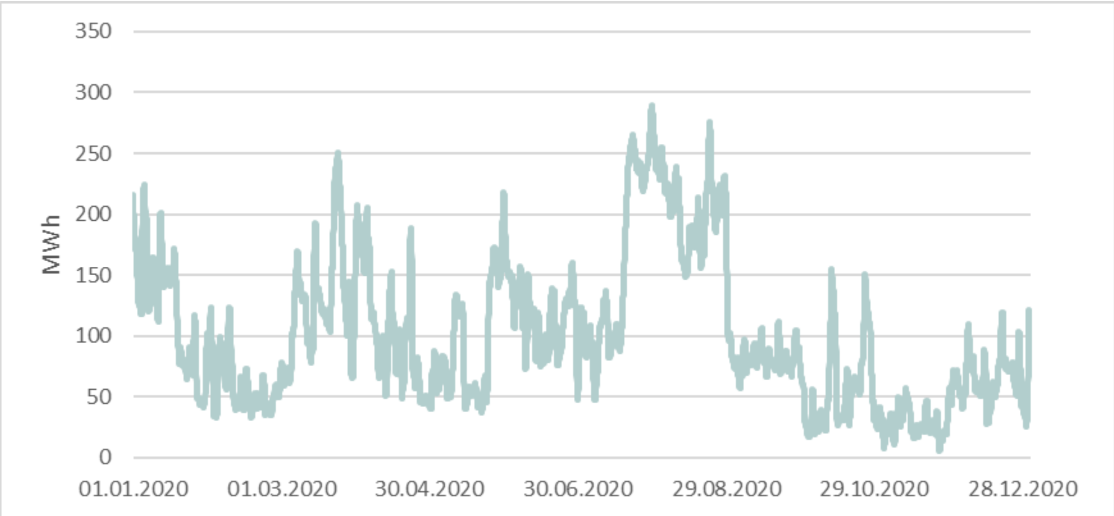

Figure 31 - Hydro reservoir power generation (daily average) in 2020 in North Macedonia[73]

Storage

The hydroelectric reservoirs have a storage capacity of 609 GWh. Their use in the years 2016-2020 are depicted Figure 32. The historical data show an important seasonality in the stock profile, filling the reservoirs at the end of winter and all along the spring period. The stored energy is used during the summer and autumn period.

[72] MEPSO Electricity Transmission System Operator of North Macedonia
[73] MEPSO Electricity Transmission System Operator of North Macedonia

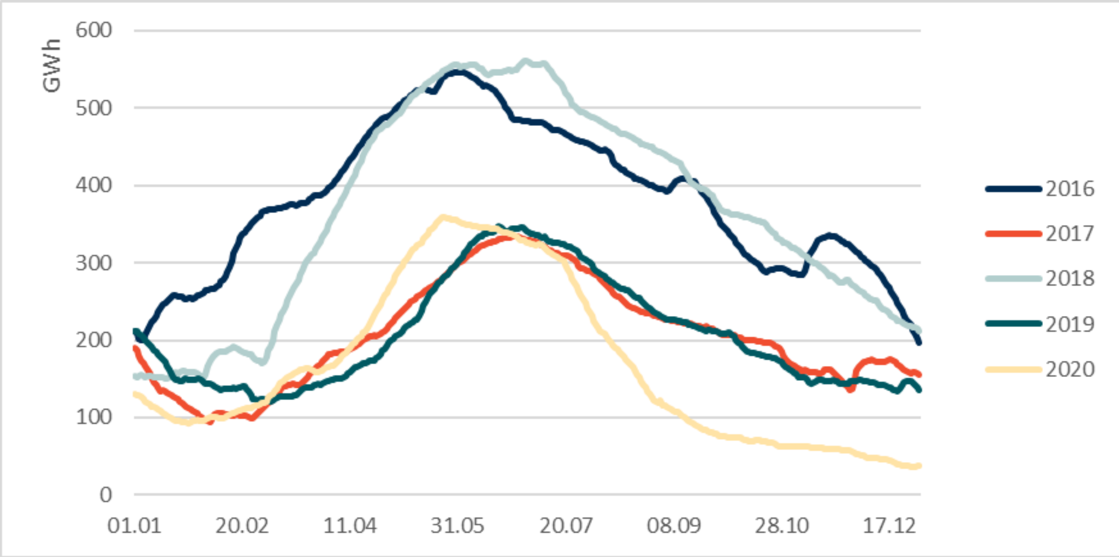

Figure 32 - Daily hydroelectric reservoir storage levels (GWh) over 5 years in North Macedonia

Cross-border interconnections

Installed capacities

North Macedonia is interconnected with two CPs and two EU MSs (Bulgaria, Greece, Kosovo* and Serbia) for a total import NTC of 1 050 MW and export NTC of 991 MW, as described in Table 25.

Table 25 - Indicative (maximum) NTC values at North Macedonia borders[74]

Borders	Import (MW)	Export (MW)
N. Macedonia - Bulgaria	250	150
N. Macedonia - Greece	350	300
N. Macedonia - Kosovo*	150	291
N. Macedonia - Serbia	300	250
TOTAL	1 050	991

Cross-border flows

Monthly cross-border flows are depicted Figure 33. Dominant flows are in the import's direction with 5.1 TWh in 2020, while the export's amounted to 2.8 TWh. The three main provider of these flows are (in order of highest magnitude) Kosovo*, Bulgaria and Serbia. On the other hand, most flows from the export direction go to Greece. Considering these flows, it seems that North Macedonia is a place for transit, at least from Kosovo* and Serbia towards Greece. Nonetheless, it also uses a high share of imports to supply its needs.

[74] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties

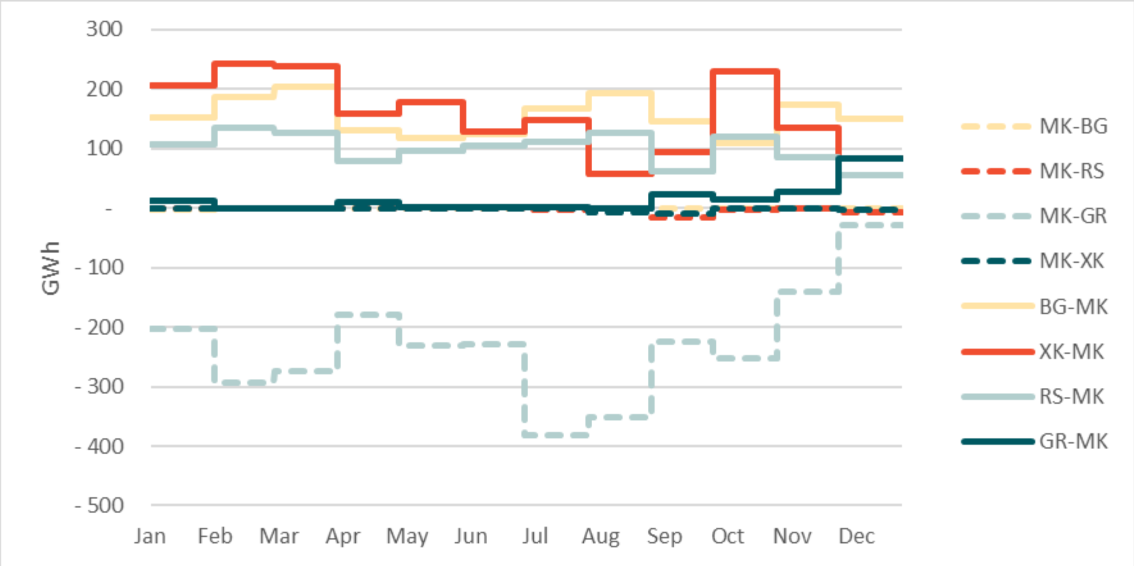

Figure 33 - Cross-border physical flows in North Macedonia (GWh) in 2020[75]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[76]

Estimated average use of interconnection and share of congestions hours are presented in Table 26. Three interconnections show very high uses and congested times: import from Kosovo* (XK->MK), and Bulgaria (BG->MK), and exports to Greece (MK->GR). In the import direction, the Kosovo*-North Macedonia line is quite small (150 MW), which could explain the high estimated share of congested times. The interconnection with Serbia also has a high use in the import direction but shows no congestion due to a higher capacity (300 MW).

Table 26 - Interconnections use and congested times in North Macedonia in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
MK-BG	0%	0%
BG-MK	76%	37%
MK-GR	74%	59%
GR-MK	6%	2%
MK-XK	1%	0%
XK-MK	84%	72%
MK-RS	1%	0%
RS-MK	46%	0%

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[77]:

- ✓ All currently installed lignite capacities are expected to be decommissioned between 2030 and 2033.
- ✓ Hydro and CCGT capacities will remain the same up to 2040.

[75] ENTSO-E Transparency Platform
[76] See footnote 8
[77] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community

2.8 Serbia

Summary of existing flexibilities

Table 27 - Summary of existing flexibilities in Serbia

Serbia (RS)	Current 2020	Residual 2030	Residual 2040
Flexible power generation	472 MW of hydroelectric reservoir capacity		
	4 437 MW of lignite capacity	4 073 MW of lignite capacity	
	255 MW of CCGT capacity	120 MW of CCGT capacity	-
Storage	472 MW of power capacity and 500 GWh of storage capacity of hydroelectric reservoir		
	639 MW of power capacity and 194 GWh of storage capacity of PHS		
Interconnections[78]	3 825 MW for import		
	4 025 MW for export		

Flexible power generation

In 2020, Serbia's electricity production mix is dominated by coal (with 70% of production), followed by hydro (around 25%) as can be seen in Figure 34.

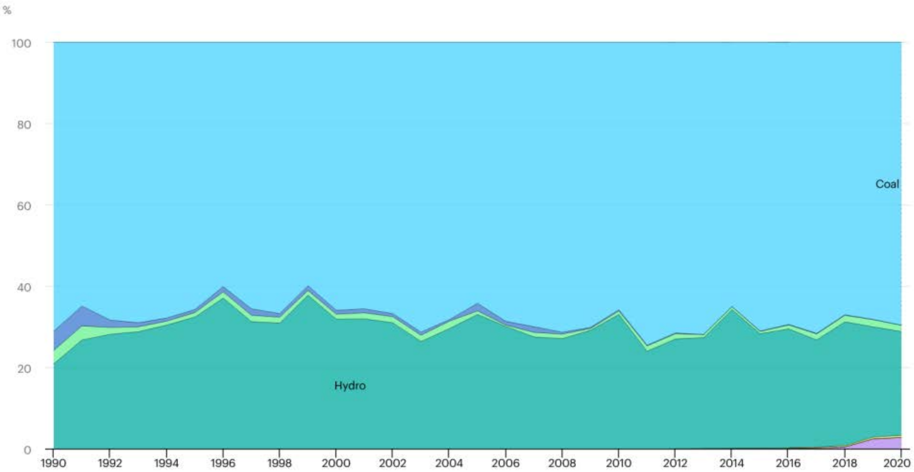

Figure 34 - Electricity generation by source in Serbia[79]

The associated installed capacities are summarized in Table 28.

Table 28 - Installed capacities (MW) per technology in Serbia[80]

Technology	Installed capacities (MW)
Lignite	4 437
Gas CCGT	255
Hydro Run-of-river	2 011
Hydro Reservoir	472
Hydro Pumped Storage	639
Biomass	8
Wind onshore	397

[78] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.
[79] https://www.iea.org/countries/serbia
[80] For fossil fuel plants: Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
For other plants: ENTSO-E Transparency Platform & PE EPS

PV	10
Other	25

Lignite capacities are used as a base load all over the year as can be depicted in Figure 35. Their capacity factor was 64% for 2020.

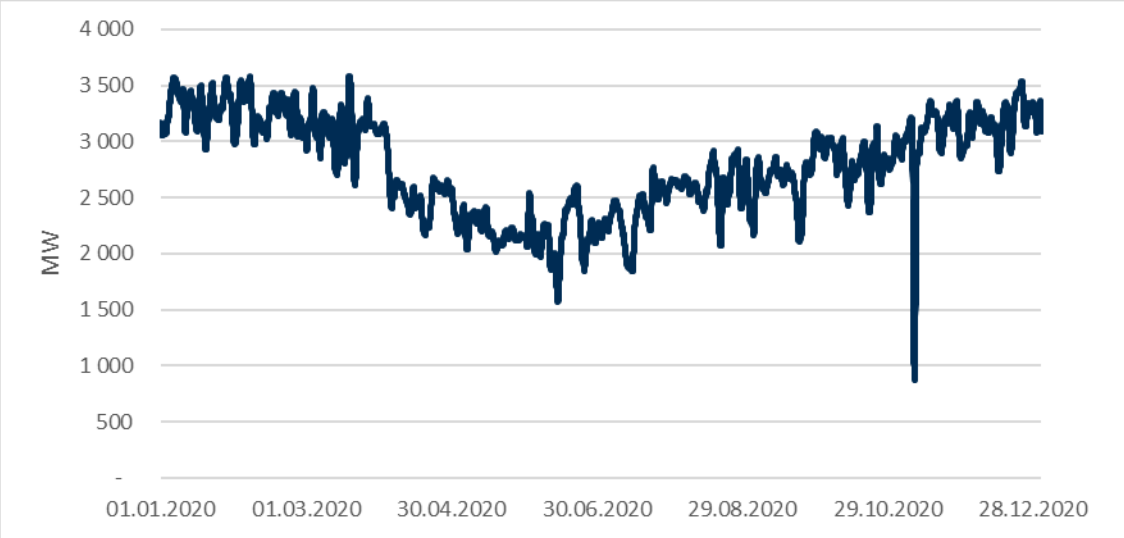

Figure 35 - Lignite power generation (daily average) in 2020 in Serbia[81]

Hydro power plants in Serbia are composed of hydro run-of-river and pondage plants on one hand and water reservoirs on the other. A pondage power plant has a small water storage behind the weir of run-of-the-river hydroelectric power plants. It can contribute to flexibility needs at a daily and weekly scale depending on its size. The hydro run-of-river and pondage power generation can be seen in Figure 36 and show production all over the year with peaks for specific periods. The capacity factor over the year 2020 is 48% and observed ramp rate is of 46% of maximum capacity per hour. Hydro water reservoirs generation is much more fluctuating and seem to be activated to meet load fluctuation at specific moments. The generation profiles are depicted Figure 37. The capacity factor over the year 2020 is quite low (15%) and observed ramp rate is of 66% of maximum capacity per hour.

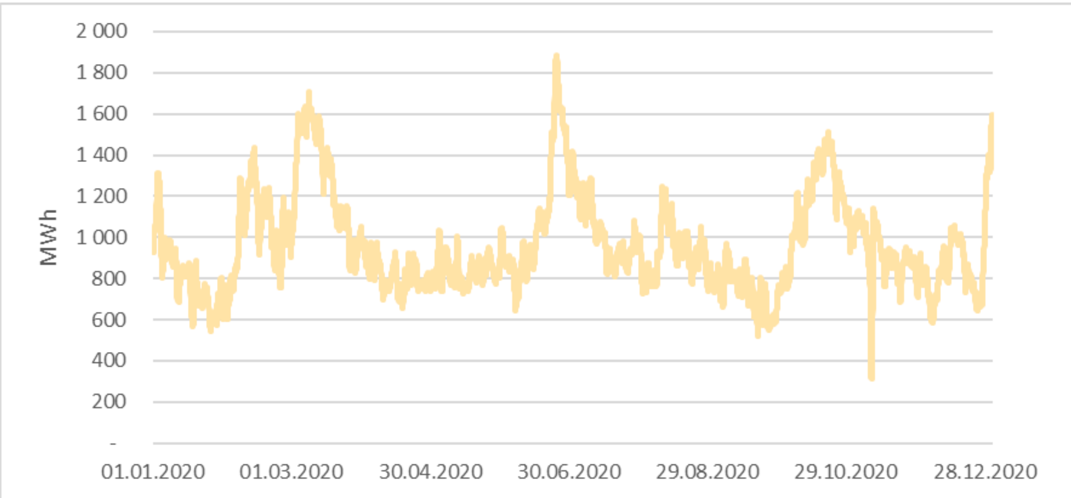

Figure 36 - Hydro run-of-river and poundage power generation (daily average) in 2020 in Serbia[82]

[81] ENTSO-E Transparency Platform
[82] ENTSO-E Transparency Platform

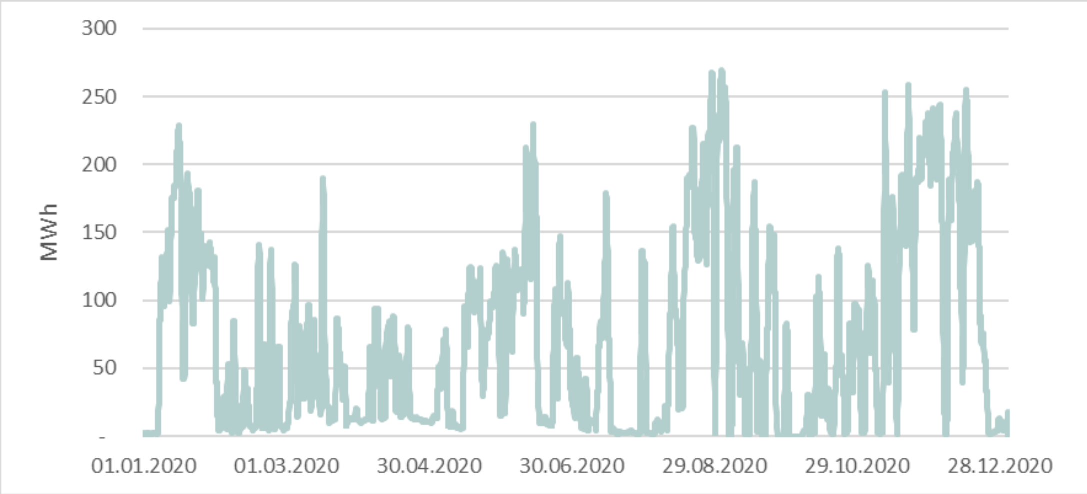

Figure 37 - Hydro reservoir power generation (daily average) in 2020 in Serbia[83]

Storage

Serbia has two hydroelectric sources of storage:

- ✓ From its reservoirs: 472 MW of generation capacity and 500 GWh[84] of storage capacity.
- ✓ From its pump hydro storage: 639 MW of generation capacity and 194 GWh[85] of storage capacity.

Monthly generation of PHS in Serbia is shown in Figure 38[86]. Monthly generation volumes range from 35 to over 80 GWh, representing between 55 to over 130 hours of generation at maximum capacity per month, as well as between 3.5 to 8 full charge-discharge cycles per month.

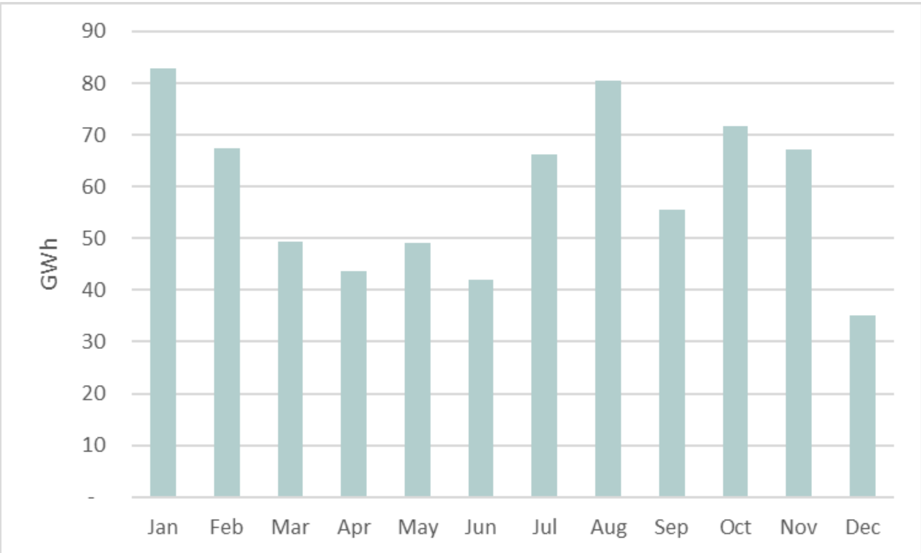

Figure 38 - Monthly generation (GWh) from PHS in Serbia in 2020

[83] ENTSO-E Transparency Platform
[84] PE EPS
[85] PE EPS
[86] ENTSO-E Transparency Platform

Cross-border interconnections

Installed capacities

Serbia is interconnected with 4 CPs and 4 EU MSs(Croatia, Bosnia and Herzegovina, Bulgaria, Hungary, Kosovo*, Montenegro, North Macedonia and Romania) for a total import NTC of 3 825 MW and export NTC of 4 025 MW, as described in Table 29.

Table 29 - Indicative (maximum) NTC values at Serbians borders[87]

Borders	Import (MW)	Export (MW)
Serbia - Bulgaria	350	300
Serbia - Croatia	600	600
Serbia - BiH	600	600
Serbia - Hungary	700	800
Serbia - Kosovo*	325	325
Serbia - Montenegro	200	300
Serbia - N. Macedonia	250	300
Serbia - Romania	800	800
TOTAL	3 825	4 025

Cross-border flows

Monthly cross-border flows are depicted Figure 39 for year 2020. Serbia shows higher cross-border flows in the export direction (6 TWh) than in the import one (5.3 TWh). Half of exports flows are directed to North Macedonia. In the import direction, two interconnectors see significant flows: from Bosnia and Herzegovina and Montenegro, with respectively 1 TWh and 1.1 TWh.

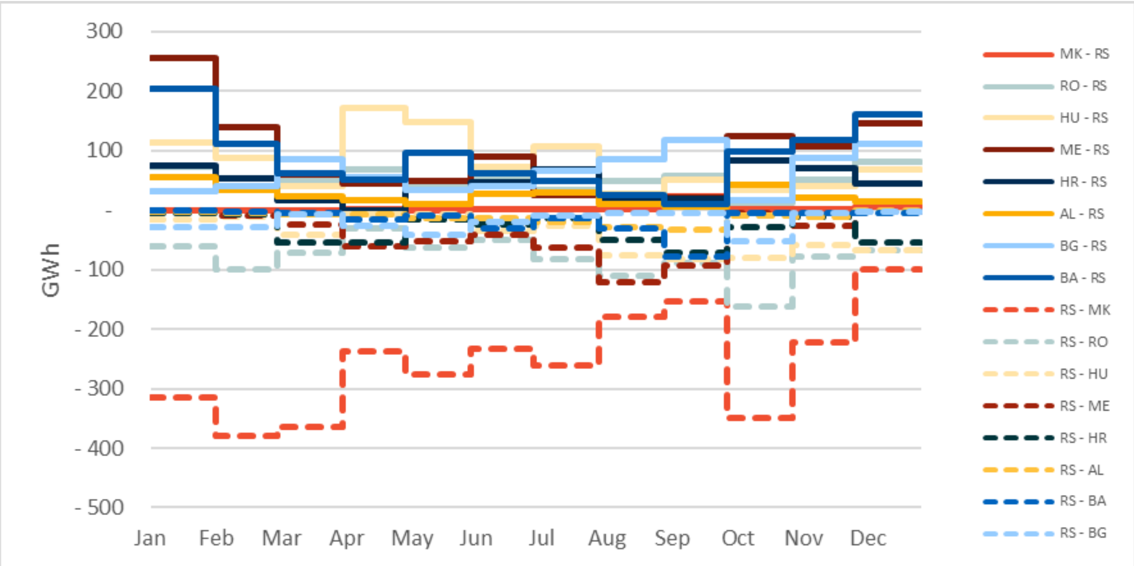

Figure 39 - Cross-border physical flows in Serbia (GWh) in 2020[88]. Exports are depicted as positive values, and imports as negative values.

[87] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties
[88] ENTSO-E Transparency Platform

Congestion hours[89]

Estimated average use of interconnection and share of congestions hours are presented in Table 30 for year 2020. Coherently with what has been presented in the previous subsection, the interconnection between Serbia and North Macedonia (RS>MK) is characterized by a high use and congestions. As NTC capacities are quite high, this is the only line showing uses above 50% of the capacity.

Table 30 - Interconnections use and congested times in Serbia in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
MK-RS	1%	0%
RS-MK	83%	63%
RO-RS	9%	0%
RS-RO	14%	0%
HU-RS	16%	0%
RS-HU	7%	0%
ME-RS	43%	26%
RS-ME	18%	4%
HR-RS	10%	0%
RS-HR	7%	0%
XK-RS	15%	4%
RS-XK	10%	4%
BA-RS	20%	0%
RS-BA	4%	0%
BG-RS	25%	2%
RS-BG	9%	0%

Residual capacities by 2030 and 2040

According to the *A carbon pricing design for the Energy Community* study[90]:

- 300 MW of lignite capacity are expected to be decommissioned in 2023. A little more than 4 GW can be considered still in operation for the 2030 and 2040 horizons.
- Regarding fossil gas power plants, 135 MW will reach end of life by 2026 and the remaining 120 MW by 2032.

[89] See footnote 8

[90] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community

2.9 Ukraine

Summary of existing flexibilities

Table 31 - Summary of existing flexibilities in Ukraine

<table>
<tr><th rowspan="2">Ukraine (UA)</th><th>Current</th><th colspan="2">Residual</th></tr>
<tr><th>2021</th><th>2030</th><th>2040</th></tr>
<tr><td rowspan="2">Flexible power generation</td><td colspan="3">4 637 MW of hydroelectric reservoir capacity
13 835 MW of nuclear capacity</td></tr>
<tr><td>19 125 MW of coal capacity
6 104 MW of CHP (NG and fuel oil) capacity</td><td>4 820 MW of coal capacity
3 400 MW of CHP (NG) capacity</td><td>1 979 MW of coal capacity
1 900 MW of CHP (NG) capacity</td></tr>
<tr><td>Storage</td><td colspan="3">4 637 MW of power capacity and 890 GWh of storage capacity of hydroelectric reservoir
1 834 MW of power capacity and 13.8 GWh of storage capacity of PHS</td></tr>
<tr><td>Interconnections[91]</td><td colspan="3">1 900 MW for import (with the CESA)
2 035 MW for export (with the CESA)</td></tr>
</table>

Flexible power generation

In 2020, Ukraine's electricity production mix is dominated by nuclear (around 55% of production), followed by coal (around 25%) as can be seen in Figure 40.

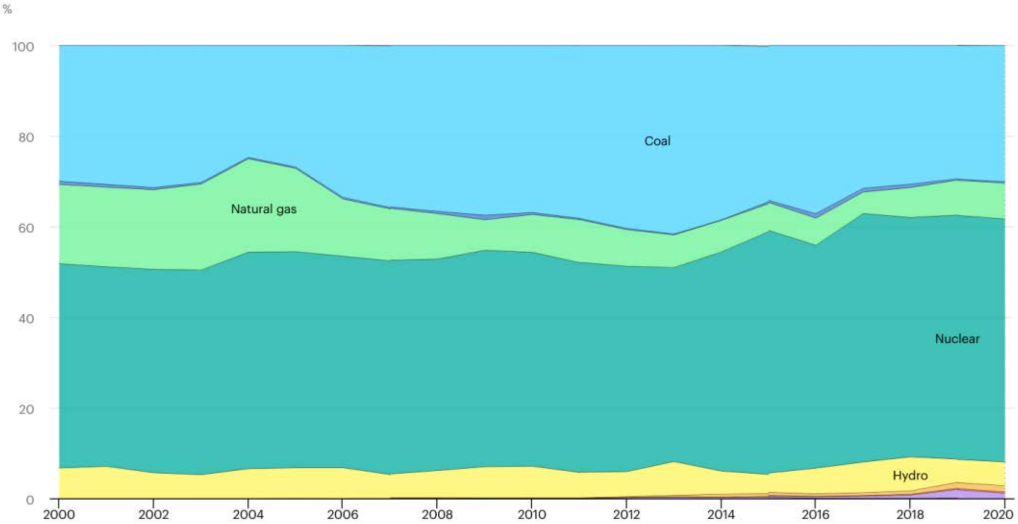

Figure 40 - Electricity generation by source in Ukraine[92]

The 2021 installed capacities are summarized in Table 32.

[91] Projections by 2030/2040 corresponding to existing values, without consideration of additional interconnection or improvements in NTCs.
[92] https://www.iea.org/countries/ukraine

Table 32 - Installed capacities (MW) per technology in Ukraine, 2021[93]

Technology	Installed capacities (MW)
Coal	21 842
CHP[94]	6 104
Nuclear	13 835
Hydro Run-of-river	192
Hydro Reservoir	4 637
Hydro Pumped Storage	1 834
Biomass	254
Wind onshore	1 529
PV	6 365

Only hydro reservoirs profiles were provided for the purpose of the study. Monthly generation are depicted in Figure 41 for years 2017-2021. The generation is quite consistent all over the year, with a higher share during the months of March to June on several years. The average capacity factor is quite low (19%).

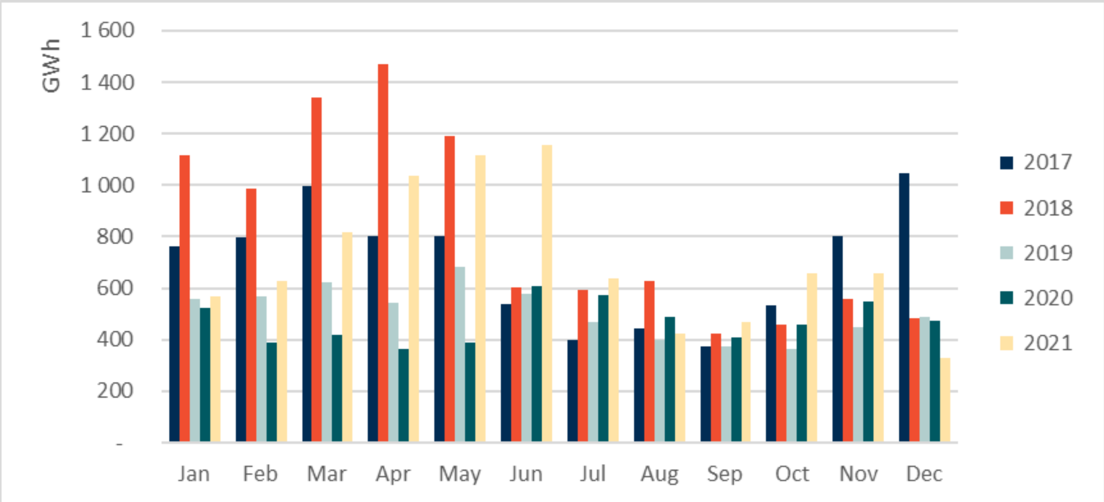

Figure 41 - Monthly hydro reservoirs generation (GWh) over the years 2017-2021[95]

Storage

There are two sources of existing storage capacities:

- ✓ Hydro reservoirs: it concerns 7 lakes (Dnister, Kremenchuk, Kamianske, Kakhovka, Kyiv, Kaniv and Dnieper) for a total capacity of 4 637 MW and 890 GWh of hydroelectric reservoir storage.
- ✓ Pump Hydro storages: there are three pumped hydro storage plants (Kyivska, Dnistrovska and Tashlytska) for a total capacity of 1 834 MW and a total storage capacity of 13.8 GWh, of which only 9.4 GWh are available for operations.

Cross-border interconnections

In 2020, most of Ukraine's power system was interconnected with the Russian power system (UPS/IPS), and a small portion in the west of the country (Burshtyn Island) was interconnected with the European system (CESA). Since March 2022, Ukraine's power system is fully synchronized with CESA. Thus, only

[93] Ukrenergo, https://ua.energy/installed-capacity-of-the-ips-of-ukraine/
[94] Combined heat and power plants, consisiting on plants that can operate on gas or fuel-oil. Their operation is highly seasonal and flexibility is limited due to the operation linked to heat generation.
[95] Ukrenergo

cross-border interconnections with the CESA will be presented in this section. For interactions with Moldova, please refer to section 2.5.

Installed capacities

Ukraine is interconnected with four EU MSs from the CESA (Hungary, Poland, Romania and Slovakia) for a total import NTC of 1 900 MW and export NTC of 2 035 MW, as described in Table 33.

Table 33 - Indicative (maximum) NTC values at Ukraine borders[96]

Borders	Import (MW)	Export (MW)
Ukraine - Hungary	900	800
Ukraine - Poland	-	235
Ukraine - Romania	400	400
Ukraine - Slovakia	600	600
TOTAL	1 900	2 035

Cross-border flows

Monthly cross-border flows are depicted Figure 42. They are only available from January to September on the ENTSO-E Transparency Platform for year 2020, making the analysis partial. During this period, Ukraine shows higher cross-border flows in the export's direction (4.1 TWh) than in the import's one (2.6 TWh). The export's flows are the most significant with Romania, representing half of them. Cross-border flows towards Poland and Hungary share the remaining half while the one going to Slovakia are almost null. On the other hand, in the import's direction, almost all flows come from Slovakia. In overall, the exchanges are more significant in the winter period than the summer one.

[96] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties

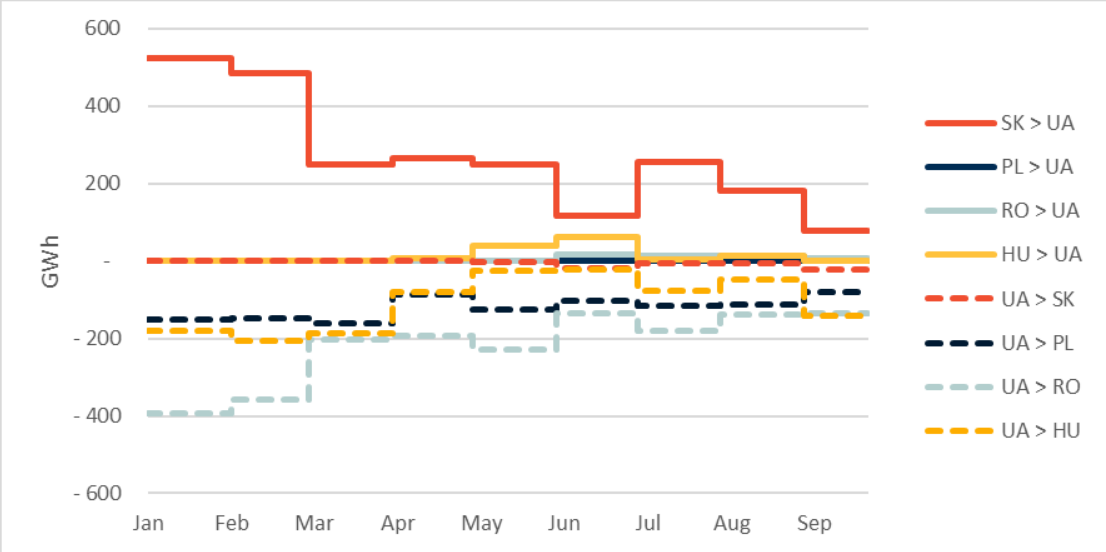

Figure 42 - Cross-border physical flows in Ukraine (GWh) in 2020[97]. Exports are depicted as positive values, and imports as negative values.

Congestion hours[98]

Estimated average use of interconnection and share of congestions hours are presented in Table 34 for year 2020. Three interconnections show high estimated use: UA>PL, UA>RO and SK>UA. Estimated shares of congested times remain low for all interconnections.

Table 34 - Interconnections use and congested times in Ukraine in 2020

Interconnection	Estimated average use of interconnection	Estimated share of congested times
MD-UA	0%	0%
UA-MD	7%	0%
SK-UA	57%	21%
UA-SK	1%	0%
PL-UA	NA	NA
UA-PL	72%	0%
RO-UA	2%	0%
UA-RO	66%	32%
HU-UA	2%	0%
UA-HU	19%	0%

[97] ENTSO-E Transparency Platform
[98] See footnote 8

Residual capacities by 2030 and 2040

Different sources were crossed to understand the evolution of residual capacities:

- ✓ According to the views of UA's stakeholders, a rapid coal phase-out is likely to materialise, with only 4.9 GW of coal power plants remaining already by 2030, and only 2 GW by 2040, in line with the announcement by the Ukrainian government during COP26 to phase-out coal by 2035.[99]
- ✓ According to the *A carbon pricing design for the Energy Community* study[100], CHP power plants expected decommissioning would lead to 3.4 GW remaining by 2030 and 1.9 GW by 2040.
- ✓ All nuclear capacities remain available up to 2040. Additional nuclear capacities are foreseen by UA's stakeholders[101].

[99] National plans may change due to the Ukraine conflict.
[100] Kantor, E3M, January 2021, A carbon pricing design for the Energy Community
[101] Ukrenergo

3 Introduction of scenarios

This chapter presents an overview of the main parameters that define the prospective scenarios to assess the flexibility needs in the CPs at the 2030 and 2040-time horizons. First, it introduces the three main generation capacity and two interconnection capacity scenarios, followed by a detailed outline of the specific assumptions per country.

3.1 Scenario philosophy

This study is based on three main prospective scenarios that feature different levels of renewables penetration and decarbonization of the power generation sectors of the Contracting Parties by 2030 and 2040. The design of the scenarios is strongly based on the Energy Community-Carbon Pricing study (EnC-CP)[102], and integrates additional assumptions based on feedback and validation from relevant stakeholders from the CPs and from the EnC Secretariat. The three generation capacity scenarios are the following, each one defined for the 2030 and 2040 horizons:

- Baseline, reflecting a *business-as-usual* development, with relatively slow uptake of renewable energy sources (RES). It is based on the Baseline scenario of the EnC-Carbon Pricing study.
- Moderate, an intermediate scenario between Baseline and Ambitious. Installed generation capacities for each technology are defined as the mean value between Baseline and Ambitious.
- Ambitious, a scenario of strong decarbonization of the power generation sector with a high uptake of RES and almost complete phase-out of lignite and coal-based power generation. This scenario is primarily based on the Gradual Carbon Pricing strategy and Market integration scenario (GradualCP-MInt) from the EnC-Carbon Pricing study.

Each scenario defines specific installed power generation capacities for each CP. Additional parameters, such as the total energy demand per country are also defined per scenario.[103]

The three scenarios of vRES capacities allow to determine the flexibility needs for the EnC power system, for the 2030 and 2040 horizons. The flexibility needs are calculated at the CP level, and they capture the dynamics of the hourly residual load (calculated as the hourly demand less the hourly generation from variable RES), on daily, weekly and seasonal timescales.

Then, optimal flexibility portfolios are determined for two scenarios with diverging cross-border interconnection capacities, here called Fragmented market and Integrated market (MI) (see details in Section 5). These scenarios are used to assess the value of market integration and regional cooperation among CPs and with the EU[104].

A total of 10 model runs were analysed, as shown in Table 35.

[102] A carbon pricing design for the Energy Community - Kantor, E3-M (January 2021)
[103] A CP's national final electricity demand may vary across scenarios.
[104] For Georgia, only the Fragmented market scenario was considered.

Table 35 - Analysed scenarios

Scenario name	RES capacity deployment	Year	Market integration
Baseline 2030	Baseline	2030	Fragmented
Baseline 2040	Baseline	2040	Fragmented
Moderate 2030	Moderate	2030	Fragmented
Moderate 2030 - MI	Moderate	2030	Integrated
Moderate 2040	Moderate	2040	Fragmented
Moderate 2040 - MI	Moderate	2040	Integrated
Ambitious 2030	Ambitious	2030	Fragmented
Ambitious 2030 - MI	Ambitious	2030	Integrated
Ambitious 2040	Ambitious	2040	Fragmented
Ambitious 2040 - MI	Ambitious	2040	Integrated

3.2 Overview of scenario assumptions across CPs

This study analyses a wide range of scenarios for the power generation sectors of the Contracting Parties, which consider recent relevant studies as well as national forecasts and policies on RES uptake and coal phase-out, when available. The total installed capacity per scenario, aggregated for the 9 CPs is shown in Figure 43 (detailed data per country can be found in Annex B).

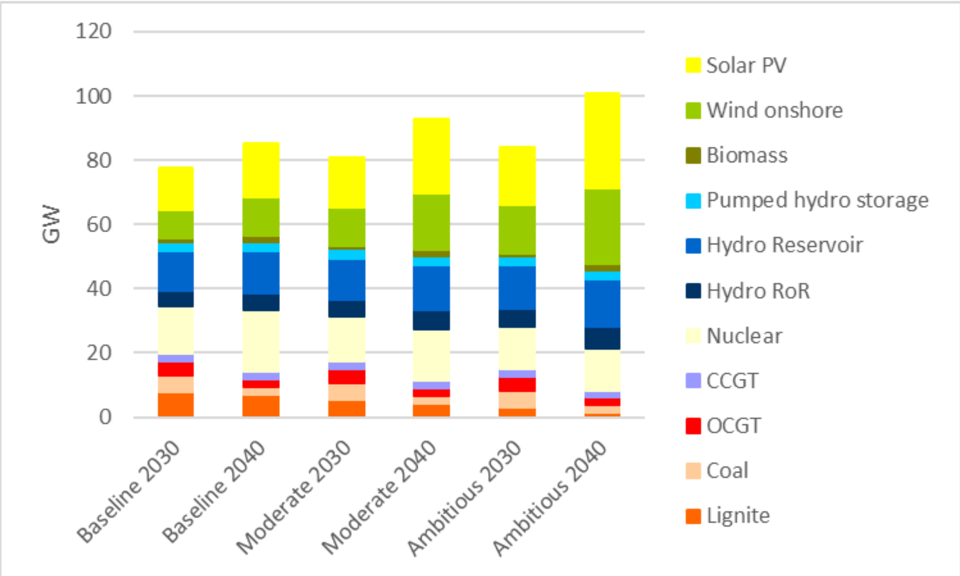

Figure 43 - Aggregated installed capacities among EnC CPs (prior to optimization[105] to determine optimal flexibility portfolios).

The vRES share of the installed capacity ranges from 28% in Baseline 2030 to 53% in Ambitious 2040, aggregated for all CPs, albeit significant differences exist among CPs, as shown in Figure 44. On one hand, Kosovo* foresees the highest share of vRES capacity in their generation mix, reaching almost 80% in the Ambitious 2040 scenario. On the other hand, Georgia has the lowest share of vRES but benefits of a generation mix largely composed by hydro power plants, as does Albania.

[105] OCGT, CCGT and additional PHS capacities are the only power generation capacities subject to capacity expansion optimisation. The values depicted in the graph reflect current capacities still existing in 2030/40.

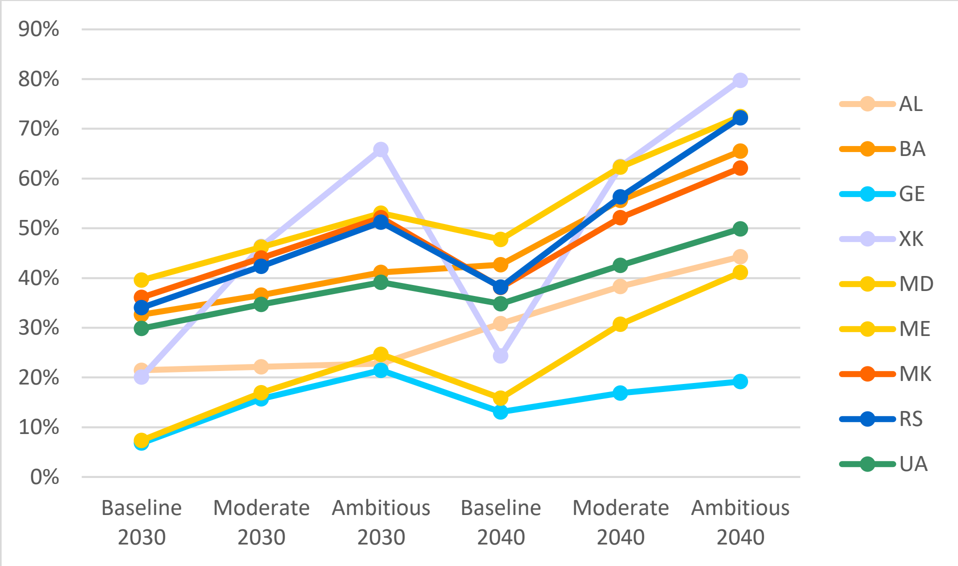

Figure 44 - Share of variable RES (wind and Solar PV) in total installed capacity (before optimization) per country and scenario.

Regarding existing flexibility assets, Figure 45. shows the residual flexibility assets in the Baseline 2030 scenario[106]. Flexibility assets are dominated by reservoir hydro power plants in Ukraine, Georgia, Albania, and Bosnia and Herzegovina. Serbia, Montenegro and North Macedonia have lower flexible capacities, mainly hydro and PHS. Only in Ukraine and Moldova[107] there exists significant gas-fired flexibility assets.

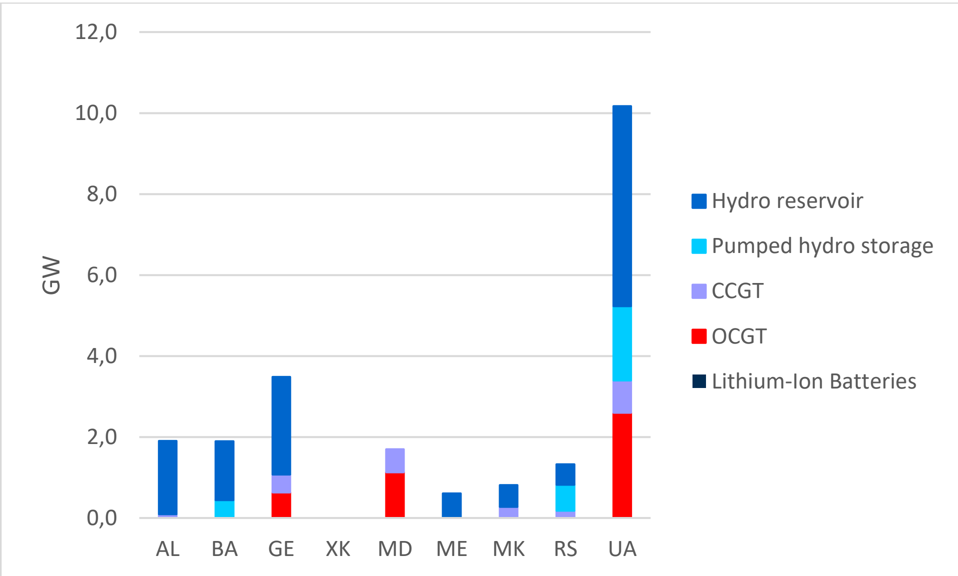

Figure 45 - Remaining flexibility assets in scenario Baseline 2030

The total demand across CPs is shown in Figure 46. The ambitious scenario has higher demand projections, reflecting the feedback from national stakeholders (notably TSOs) on load growth.

[106] Baseline 2030 is representative of the flexibility assets for the rest of the scenarios. Main differences between scenarios arise from hydro reservoir developments in GE, as well as a phase out of part of the OCGT installed capacities in UA.[106]
[107] However, Moldova's capacities are ageing and present low efficiency.

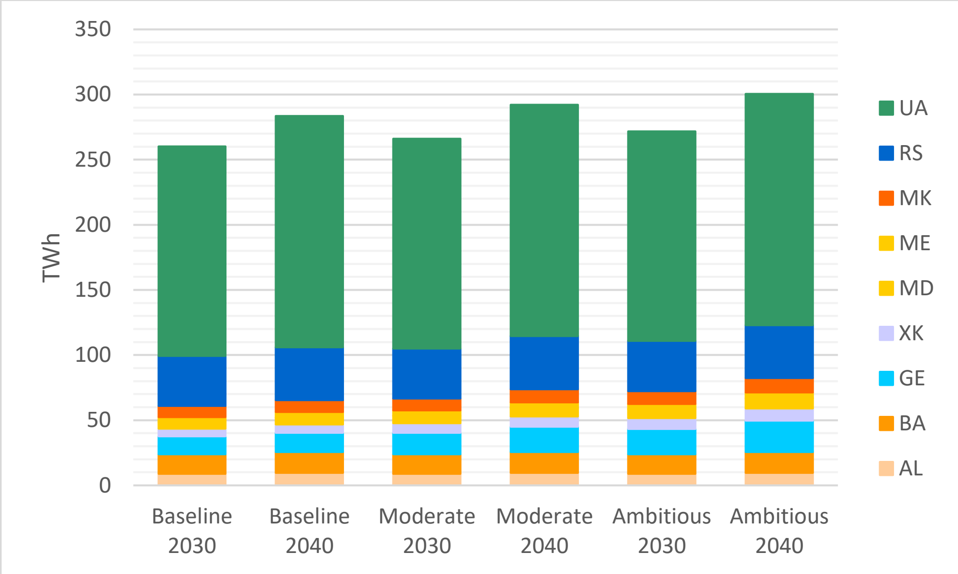

Figure 46 - Total demand, including transmission and distribution losses, per CP and scenario.

3.3 Country specific hypotheses

For some scenarios the assumptions from the EnC-CP study were adapted in coordination with relevant stakeholders to reflect national projections, in particular to define more ambitious renewable targets for the Ambitious scenario. This is summarized in Table 36, where the main source of data is outlined (EnC-CP Baseline/GradualCP-MInt refer to the respective scenarios in the EnC-Carbon Pricing study, and 'Data from CP' refers to feedback from national stakeholders).

Table 36 - Overview of sources for RES deployment by scenario and CP

Contracting Party	Baseline	Ambitious
Albania	EnC-CP Baseline	EnC-GradualCP-MInt
Bosnia & Herzegovina	EnC-CP Baseline	EnC-GradualCP-MInt
Georgia	EnC-CP Baseline	Data from CP
Kosovo*	EnC-CP Baseline	Data from CP
Moldova	EnC-CP Baseline	Data from CP
Montenegro	EnC-CP Baseline	EnC-GradualCP-MInt
North Macedonia	EnC-CP Baseline	Data from CP + EnC-GradualCP-MInt
Serbia	EnC-CP Baseline	EnC-GradualCP-MInt
Ukraine	Data from CP	Data from CP + EnC-GradualCP-MInt

The main changes applied to the EnC-CP scenarios are listed below.

Georgia

The projections of the national stakeholders[108] were used for the Ambitious scenario. They consider a significant development of the power sector as whole. In particular, the Ambitious scenario sees a strong increase of hydro capacities (+30% increase from 2022 to 2040 in Baseline, versus +116% from 2022 to 2040 in Ambitious) and demand growth (+66% of total demand in Ambitious compared to the Baseline scenario). CP projections used in the Ambitious scenario also consider stronger RES penetration.

[108] GSE, Georgian TSO

Kosovo*

A strong decarbonization scenario provided by the stakeholders[109] was considered for the ambitious scenario. It considers a partial lignite phase-out, not seen in the Baseline, reducing the lignite capacities from 1288 MW currently installed, to 540 MW by 2030 and 2040. This is accompanied by a strong uptake of RES, rising to 2.8 GW of wind and PV by 2040 versus only 0.4 GW in the Baseline scenario, as well as a higher demand growth (+52% of total demand in Ambitious versus Baseline scenario).

Kosovo* has only one small hydro reservoir (Ujmani Dam, 32 MW), whose operation follows the needs of water supply, agricultural needs and others. In this study this power plant was modelled as a run-of-river hydro power plant using historical data.

Moldova

The forecasts of the CP were adopted for the Ambitious scenario, which show more ambitious targets for RES penetration, as well as a higher demand growth (+55% of total demand in Ambitious versus Baseline scenario).

North Macedonia

The Ambitious scenario considers a lignite phase-out by 2030, and the development of new hydro projects (total hydro installed capacities increasing by 47% in Ambitious 2040 compared to the Baseline 2040), according to the CP's projections. This is accompanied with an increase in demand of 20% by 2030 and 28% by 2040 in the Ambitious scenario with respect to the Baseline one.

Ukraine

The Baseline scenario for Ukraine, derived from CP's projections, is characterized by a development of additional nuclear power plant capacities (from 13.8 GW of existing capacities in 2022 to 19.2 GW by 2040) and a slow growth of renewable capacities (2022 wind-onshore and solar PV capacities amount to 8.4 GW, rising to 17 GW by 2040). On the other hand, the Ambitious scenario maintains current nuclear capacities but with a higher penetration of RES (25.5 GW of wind and PV by 2040). A significant reduction on coal capacities is foreseen for all scenarios, passing from 18.5 GW in 2022 to 4.8 GW in 2030 and only 2.0 GW in 2040, as well as CHP capacities, passing from 6.4 GW in 2021 to only 1.9 GW in 2040. The remaining CHP capacities were considered as gas-fired turbines in the capacity optimization of flexibility assets.

[109] Department of Energy, Ministry of Economy, Kosovo*

4 Quantification of flexibility needs

This section introduces the notion of flexibility needs for the three different timescales (daily, weekly and annual) and present their evolution with scenarios in the Energy Community. The reader must note that intra-hourly flexibility needs are not considered in this study.

4.1 Methodology

The French transmission system operator RTE has introduced a number of metrics that permit to evaluate national flexibility needs[110]. These metrics are calculated on the basis of the residual load[111] and facilitate the understanding of the extent to which rising RES shares increase these needs. Responding to these needs would lead to a fully smoothened net load that could be fully satisfied by baseload capacities. A large number of technical solutions exist to respond to flexibility needs at different time scales. Hence, flexibility needs are likewise distinguished regarding the time horizon. We distinguish daily, weekly and annual flexibility needs.

Daily flexibility needs are defined as the difference between the hourly residual load throughout a day and its daily average (cf. the shaded areas in the upper part of Figure 47). The result is expressed as a volume of energy per day (e.g. GWh/day). Summing up these daily (positive) differences over all 365 days of the year reveals the overall daily flexibility needs (expressed in GWh or TWh per year) one may respond to in order to obtain a residual load that is flattened out on a daily basis.

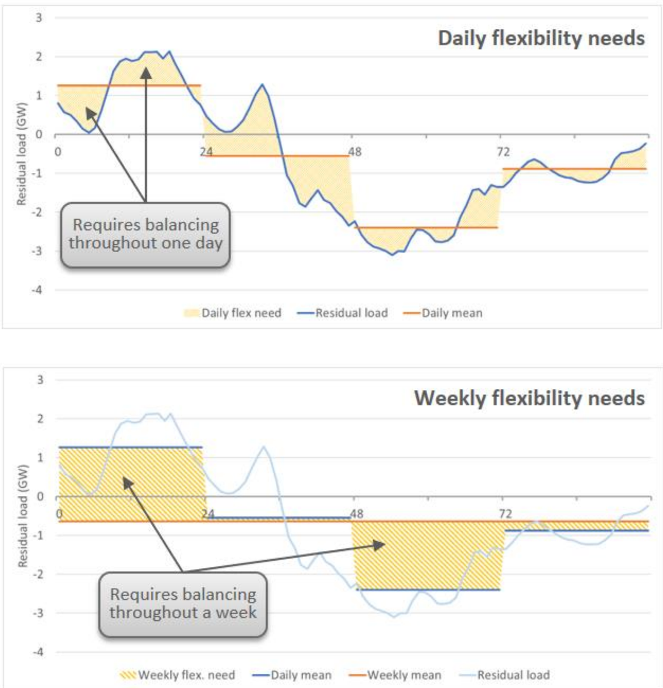

Figure 47 - Illustration of daily and weekly flexibility needs for a 4-day excerpt, based on the vRES production period in Denmark

A similar calculation is realised in order to obtain the weekly flexibility needs, comparing the daily averages of the residual load (i.e. the residual load after having replied to all daily flexibility needs) with the mean residual load across each week (cf. lower part of Figure 47). Summing up the weekly flexibility needs of all 52 weeks gives the overall weekly flexibility needs.

[110] Besoins de flexibilité liés au développement des EnR, RTE, 2017

[111] The residual load is calculated as the total hourly system load less the production from variable renewable energy sources.

Last, annual flexibility needs are determined as the cumulated difference between the weekly averages and the mean residual load across the entire year (not illustrated).

4.2 Flexibility needs

4.2.1 Daily flexibility needs

Daily flexibility needs are notably driven by an increasing level of solar power generation and by day/night consumption patterns. They decrease up to a certain share of PV generation (as PV generation compensates for the higher consumption level in day-time hours) and then increase due to the offset it creates with peak demand (what is known as the *duck curve*). The PV shares in all CPs and scenarios seem to exceed this inversion point. Thus, daily flexibility needs increase with solar deployment. The values vary depending on horizon and vRES deployment scenario, from 0.5 TWh up to 2 TWh for almost all CPs, except Serbia and Ukraine. In the case of Serbia, daily flexibility needs go from 3 TWh to 5 TWh. The volume and variation are larger in the case of Ukraine, from 8 TWh to 12.5 TWh.

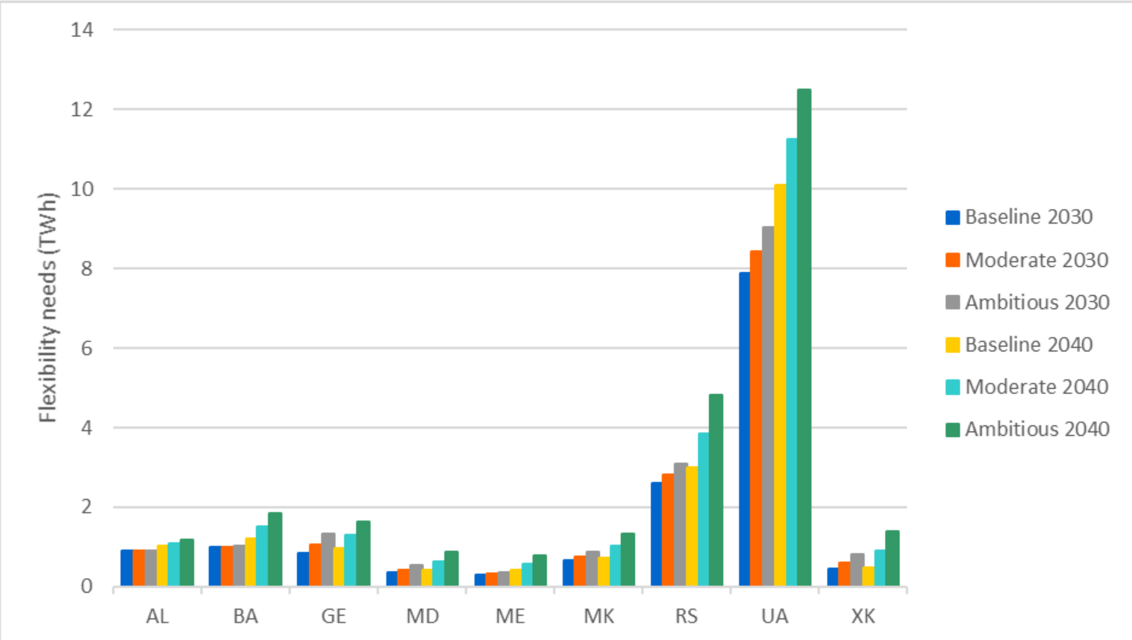

Figure 48 - Daily flexibility needs

4.2.2 Weekly flexibility needs

Weekly flexibility needs depend typically on the penetration level of wind power generation and the imbalance in workweek-weekend consumption patterns. They increase with wind deployment in the different scenarios. Depending on the scenario, the values vary with horizon and vRES deployment but are lower in general than daily flexibility needs, below 1.5 TWh for most CPs except for Ukraine (from 3 TWh to 6 TWh).

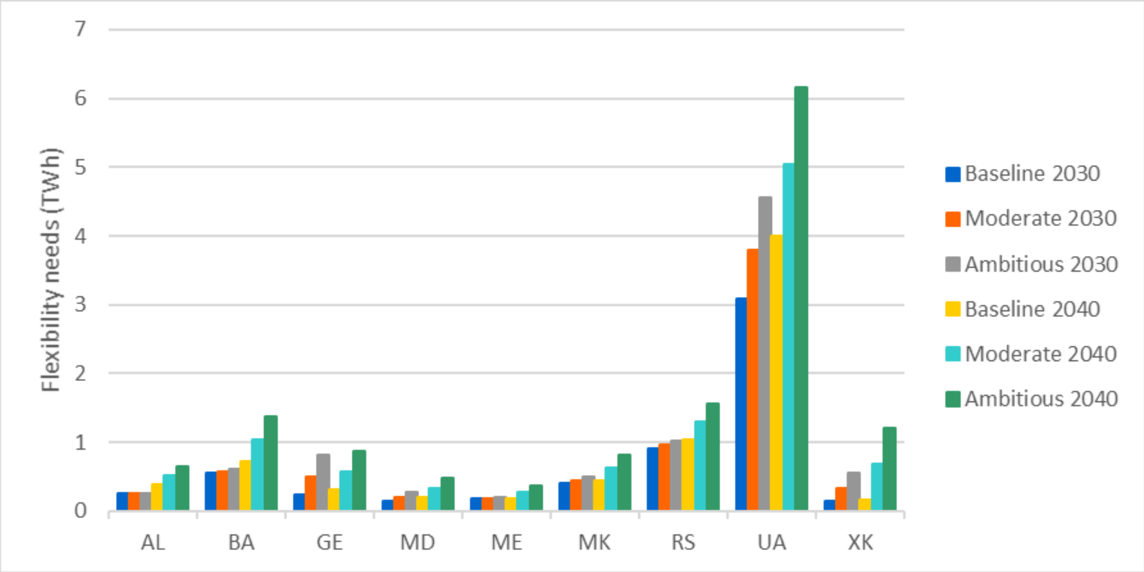

Figure 49 - Weekly flexibility needs

4.2.3 Annual flexibility needs

Finally, annual flexibility needs evolve with seasonal wind, solar and consumption patterns. They can increase with solar generation and decrease with wind generation, as the seasonal pattern of wind correlates with power consumption (higher in winter, lower in summer). In the case of Ukraine for instance, annual flexibility needs decrease across scenarios, as wind deployment is more significant than solar. This phenomenon is not observed in the other CPs. The annual needs are low (below 0.5 TWh) comparatively to daily and weekly needs, except for Georgia, Kosovo*, Serbia and Ukraine.

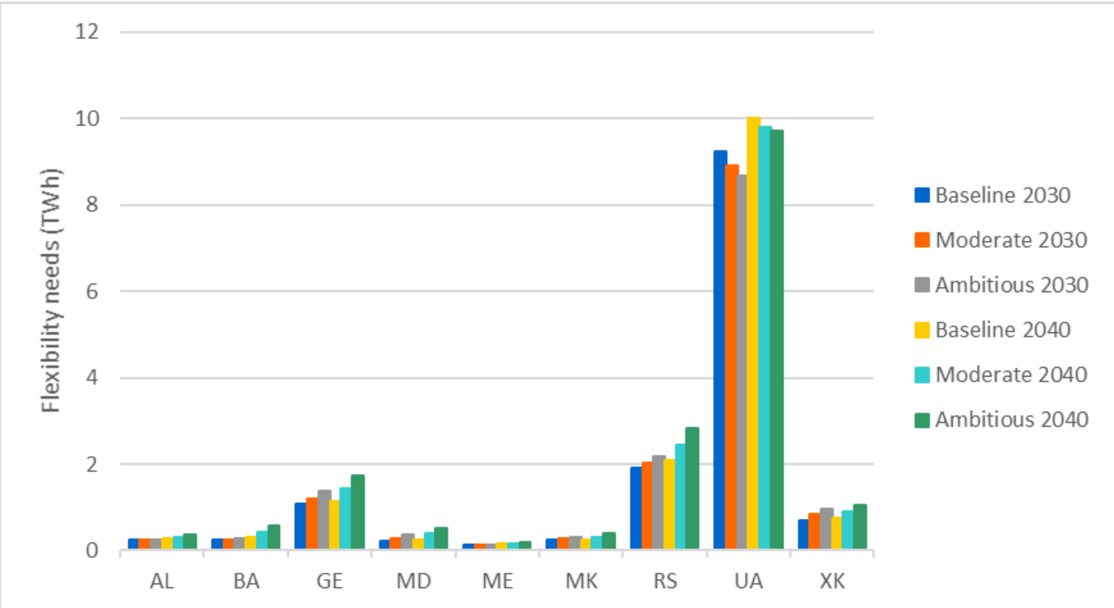

Figure 50 - Annual flexibility needs

5 Cost-optimal flexibility portfolios: modelling methodology and hypotheses

This chapter will introduce the overall modelling approach, outline the macro-economic assumptions which equally apply to all scenarios as well as the more specific assumptions which may differ between scenarios.

5.1 The overall modelling approach

5.1.1 The European energy system model Artelys Crystal Super Grid

Artelys Crystal Super Grid is a software solution, developed and distributed by Artelys, dedicated to the modelling of energy systems[112], from the regional scope to intercontinental contexts. This tool is highly configurable, allowing its users to easily develop customised scenarios and parameterisations, run simulations as well as establish large-scale capacity expansion plans required to conduct quantitative assessments such as cost-benefit analyses.

This solution has been adopted by, amongst others, the French Regulatory Commission of Energy (CRE), the Belgian Energy Ministry (FPS Economy), the Belgian Federal Planning Bureau (FPB), power producers, academics and researchers, the European Commission[113], the Joint Research Centre (JRC) of the European Commission, private partners in large-scale R&D projects, etc.

The key features of Artelys Crystal Super Grid are:

- ✓ Optimal dispatch – Artelys Crystal Super Grid optimises the generation of each energy asset for each timestep represented in the simulation in order to minimise the total costs of the energy systems, while taking account interlinkages between area modelled (e.g. with interconnections asset) and between timesteps (e.g. with storage assets).
- ✓ Bottom-up model – All power generation assets can be represented at unit or country level along with demand-response capacities and storage technologies. Interconnection capacities between countries or regions are explicitly represented.
- ✓ Time resolution – The timestep is customisable in Artelys Crystal Super Grid. For power system modelling, an hourly time resolution is generally adopted in order to study topics such as the integration of renewable energy sources, resource adequacy etc. The overall duration of the simulation is generally one year, i.e. 8760 hourly time steps for power system simulations.
- ✓ Geographical resolution – The geographical resolution is customisable in Artelys Crystal Super Grid, from the representation of regions to aggregation of countries.
- ✓ Climatic years and stress cases – Artelys Crystal Super Grid is able to assess different stress-cases by considering multiple climatic years.

In this study, the model is computed at an hourly resolution and the Contracting Parties are represented at a national level (as a single yet interconnected node). One average climatic year (2007) was simulated.

[112] Artelys Crystal Super Grid allows for multi-energy system modelling, including power, gas and hydrogen infrastructures. In this study, only the power system was modelled.
[113] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/metis_en

Using the Artelys Crystal Super Grid tool, the operation of assets is jointly optimized with the capacity expansion of flexibility solutions, including the optimized operation of hydro reservoirs and pumped hydro storages, existing thermal fleets, smart electric vehicles and the use of interconnections. Only the following flexibility assets were considered for capacity expansion[114]:

- CCGT and OCGT (gas-fired) plants
- Lithium-ion batteries
- Pumped hydro storage (considering a limited potential)

Due to the country level aggregation, it only takes into account cross-border interconnection constraints. The contributions of the different flexibility solutions to meet flexibility needs were assessed at a daily, weekly and annual/seasonal timescale. Flexibility required at the sub-hourly timescale (reserves, inertia), adequacy issues (considering extreme events and various weather years), or coming from internal grid constraints (congestions) were not included in the scope of this study.

5.1.2 Modelling of Ukraine, Moldova and WB6

The Ukraine-Moldova power system (IPS) was expected to be synchronized with the Continental European Synchronous Area (CESA) by 2023[115], effectively disconnecting themselves from the interconnected Russian power system (UPS/IPS). The process of synchronization with CESA was moved forward due to the war in Ukraine, entering into effect in March 2022.[116]

Therefore, this study did not to consider any transport capacities between Ukraine and the UPS/IPS countries (Russia, Belarus) for both 2030 and 2040 horizons, and assumed a full integration of Ukraine and Moldova in the pan-European ENTSO-E power system. This implies that, similar to the Western Balkan CPs, Ukraine and Moldova were jointly modelled with the EU power system. Thus, the Pan-European power system ranging from Spain to Ukraine, and from Italy to Finland, was modelled jointly in the *Artelys Crystal Super Grid* tool, as shown in Figure 51.

Given that the modelling of the flexibility options involves the simulation of the European power market (in order to properly reflect cross-border flows), a scenario has to be chosen for the EU Member States (plus Norway, Switzerland and the UK) too. In order to ensure a maximum coherence between the scenarios of CPs and the assumptions for EU Member States, we rely on the Distributed Energy (TYNDP-DE) scenario of the TYNDP 2020. The TYNDP-DE scenario represents a pathway to achieve carbon neutrality in the EU by 2050, driven by a strong uptake of RES, therefore aligned with the strong RES objectives of the Ambitious scenario of this study in particular.

[114] Other assets such as coal, nuclear or vRES power plants have their capacities fixed in each scenario.
[115] https://ua.energy/european-integration/integration-entso-e/
[116] It is important to note that the present analysis does not take into account the consequences related to the invasion of Russia in Ukraine since 24 February 2022. Nonetheless, the assessments carried out for the years 2030 and 2040 consider a full synchronisation of Ukraine and Moldova with the Continental European Synchronous Area (CESA).

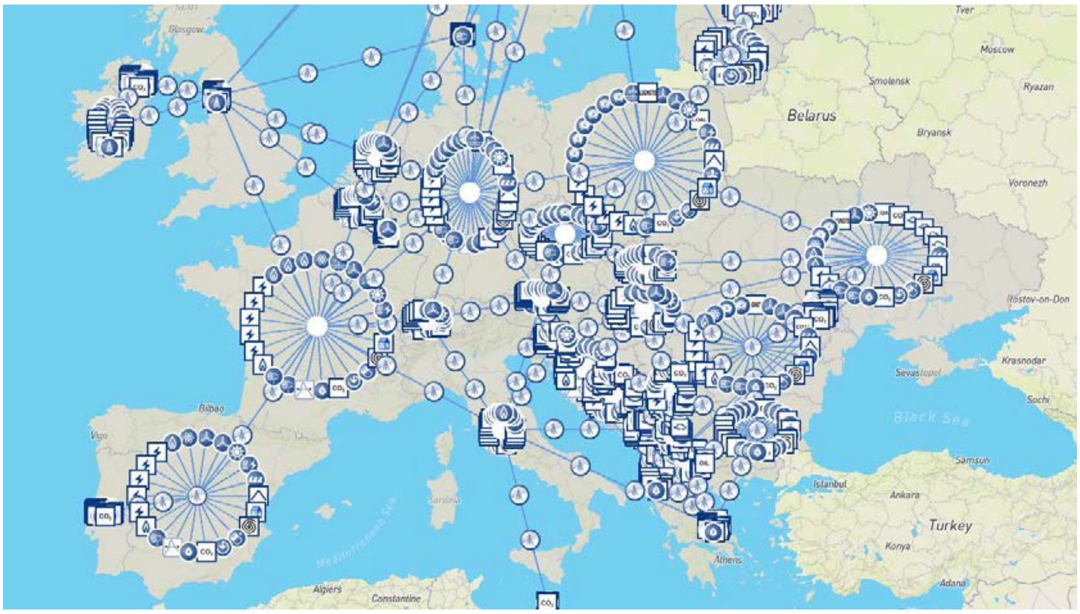

Figure 51 - Screenshot of the modelling of the Pan-European power system in the simulation tool.

5.1.3 Modelling of Georgia

Georgia's power system was modelled in the *Artelys Crystal Super Grid* tool as an island with simplified interconnection exchanges with neighbouring countries, optimizing the operation and investments of assets located within Georgia only, as shown in Figure 52.

Figure 52 - Screenshot of the modelling of Georgia in Artelys Crystal Super Grid tool.

Historical exchanges with neighbouring countries show a seasonal behaviour of import/export (see Section 2.3), with high exports occurring in summer months and imports during autumn-winter months.

Interconnection exchanges with neighbouring countries are modelled through two constraints: hourly exchanges are limited by NTC capacities (2310 MW[117] , which considers only interconnections with Turkey

[117] Only one interconnection scenario is considered for Georgia

and Azerbaijan, reflecting the operational constraints of the Georgian power system[118]), and the monthly distribution of exchange volumes follow the monthly distribution of historical flows, to capture the seasonality of imports/exports of the country. Yearly import and export volumes have been determined based on the need of the Georgian power system for additional supply or ability to export RES electricity that would otherwise be curtailed. The net balance of imports and exports therefore depends on the individual scenarios. This modelling approach assumes already an improvement in market integration of Georgia with its neighbouring countries, as current exchanges are carried out by bilateral exchanges, with fixed set points for an interconnector for potentially several days[119].

5.2 Techno-economic assumptions

5.2.1 *Energy carrier prices*

This study uses the forecasts of energy carrier prices of the EnC-Carbon Pricing study, outlined in Table 37[120]. They consider local prices for lignite (for each country in WB6), as well as slightly lower prices for gas in Ukraine and Moldova than the rest of Europe[121]. Prices from the TYNDP-2020 were used to fill missing gaps in energy carrier prices (lignite and coal) for the EU+ countries.

Table 37 -Energy carrier prices by year and country

Price	WB6		UA/MD		GE		EU+	
€/MWh-fuel	2030	2040	2030	2040	2030	2040	2030	2040
Nuclear	-	-	1.7	1.7	-	-	1.7	1.7
Lignite	7.9-11.4	7.9-11.4	-	-	-	-	4.0	4.0
Coal	-	-	9.2	9.2	-	-	15.5	24.9
Natural gas	34.2	37.0	31.2	34.0	34.2	37.0	34.2	37.0

5.2.2 *Carbon price and free allowances*

CPs are likely to join the EU GHG emissions trading scheme (ETS) at different speed with full compliance of most CPs only by 2040. However, the choice was made to consider harmonized carbon prices with the EU for all scenarios, and equal for all CPs and EU MSs, for both the 2030 and 2040 horizons, respectively. This study considered carbon prices of 60€/tonCO2 for 2030 and 100€/tonCO2 for 2040 for all CPs and the EU. These prices are closely aligned with the TYNDP-DE scenario (53€/tonCO2 by 2030 and 100€/tonCO2 in 2040), as well as with current future prices (EUA-Futures for December 2024 are 61€/tonCO2[122]).

This study further follows the EnC-Carbon Pricing study approach with respect to the gradual carbon price implementation in the CPs, with differentiated shares of free carbon allowances in each CP, shown in Table 38. This considers the structural limitations of certain CPs to quickly implement a carbon pricing regime.

[118] Georgia is in between three synchronous zones, thus not being able to operate synchronously with the three of them.
[119] GSE.
[120] The hypotheses on energy carrier prices are quite structuring considering their volatility. They condition the modelling results and should be kept in mind when contextualising the latter.
[121] Assumptions reflecting the situation by end-2021. It is important to remind that the present analysis does not take into account the consequences related to the invasion of Russia in Ukraine since 24 February 2022.
[122] https://www.theice.com/products/197/EUA-Futures/data

The modelling of free allowances was carried out as a stock constraint. In this approach, thermal generation fleets have access to a limited amount of free CO2 allowances, which are not subjected to a carbon price. If the stock is completely used up, then the thermal generation fleets will be completely subject to the carbon prices for the additional generation. This approach provides a good representation of power generation dynamics and of marginal price formation, as it reflects the marginal cost of the emission of an additional unit of CO2 through the auctioning process.

This approach requires to define a total stock of allowances per CP, to then compute the volume of free allowances given to the power generation sector in each CP. To define the total stock of carbon allowances for the power generation sector, we used the results of the EnC-CP study, Baseline scenario, which provides the total CO2 emissions per country, for the power generation sector. Then, the stock of free allowances can be computed based on this indicator and the share of auctioned allowances (cf. Table 38). Finally, carbon allowances were rescaled for the Moderate and Ambitious scenarios proportional to the remaining coal/lignite capacities in each country with respect to the Baseline scenario.

Table 38 - Auctioning rates for carbon allowances implemented in the power system modelling, based in EnC-CP study, 2021.

Country	2025	2030	2035	2040
Albania	100%	100%	100%	100%
Bosnia & Herzegovina	25%	30%	75%	100%
Georgia	100%	100%	100%	100%
Kosovo*	15%	35%	65%	100%[123]
Moldova	100%	100%	100%	100%
Montenegro	30%	65%	85%	100%
North Macedonia	30%	65%	85%	100%
Serbia	25%	30%	75%	100%
Ukraine	25%	30%	75%	100%

5.2.3 Investment potentials and cost evolution of selected technologies

This study analysed the optimal portfolio of additional flexibility sources to be installed in the EnC CPs to facilitate RES integration and the decarbonization of the power system. For this, the investment potential and costs of technology assets is required. We adopted the investment costs (capital expenditures (CAPEX) and fixed operational costs (FOC)) from the EU Reference Scenario 2020 Database[124], shown in Table 39. CAPEX was annualized using an 8.5% discount rate, and the lifetime of assets specified in Table 39.

[123] The EnC-CP study proposed an auctioning rate of 85% for Kosovo* in 2040. However, to better reflect the long-term phase-out in the allocation of free allowances, in this study we did not consider any free carbon allowance for Kosovo* in 2040 as full auctioning of carbon allowances is expected to happen from 2045 onwards.

[124] https://energy.ec.europa.eu/data-and-analysis/energy-modelling/eu-reference-scenario-2020_en

Table 39 - Overview of investment costs assumptions of flexibility assets subject to capacity optimisation

Technology	Lifetime [years]	2030 CAPEX [€/MW]	2030 FOC [€/MW.y]	2040 CAPEX [€/MW]	2040 FOC [€/MW.y]
OCGT[125]	25	386 000	11 700	383 000	11 600
CCGT[126]	30	579 000	21 000	575 000	20 000
Batteries[127]	15	190 000	15 000	150 000	13 100
Pumped Hydro Storage	60	900 000	20 300	880 000	20 000
PHS Extension[128]	60	270 000	6 090	264 000	6 000

Regarding the potential of installation of new flexibility technologies, we considered that there was no restriction to the siting of new OCGT, CCGT or large-scale battery facilities in any CP (i.e., there was an unlimited potential for the installation of these technologies). On the other hand, pumped hydro storage facilities are limited by the availability of suitable locations. PHS was considered as a potential flexibility asset only for identified projects[129], as follows:

- Georgia: 570 MW of potential new PHS investments.
- North Macedonia: 330 MW of potential PHS investment, related to the CEBREN project.
- Ukraine: Potential investments only in extensions of existing PHS facilities (no increase in storage capacity). Current PHS capacities amount to 1.83 GW, potentially rising to 1.98 GW in 2030 and 3.3 GW in 2040.

5.2.4 Techno-economic operational parameters

Generation assets of the same technology are clustered into a single asset per country for modelling purposes[130]. The different technology assets are modelled based on a set of technical and economic parameters, including minimum generation levels, ramping rates, availability, efficiency[131] and variable costs (excluding fuel and CO2 costs). These are shown in Table 40, coming mainly from the European Commission METIS data[132]. Hydro reservoir ramping rates were adapted to reflect historical usage of EnC-CPs assets, and lignite and coal ramping rates reflect start up times[133], which are not explicitly modelled in this study.

125 Gas turbine with heat recovery in EU Reference Scenario 2020 database.
126 Gas Turbine Combined Cycle Gas Advanced in EU Reference Scenario 2020 database.
127 Large-scale lithium-ion batteries in EU Reference Scenario 2020 database, considering a 2-hour discharge time capacity.
128 Considering a 30% of investments costs of a greenfield PHS project, following assumptions in K. Salevid, *Market Requirements for Pumped Storage Profitability*, August 2013.
129 There are two PHS projects in Serbia, which were not present in the dataset of this report.
130 The explicit modelling and optimization of every power generation plant is not computationally feasible given the size of the pan-European power system. For more information on the approach, see:
European Commission, Directorate-General for Energy, Chammas, M., Bossavy, A., Texier, B., et al., *METIS technical note T2 : METIS power market models*, European Commission, 2019, https://data.europa.eu/doi/10.2833/949996
131 Fuel efficiency for thermal power plants [MWh-elec/MWh-fuel], round-trip efficiency for PHS.
132 European Commission, *METIS Technical Note T6, METIS Power System Module*, 2017.
133 ENTSO-E, Pan European Market Modelling Database, 2020. Available: https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/PEMMDB%20National%20Estimates.xlsx

Table 40 - Main techno-economical parameter values implemented in the simulation tool.

Technology	Min. generation level	Ramping capability	Availability	Efficiency	Variable costs
Nuclear	40%	5 %/min	85%	33%	-
OCGT	0%	12 %/min	96%	36-42%	1.6 €/MWh
CCGT	0%	5 %/min	82%	40-60%	1.6 €/MWh
Coal	0%	0.25-0.33 %/min	77%	32-46%	3.3 €/MWh
Lignite	0%	0.25-0.64 %/min	84%	35-46%	3.3 €/MWh
Hydro reservoir	0%	0.42-0.61 %/min	90%	-	-
PHS	0%	Unconstrained	90%	81%	-
Li-Ion Batteries	0%	Unconstrained	100%	90%	-

5.3 Other main assumptions

5.3.1 Cross-border interconnection capacity

Two levels of cross-border exchange capacities (represented as net transfer capacity, NTC) are considered in this study, reflecting two market integration scenarios, *Fragmented market* and *Integrated market* scenarios. The fragmented market approach restricts the utilisation of NTC capacities to the values observed in the past, whereas the Integrated market approach makes available at least 70% of the nominal transmission capacities for trading purposes. This assumption reflects not only the provisions from the Regulation (EU) 2019/943 but possible construction of new interconnections as well.

No optimisation of interconnection capacities was considered. Thus, NTC capacities were considered as fixed input data. NTC values are shown in the figures below[134].

The Fragmented market approach was used as the base case for all scenarios. The Integrated market case was only considered for the Moderate and Ambitious scenarios, and only for the CPs connected to the Pan-European system (there is no Integrated market scenario for Georgia).

[134] NTC for both scenarios values provided by the EnC Secretariat.

To\From	AL	BA	GE	XK	MK	MD	ME	RS	UA	BG	GR	HR	HU	IT	PL	RO	SK	AM	AZ	RU	TR	Import
AL				400	600		441				400											1841
BA							500	600				1000										2100
GE																		0	1260	0	1050	2310
XK	400				291		300	325														916
MK	600			150				300		250	350											1050
MD									800							600						1400
ME	400	500		300				300						600								1700
RS		600		325	250		200			350		600	700			1222						4247
UA						1200							900		0	400	816					3316
BG					150			300														
GR	400				300																	
HR		1000						600														
HU								800	800													
IT							600															
PL									235													
RO						600		1100	400													
SK									674													
AM			0																			
AZ			1260																			
RU			0																			
TR			1050																			
Export	1800	2100	2310	1175	1591	1800	2041	4325	2909													

Figure 53 - Fragmented market (NTCs at all borders in both directions) [MW]

To\From	AL	BA	GE	XK	MK	MD	ME	RS	UA	BG	GR	HR	HU	IT	PL	RO	SK	AM	AZ	RU	TR	Import
AL				1019	837		1027				851											3732
BA							1257	1864				2931										6050
GE																		0	1260	0	1050	2310
XK	1019				767		830	1019														2615
MK	837			767				767		767	1084											3385
MD									1821							600						2421
ME	1027	1257		830				1183						600								3868
RS		1864		1019	767		1183			837		837	837			2478						9821
UA						1821							2294		297	806	1000					6218
BG					767			837														
GR	851				1084																	
HR		2931						837														
HU								837	2294													
IT							1200															
PL									297													
RO						600		2478	806													
SK									1000													
AM			0																			
AZ			1260																			
RU			0																			
TR			1050																			
Export	3732	6050	2310	3634	4222	2421	5495	9821	6218													

Figure 54 - Full market integration (NTC values at all borders in both directions equal to 70% of the nominal transmission capacities) [MW]

5.3.2 RES and demand profiles

Detailed renewable energy generation profiles are needed to assess the flexibility requirements of the electricity system. Year-long hourly resolution generation profiles per country for wind and solar PV were used as an input for the optimization model. Profiles for ENTSO-E members were obtained from the PECD database[135]. For Ukraine, Moldova, Kosovo* and Georgia, solar PV generation profiles were obtained using PV-GIS[136], and wind generation profiles were derived using MERRA-2 weather data[137][138].

[135] Pan-European Climate Database from the ENTSO-E. Previously stored on https://www.entsoe.eu/outlooks/seasonal/, page updated since with the new version of the PECD
[136] PV-GIS is an open access tool to assess solar irradiance and PV systems performance developed by the European Commission. https://joint-research-centre.ec.europa.eu/pvgis-photovoltaic-geographical-information-system_fr.
[137] MERRA-2 (*Modern-Era Retrospective analysis for Research and Applications, Version 2)* is a global atmospheric reanalysis produced by NASA, providing several atmospheric databases from 1980, including wind speed components with an hourly resolution.
[138] To obtain wind generation profiles, hourly wind speed components were obtained for a number of points from the MERRA-2 database, to then obtain wind generation profiles considering standard IEC Class wind power production curves.

Hydro generation is also subject to significant inter- and intra-annual variability. Run-of-river potential generation profiles, and inflow timeseries for hydro reservoirs for ENTSO-E members were obtained from the Pan-European Market Modelling Data Base (PEMMDB). Required data for Ukraine, Moldova, Kosovo* and Georgia were obtained from national stakeholders[139].

This study was based on the climatic year 2007, which represents an *average* year at the European scale[140].

Demand profiles are taken from the TYNDP 2020, which provided a database for 30 climatic years. For Ukraine, Moldova, Kosovo* and Georgia, demand profiles were obtained from relevant stakeholders. Demand profiles were rescaled to match the annual volumes determined for each scenario.

5.3.3 Demand response modelling

For demand side response, it is important to make assumptions about end users that could be operated in a flexible and smart manner by 2030/40.

Electric vehicles (EVs)

EVs are one of the key technologies to allow the decarbonization of the transport sector, and their large-scale deployment is expected in many EU MSs in the coming years. The uptake of EVs will generate additional electricity demand, potentially increasing flexibility requirements.

However, EVs can provide also flexibility by means of *smart charging* (adapting the charging process to market signals) and *vehicle-to-grid* (V2G, allowing the EV to *discharge*, providing power back to the grid when needed).

An explicit modelling of uncontrolled, smart charging and V2G-capable EVs was carried out for each CP. The EV penetration levels (with respect to 2020 vehicle stocks) and the shares of *smart* EVs per scenario are detailed in Table 41, defined based on CPs' projections. A more ambitious EV penetration assumption was considered for Ukraine, given their more ambitious position in this regard.

Table 41 - EV penetration and share of smart EVs per scenario.

	2030			2040		
	Baseline	Moderate	Ambitious	Baseline	Moderate	Ambitious
EV penetration						
CP8[141]	4%	5%	6%	6%	10%	14%
Ukraine[142]	15%	20%	25%	25%	33%	40%
Smart EVs share (equal for all CPs)						
Smart charging share	10%	20%	30%	20%	40%	60%
V2G share	0%	0%	0%	0%	10%	20%

[139] Ukrenergo for UA, Moldelectrica for MD, Ministry of Economy for XK* and GSE for GE.
[140] 2007 is the year with the highest *representativeness* for the European power system. ENTSO-E, *TYNDP 2020 Implementation Guidelines*. August 2021. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2020/FINAL/TYNDP2020_CBA_Implementation_Guideline_final.pdf
[141] WB6, Moldova and Georgia.
[142] During the data collection phase, Ukrainian stakeholders provided a forecast of 12 million EVs by 2040, while the stock of total vehicles in Ukraine was only around 10 million in 2021. A cross analysis with TYNDP 2020 assumptions

Heat pumps

In EU households, heating and hot water account for 79% of total final energy use and approximately 75% of heating and cooling is still generated from fossil fuels[143]. The electrification of the heating sector can provide significant emission reductions if coupled with low-carbon electricity generation. In particular, heat pumps appear as a main technology for the electrification of the heating sector, as they allow high-efficiency heating and cooling[144], reducing the total energy demand from the heating sector.

Additional electricity demand from electric heating can increase flexibility needs of the electricity system, in particular to deal with peak demand during extreme cold-weather events. Heat pump efficiency also decreases with cold weather, compounding the demand increase. Heat pumps can include a backup heater, either electric or gas-fired, to meet heating demand in during peak periods.

Smart heat pumps can provide flexibility at the daily scale by shifting the hours of activation of heat pumps according to market signals, system requirements or to high-efficiency periods along the day (when temperatures are higher), making use of the thermal inertia of buildings or dedicated thermal storage units. Electric backup heaters can be activated to meet heat demand, and gas-fired backups can be used during power scarcity periods. An example of the utilization of heat pump flexibility is shown in Figure 55.

In this study, heat pumps were not modelled as a flexibility asset due to lack of available data/targets from CPs on heat pump deployment.

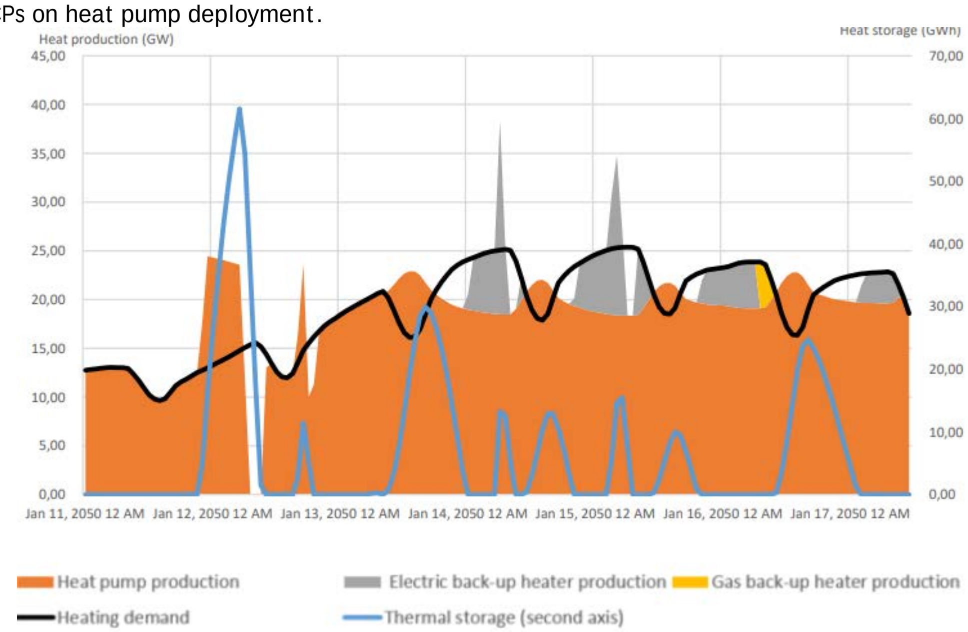

Figure 55 - Example of heat pump utilisation during one week of winter[145].

Electrolysers for hydrogen production

Hydrogen generation from electricity using electrolysers may become a significant component of future energy systems. Electrolysers can adapt their operation according to system needs and electricity prices,

showed an EV penetration rate in Eastern European countries (Poland, Slovakia, Romania) of around 40% by 2040. Hence, we decided to set EV penetration rates at a lower, more conservative value (between 15-25% in 2030 and 25-40% in 2040 with respect to 2021 stocks), but still higher than the rest of the Energy Community CPs given the more ambitious forecasts for Ukraine.

[143] Energy Community Secretariat. *Discussion Paper on How would heating and cooling sector contribute to EU 2030 decarbonisation goal - NECPs measures,* October 2021.

[144] Heat pumps have a nominal *coefficient of performance* (COP) around 3, meaning that for one unit of input energy (electricity), they can provide 3 units of heating/cooling. Conventional heating units are limited by a COP of 1.

[145] Artelys, Decentralised heat pumps: system benefits under different technical configurations : METIS Studies, study S6, Publications Office, 2019, https://data.europa.eu/doi/10.2833/800501

increasing the flexibility of the energy system. Combined with hydrogen storage and hydrogen-based power generation (through fuel cells or hydrogen turbines) electrolysers can provide a number of additional flexibility services to the electricity system. A hydrogen transmission infrastructure can also be developed to allow cross-border exchanges and balancing hydrogen requirements across countries, as well as allowing hydrogen production in cost-efficient locations.

Hydrogen electrolysers can provide flexibility at the daily and weekly scale, by adapting their operation times to high renewable generation periods. If coupled with large-scale hydrogen storage facilities and hydrogen-powered generators, they can also provide seasonal flexibility[146]. An example of daily and weekly flexibility of electrolysis-based hydrogen supply is shown in Figure 56. This figure depicts two EU MSs (Germany and France) by 2035, who have the possibility to do cross-border exchanges. Germany (top chart), relies heavily on imports from neighbouring countries, with local generation of hydrogen scheduled in high renewable generation periods (see the electrolysis peak during the first day, and subsequent smaller ones during high PV generation hours). France, on the other hand, acts as an exporter of hydrogen, with larger renewable-based hydrogen generation. Both MSs make use of hydrogen storage facilities to meet demand.

In this study, hydrogen electrolysis, storage and hydrogen-based power generation were not modelled as a flexibility asset due to lack of available data/targets from CPs on the future role of hydrogen.

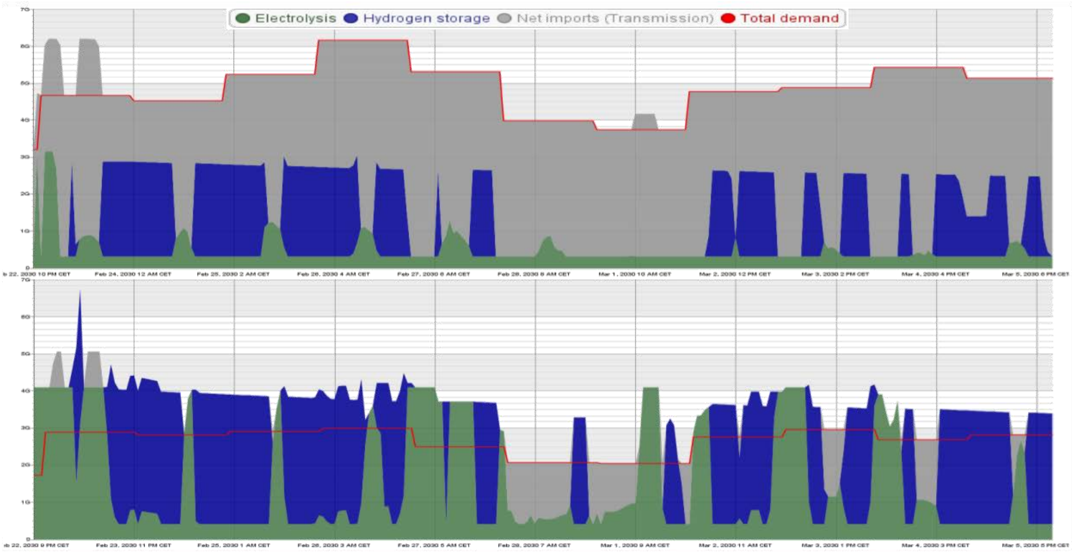

Figure 56 - Example for the hourly dynamics of the hydrogen supply and demand in Germany (top) and France (bottom) [147].

[146] The role of hydrogen storage for the power system will depend on technical and economic characteristics that are subject to great uncertainty.

[147] European Commission, Directorate-General for Energy, Vautrin, A., Bossmann, T., Beaussant, O., METIS study on costs and benefits of a pan-European hydrogen infrastructure : in assistance to the impact assessment for designing a regulatory framework for hydrogen : METIS 3, Study S3, Publications Office, 2021, https://data.europa.eu/doi/10.2833/736971

6 Cost-optimal flexibility portfolios: 2030 and 2040 results

This section presents the optimal flexibility portfolios for each CP to support decarbonization and RES integration. The analysis allows to derive the following three key messages:

- ✓ There is no need for additional flexibility investments in 2030.
- ✓ Investments in new flexible solutions remain low in 2040, despite the coal and lignite phase out.
- ✓ Going from a fragmented market to a market integration scenario decreases the need for flexibility from storage and thermal generation, and drives down CO2 emissions.

These results will be explained more thoroughly in separated sections.

6.1 Optimal flexibility portfolios by 2030

This section is focused on the optimal flexibility portfolios obtained for the year 2030, under the Fragmented market scenario. Results show no additional flexibility investments for any 2030 scenario. Given the moderate levels of RES across EnC CPs, in all scenarios, no major RES integration issues are foreseen (within the scope and assumptions of this analysis[148]). This section provides insights in the CPs' future power generation mix, how their existing assets contribute to the flexibility needs of the system, and what are the amounts of CO2 emissions under the different scenarios.

6.1.1 Generation mix in 2030

In 2030, CPs already see their production mix being significantly altered with the penetration of vRES:

- ✓ From 5% to 25% of vRES supply in the Baseline 2030 across CPs
- ✓ From 15% to 32% of vRES supply in the Ambitious scenario 2030 across CPs

The detail per CP is presented on Figure 57.

Three CPs show a significant lack of domestic supply compared to their consumption already in the Baseline scenario: Moldova, North Macedonia and Kosovo*. A decrease of coal/lignite capacities not sufficiently compensated by RES integration increases this phenomenon in the Ambitious scenario. In the Ambitious scenario, significant import dependency also appears for Montenegro and Serbia, with imports covering over 15% of national demand under the given scenario assumptions. Bosnia & Herzegovina appears as the only country with significant generation surplus, exporting around 15% of its national production in the Baseline scenario. However, due to lignite power decommissioning which is not sufficiently compensated by an increase in vRES, Bosnia & Herzegovina becomes a net importer in the Ambitious scenario.

[148] Congestions in the internal transmission or distribution system are not considered in this study, which recent reports have highlighted for the region. See for example: European Commission, Directorate-General for Energy, *Study on the Central and South Eastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables: final report,* 2022.

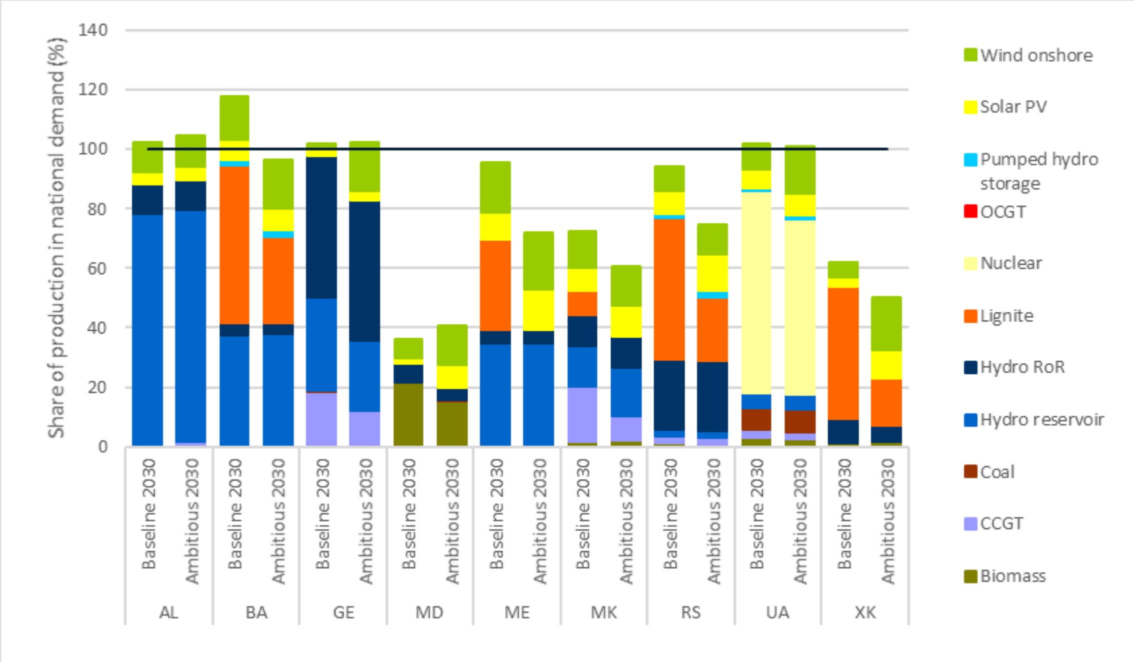

Figure 57 - Share of production in national demand (%) in 2030 for baseline and ambitious scenario

6.1.2 Existing flexible assets

The existing flexible assets are significant in 2030 as can be seen in Figure 58. The main capacities are interconnections with neighbouring countries (around 20 GW of import NTC). Hydropower, combining hydroelectric reservoirs and PHS, is the second source of flexibility with slightly more than 15 GW and is present in almost all of the Contracting Parties (except for Kosovo* and Moldova). These assets are of particular importance in Ukraine, Georgia and Albania. Nuclear capacities rank third at the EnC level, but are only present in Ukraine (15 GW). Finally, coal and lignite account for 13 GW in the Energy Community in 2030.

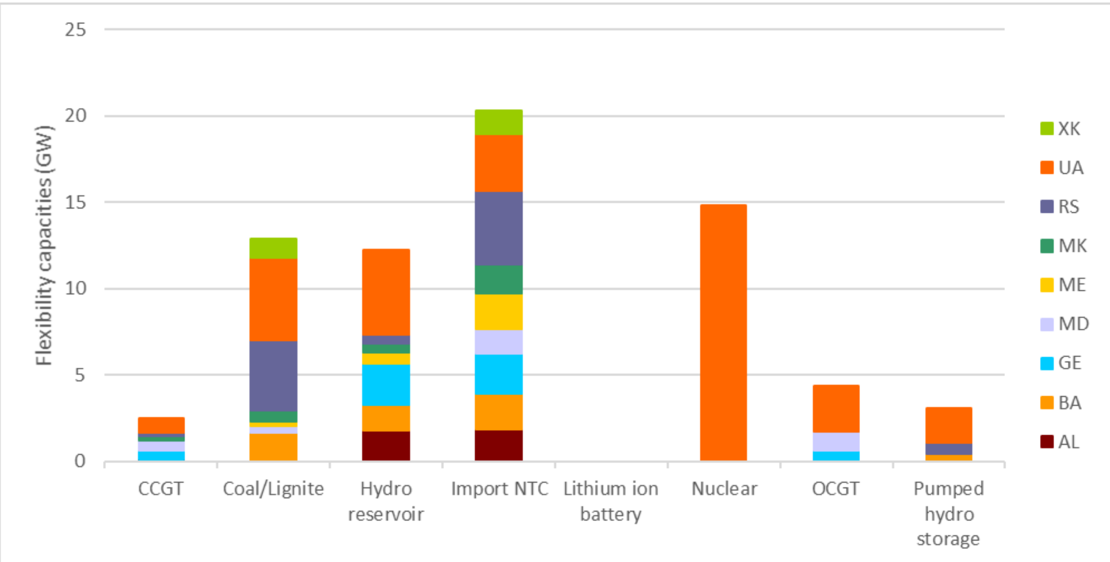

Figure 58 - Flexibility capacities in Baseline 2030 scenario

6.1.3 Contribution to flexibility needs

Overall flexibility needs increase with a more ambitious vRES deployment, especially daily and weekly needs. Increase in annual flexibility needs is more limited, as wind and PV generation have complementary seasonal generation patterns (wind has higher production during winter months, whereas PV has higher production in summer months). Coal/lignite, CCGT, hydropower and interconnections are the main providers of flexibility at all timescales in 2030, as can be seen in Figure 59.

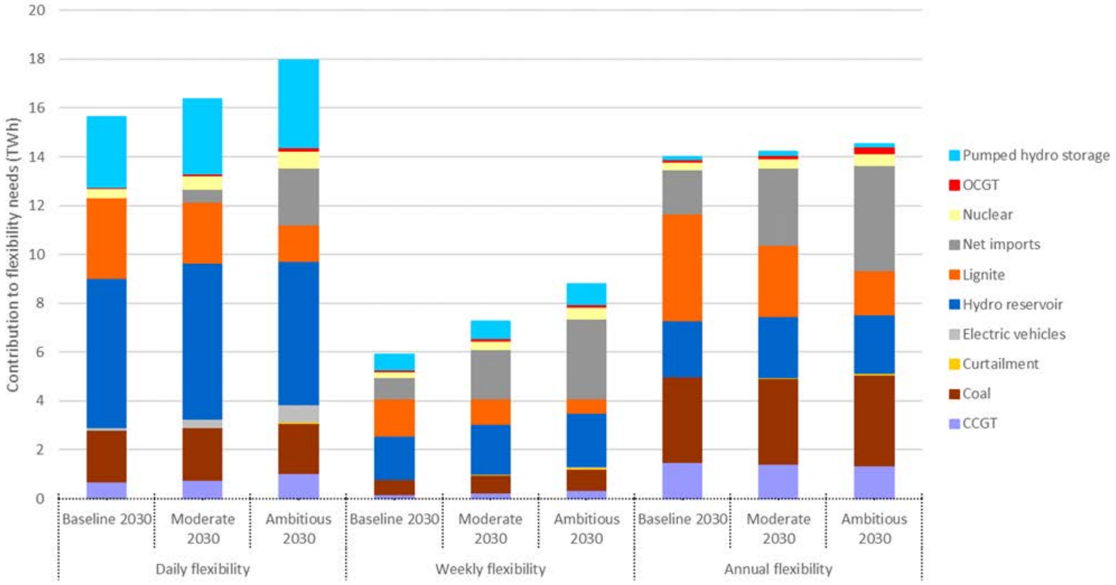

Figure 59 - Contribution to flexibility needs in 2030

- At a daily scale, hydro power plants are the main flexibility source, combining reservoirs and PHS, covering on average 55% of flexibility needs. Lignite, coal and CCGT follow, with net imports having a lesser role, being limited mostly to the Ambitious scenario (to compensate for the reduced production from lignite capacities). In scenarios where the penetration of EV is more ambitious, the share of their contributions starts to get significant.
- At a weekly scale, hydro and imports dominate the contribution to flexibility needs. In particular, imports' flexibility contribution increases significantly in the Ambitious scenario, created by the reduction of lignite capacities (and its flexibility contributions) and the increase of flexibility needs.
- At an annual scale (where the evolution of flexibility needs remains relatively constant between scenarios), coal/lignite are the main flexibility providers (45% on average). Hydro, CCGTs and imports supply a large share of the remaining flexibility needs.
- Lignite contribution to flexibility needs decreases across scenarios, as installed capacities decrease. This decrease is largely compensated by interconnections. Coal contributions remain relatively stable, as installed capacities (mainly in UA) remain the same across scenarios.
- Interconnections contribute to flexibility needs along all timescales, with an increasing role in more ambitious scenarios. This highlights the importance of regional cooperation to balance supply and demand. Note, the net imports represented in Figure 59 include exchanges between EnC CPs (and not only with neighbouring EU MS). This means that a significant share of interconnection flexibility can be provided by exchanges among WB6 countries and through the UA-MD interconnection, thus not all interconnection flexibility is provided by EU countries.

6.1.4 CO2 emissions and free carbon allowances[149]

Direct CO2 emissions from the power sector in the CPs are dominated by coal and lignite emissions, as shown in Figure 60. A decrease of CO2 emissions is observed from the Baseline to the Ambitious scenario in 2030, in line with the decrease of installed lignite capacities. The carbon intensity of national generation per CP is shown in Figure 61. WB6 countries, excluding Albania, have the highest carbon intensity in the Baseline scenario, led by Kosovo*, Serbia and Bosnia and Herzegovina. The decommissioning of lignite power plants in the Ambitious scenario allows to significantly reduce their CO2 emissions, especially for Kosovo*, North Macedonia and Montenegro. Ukraine and Georgia present a generation mix with a carbon intensity around 100 kg/MWh, and Albania and Moldova close to 0. However, the low carbon intensity of Moldova's generation is due to its reliance on imports (see Section 6.1.1).

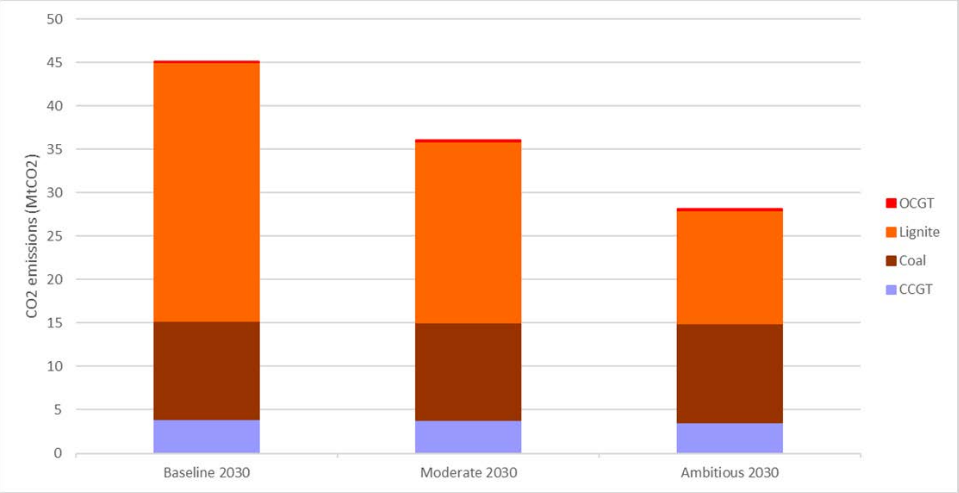

Figure 60 - CO2 emissions across 2030 scenarios (Mton CO2)

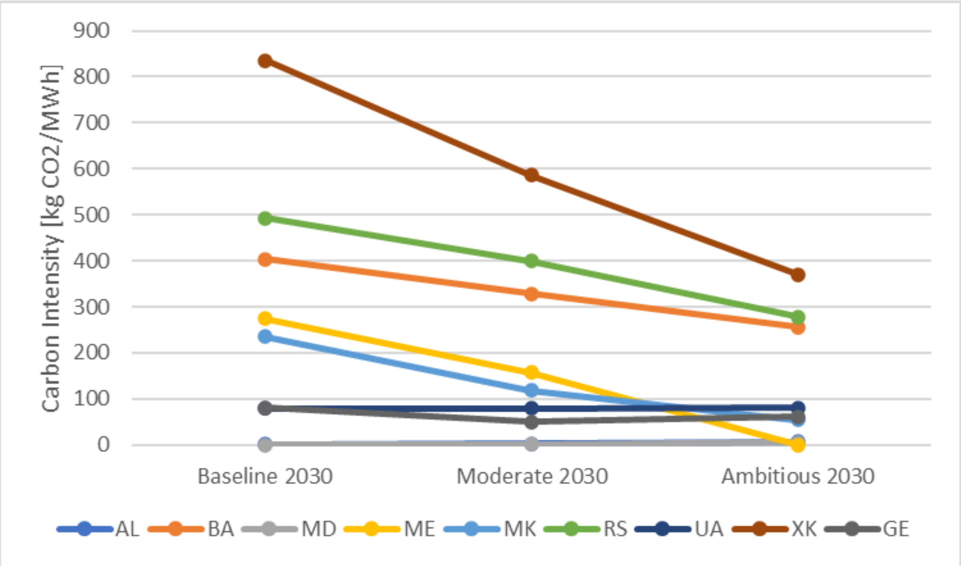

Figure 61 - Carbon intensity of national generation per CP and scenario, 2030 [kg CO2/MWh] (only direct emissions from the burning of fossil fuels)

149 This section considers only direct CO2 emissions from the burning of fossil fuels in domestic power generation. Indirect emissions from the construction and decommissioning, fuel extraction and processing, and other aspects that are out of the scope of this work.

Figure 62 shows the CO2 emissions per country and 2030 scenario, as well as the volume of free carbon allowances. Free carbon allowances set an indicative cap on CO2 emissions, already by 2030, with notably Georgia, Montenegro and Bosnia & Hercegovina exceeding the volume of free carbon allowances. This means that the considered CO2 price of 60 €/tonCO2 is already sufficiently high to significantly reduce emissions in the EnC CPs.

Three countries have no free carbon allowances, Albania, Georgia and Moldova. As Albania's power system is mainly relying hydro and energy self-sufficient, this does not provide major issues. On the other hand, Moldova is currently highly reliant on electricity imports, amounting to 81% of national demand in 2020[150], a situation which is maintained in 2030 as the carbon price limits the domestic generation from existing sources[151]. Moldova also benefits from low-cost generation from Ukraine, who has free carbon allowances, limiting the development of local generation.

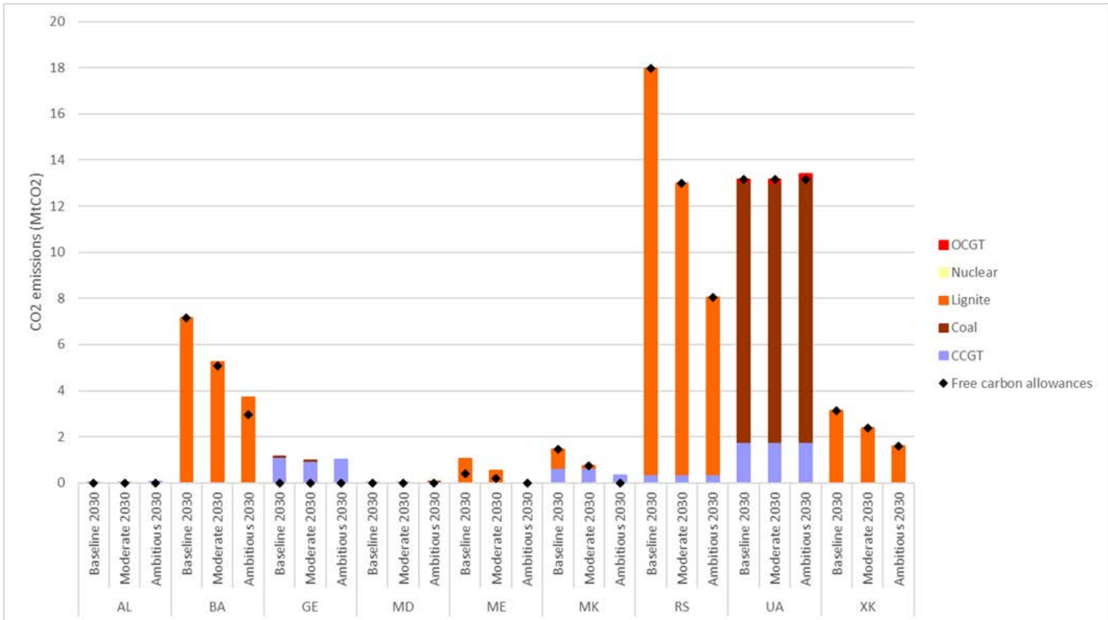

Figure 62 - CO2 emissions and free carbon allowances per country per scenario for 2030.

6.1.5 Conclusions for the 2030 horizon, fragmented market scenario.

The existing flexible capacities are significant in 2030:

- ✓ Around 20 GW of NTC in both imports and exports direction make the CPs well interconnected.
- ✓ Around 15 GW of hydropower (including PHS) assets are available in Albania, Georgia and Ukraine.
- ✓ Around 15 GW of nuclear capacities exist in Ukraine.
- ✓ Around 13 GW of coal/lignite assets exist in total in the Energy Community.

Flexibility needs increase with rising the vRES deployment between the Baseline and the Ambitious Scenario (+20% at a daily granularity, +49% at a weekly granularity and +3% at the annual timescale).[152] Hydropower and coal/lignite provide a high share of flexibility at all timescales in the Baseline scenario.

[150] https://www.iea.org/reports/system-integration-of-renewables-in-moldova-a-roadmap/context-of-renewables-in-moldova-s-electricity-sector
[151] Moldova has 2096 MW of thermal generation (coal, hybrid coal-gas, and biomass-based from sugar refineries), most of which is ageing and present low combustion efficiency.
[152] Bearing in mind that the RES penetration level could even be higher, beyond the Ambitious scenario levels, as of 2030.

Additional flexibility in the Ambitious scenario is mainly provided by imports, compensating also for the reduction in lignite-based power production linked to national phase-out strategies.
From the Baseline to an Ambitious scenario, the reduction of CO2 emissions is significant (-38%), as lignite/coal capacities are decommissioned.

6.2 Optimal flexibility portfolios by 2040

This section focuses on the optimal flexibility portfolios required in the Energy Community by the year 2040, under the Fragmented market scenario. This section analyses in detail the overall supply mix, the additional flexibility investments, the contribution to flexibility needs by different technologies, and related CO2 emissions.

The key takeaway from this section is that the investments in flexibility assets required by 2040 are low (under the scenario assumptions), and that they are needed mainly in CPs with ambitious coal phase-out policies.

6.2.1 Generation mix in 2040

In 2040, CPs see their production mix dominated by vRES following coal/lignite phase out, as depicted in Figure 63. Renewables allow to maintain or increase self-sufficiency, going from 15% to 68% of production in national demand depending on the individual CPs in the Ambitious scenario. Gas plays a continuously important role as energy carrier in Georgia, Moldova and North Macedonia. It also plays an increasingly important role in Ukraine, Kosovo* and Serbia in the Ambitious scenario due to stronger decarbonization efforts and the lack of additional nuclear capacities in Ukraine[153].

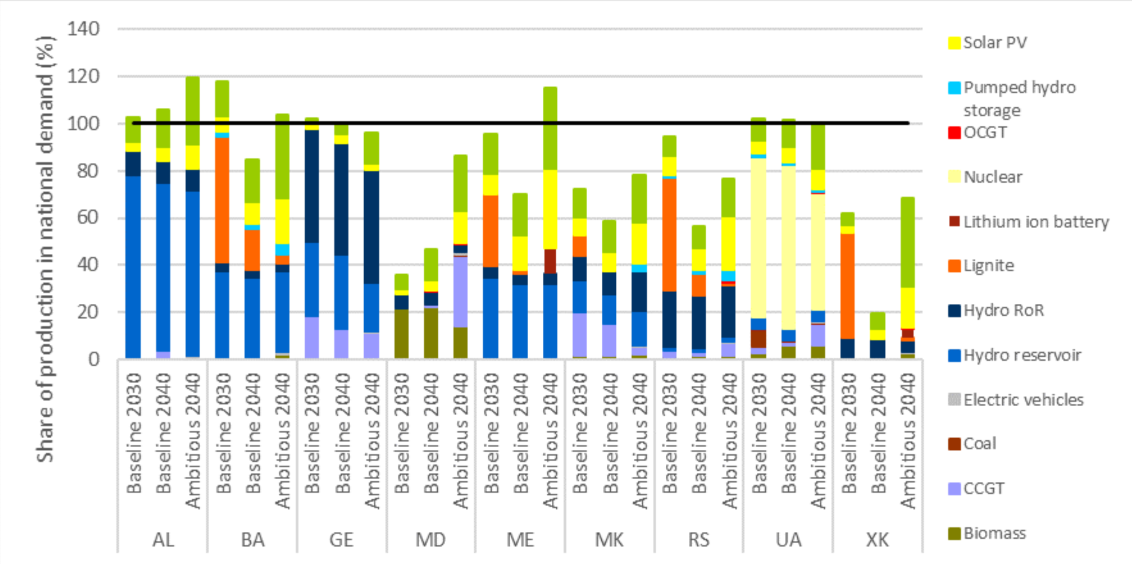

Figure 63 - Share of production in national demand (%) for Baseline 2030, Baseline 2040 and Ambitious 2040

6.2.2 Investments in power generation assets

[153] It is recalled that the Baseline scenario considers further development of nuclear capacities in Ukraine, going from 14.8 to 19.2 GW, whereas the Ambitious scenario considers a slight reduction, to 13.1 GW.

Additional CCGT investments

As a reminder, existing/planned CCGTs account for 2.5 GW in the CPs, mostly in Ukraine, Moldova and Georgia. The installation of new CCGT fleets occurs for countries facing a lack of supply in 2040 and often reaching the maximum capacity of their imports (Ukraine, Moldova, Serbia, Kosovo*), cf. Figure 64. In addition, Ukraine and Moldova are assumed to benefit from lower gas prices than EU/WB6[154], which explains a higher viability to install gas turbines.

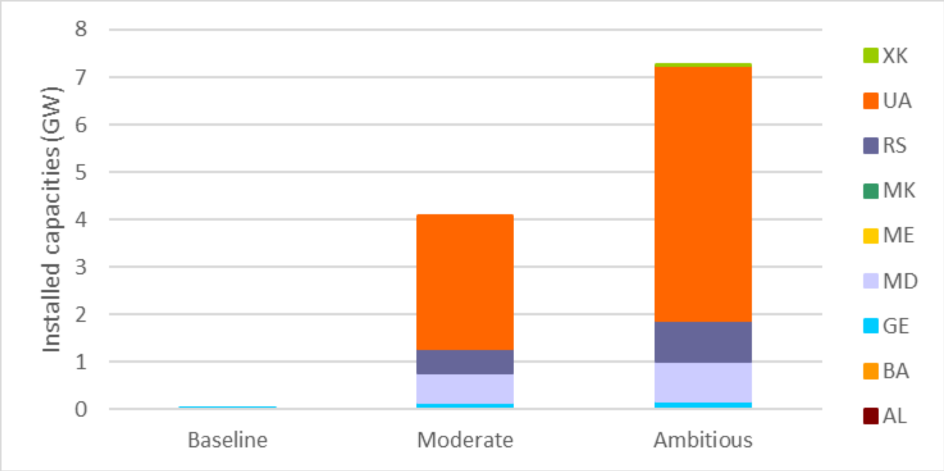

Figure 64 - Additionally installed CCGT capacities in 2040

Focus on CCGT investments in Moldova in the Ambitious scenario

Moldova's production mix only meets 50% of demand without CCGTs. The lack of competitive supply sources makes the country reliant on either gas or electricity imports. CCGTs are used when competitive imports are not available, as can be depicted in Figure 65.

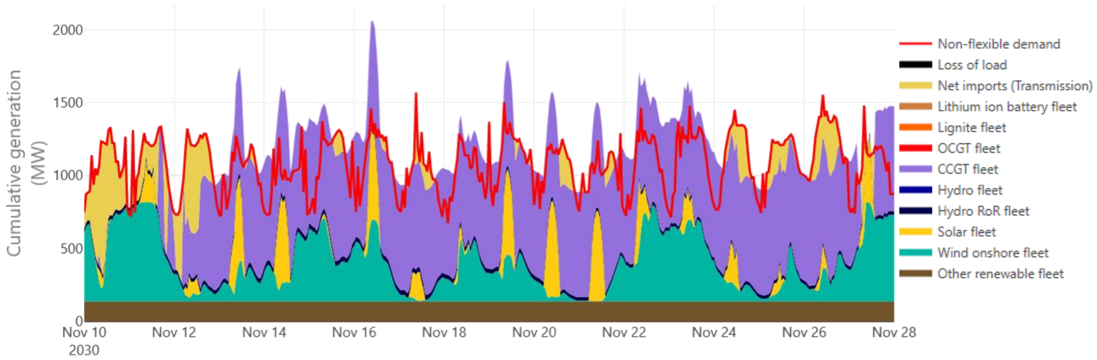

Figure 65 - Hourly cumulative generation (MW) in Moldova for two weeks in November, Ambitious 2040 scenario

Focus on CCGT investments in Georgia in the Ambitious scenario

Across all scenarios, Georgia's power production mix remains mainly based on hydroelectricity, with a share in generation decreasing from 79% in the baseline 2030 scenario to 69% in the Ambitious 2040 scenario. The deployment of wind and solar energy balances a strong demand increase. Due to lower hydro production during winter months, Georgia remains reliant on CCGT generation to ensure supply

[154] The energy carrier price assumptions were agreed with the EnC-Secretariat, reflecting a vision that did not take into account the war in Ukraine. Further studies would be needed to assess the role of gas considering the most recent geopolitical events.

adequacy. Therefore, the share of CCGT in production remains significant, from 19% in the Baseline 2030 to 12% in the Ambitious 2040 scenario with yearly capacity factors reaching 50%. CCGT capacities are not needed during spring and summer months, when hydro generation is high, as can be seen in Figure 66.

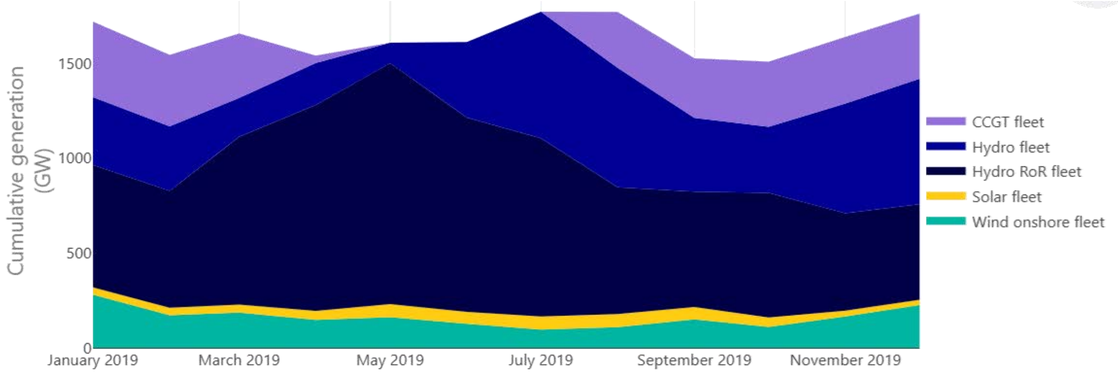

Figure 66 - Monthly cumulative generation in Georgia, Baseline 2040 scenario

Additional OCGT investments

It is recalled that the existing/remaining OCGT capacities will only be present in Ukraine and Moldova (accounting for 2.2 GW in 2040). Additional OCGT generation is needed in Serbia and Bosnia Herzegovina as peak power plants to cope with lignite phase-out by 2040 in the Moderate and Ambitious scenarios (cf. Figure 67). Thus, OCGTs fulfil a complementary role to CCGTs. OCGTs are used only a few hours per year, during periods of high net demand (high demand and/or low vRES generation), whereas CCGTs, due to their higher fuel efficiency, are used more frequently throughout the year.

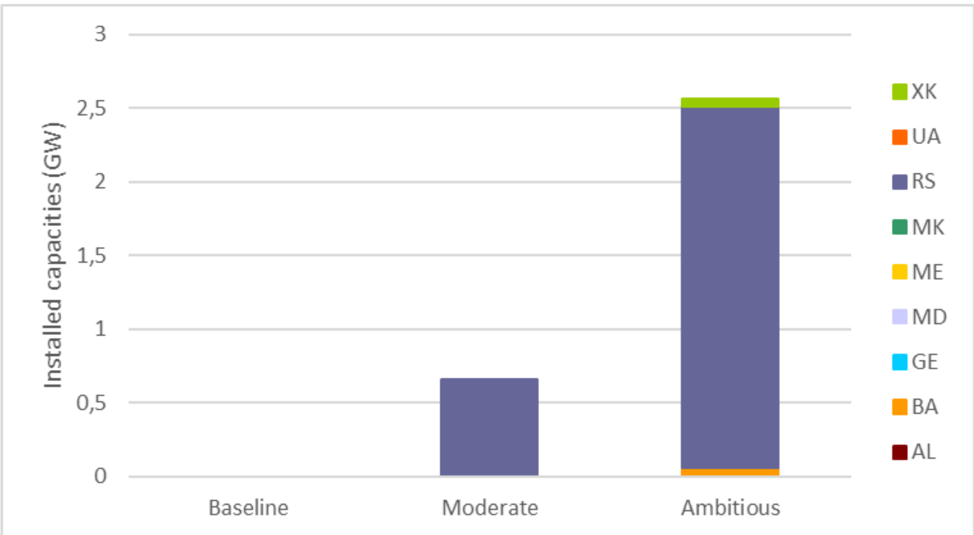

Figure 67 - Additionally installed OCGT capacities in 2040

Focus on Serbia and Bosnia Herzegovina in the Ambitious scenario

Dunkelflaute periods[155] can occur across the WB6, requiring high imports to meet demand. Coal phase-out in the Ambitious scenario makes Serbia rely highly on imports in periods of low-RES generation. OCGT fleets are installed to supply peak demand (cf. Figure 68).

[155] *Dunkelflaute* periods characterised by no or very little wind and PV production, typically combined with high demand.

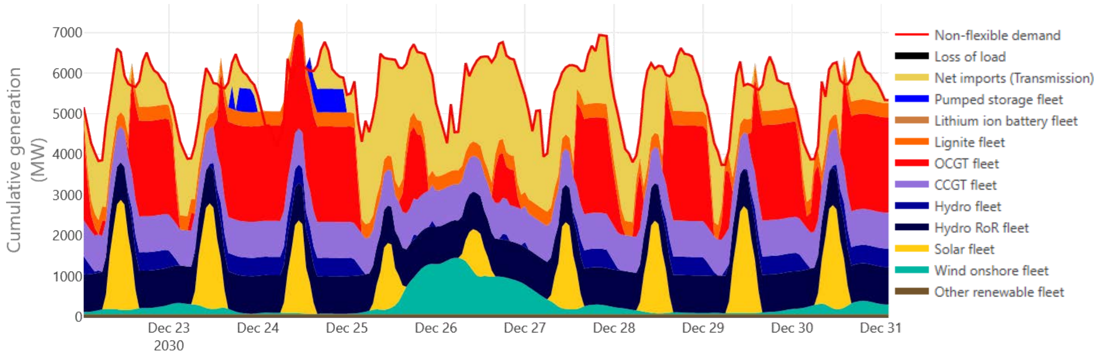

Figure 68 - Hourly cumulative Generation (MW) in Serbia for one week in December, Ambitious 2040 scenario

Bosnia and Herzegovina is likewise facing a coal phase-out. Even if the domestic hydro generation allows for higher self-generation, during Dunkerflaute periods the CP still needs backup supply. OCGTs are used to complement the generation mix, cf. Figure 69.

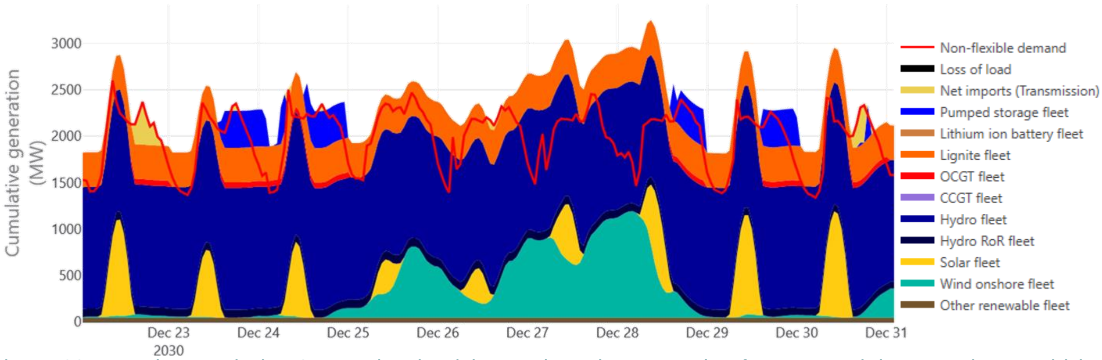

Figure 69 - Hourly cumulative Generation (MW) in Bosnia and Herzegovina for one week in December, Ambitious 2040 scenario[156]

6.2.3 Investments in storage assets (PHS and batteries)

Lithium-ion battery capacities

Large-scale stationary batteries are installed in the moderate and ambitious scenario as can be seen in Figure 70:

- ✓ In the Moderate scenario: around 400 MW in Montenegro and 300 MW in Kosovo*
- ✓ In the Ambitious scenario: around 350 MW for Montenegro, 1 150 MW for Kosovo* and 100 MW for North Macedonia

Batteries are needed in CPs where the renewable share is extremely high. This is the case of Kosovo*, where vRES reaches 80% of installed capacity, and Montenegro where vRES reaches 73%.

[156] OCGT capacities are small, their generation (red-shadowed areas) is shown between hydro and lignite production.

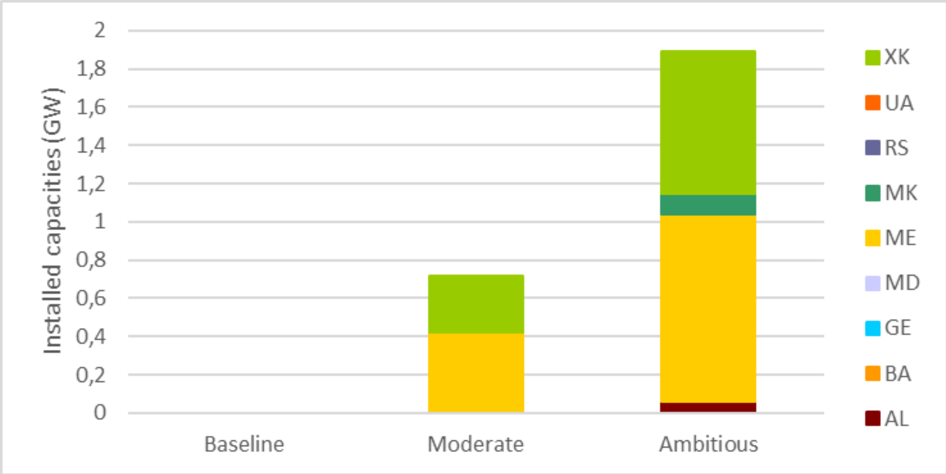

Figure 70 - Additional lithium-ion battery installed capacities in 2040

Focus on Montenegro in the Ambitious scenario

During summer, Montenegro uses a share of its solar PV surplus (and imports) to charge its batteries and reduce its imports at peak hours, as presented in Figure 71.

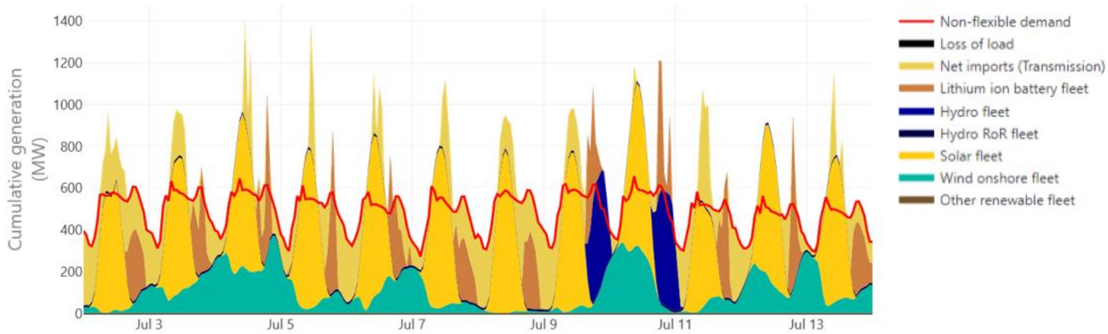

Figure 71 - Hourly cumulative Generation (MW) in Montenegro for one week in July, Ambitious 2040 scenario

During winter, batteries are used at peak hours either for export towards Bosnia and Herzegovina or Serbia or to meet domestic consumption, as seen in Figure 72.

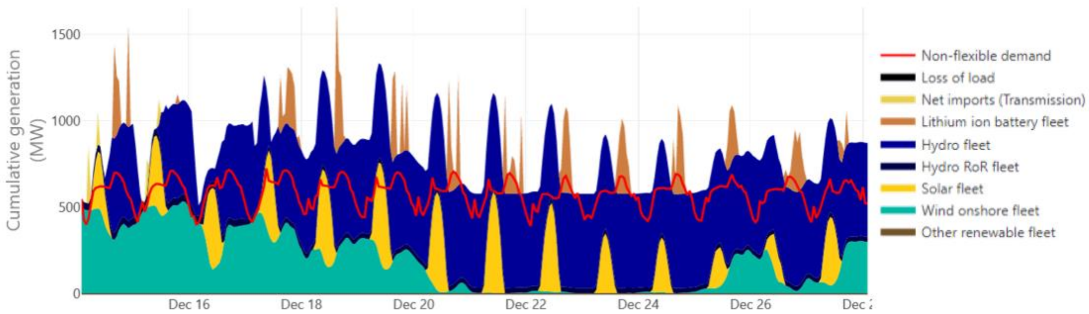

Figure 72 - Hourly cumulative Generation (MW) in Montenegro for one week in December, Ambitious 2040 scenario

Focus on Kosovo* in the Ambitious scenario

During summer, Kosovo* uses either its surplus of RES (solar and wind) or the one of Montenegro (solar) and Albania (hydro) to charge its batteries. It then discharges them during peak hours to reduce its imports or to export towards neighbouring countries (cf. Figure 73).

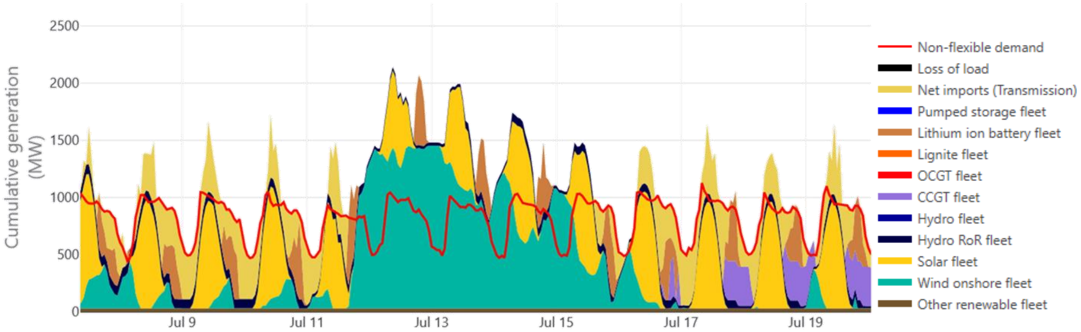

Figure 73 - Hourly cumulative Generation (MW) in Kosovo* for one week in July, Ambitious 2040 scenario

At low wind production, when batteries are empty/discharged, Kosovo* uses all the imports it can from Albania and North Macedonia (being the transit of either Bulgaria or Greece surplus) as can be seen in Figure 74.

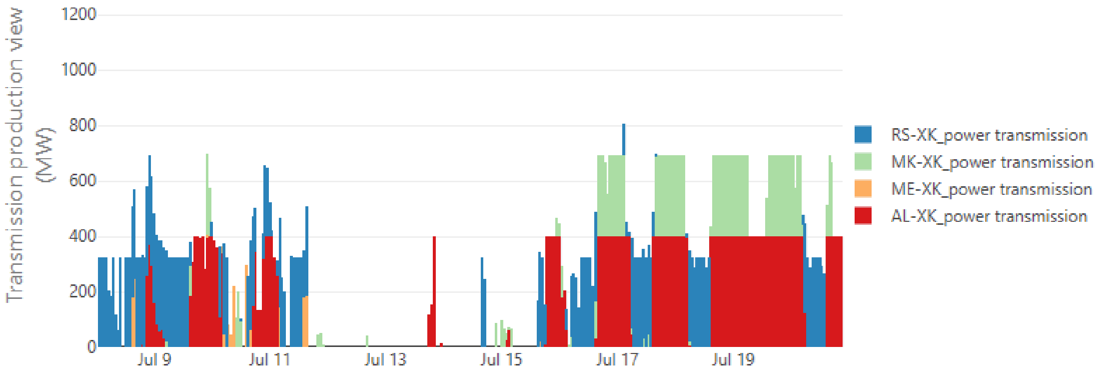

Figure 74 - Hourly cross-border flows (MW) in the import direction for Kosovo* for one week in July, Ambitious 2040 scenario

Pumped hydro storage

Existing PHS accounts for 3 GW in the Energy Community (2 GW in Ukraine, 650 MW in Serbia and 440 MW in Bosnia and Herzegovina). In 2040, additional capacities are installed in almost all scenarios in North Macedonia (from 100 MW to 170 MW, reaching 5% of total installed capacities) and in Ukraine (from 25 MW to 600 MW), cf. Figure 75. There is no need for pumped hydro storage capacities in Georgia, given the large hydro reservoir capacities existing and planned in the country, which provide most of the required flexibility[157].

Pumped hydro storage is used to provide flexibility at the daily or weekly timescales.

[157] The Ambitious 2040 scenario, which shows the higher flexibility needs, also envisions the development of additional hydro reservoirs. However, the construction of these additional hydro reservoirs are uncertain.

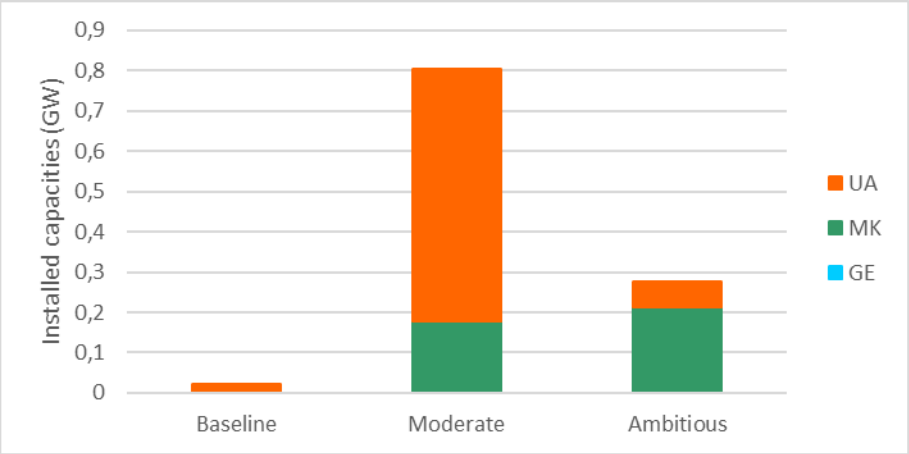

Figure 75 - Additionally installed pumped hydro storage capacities in 2040

Focus on North Macedonia and Ukraine in the Ambitious scenario

North Macedonia is supplying 80% of its own production. It uses the RES surplus of its neighbouring countries (solar) to reduce its imports at peak hours (with PHS) as presented in Figure 76.

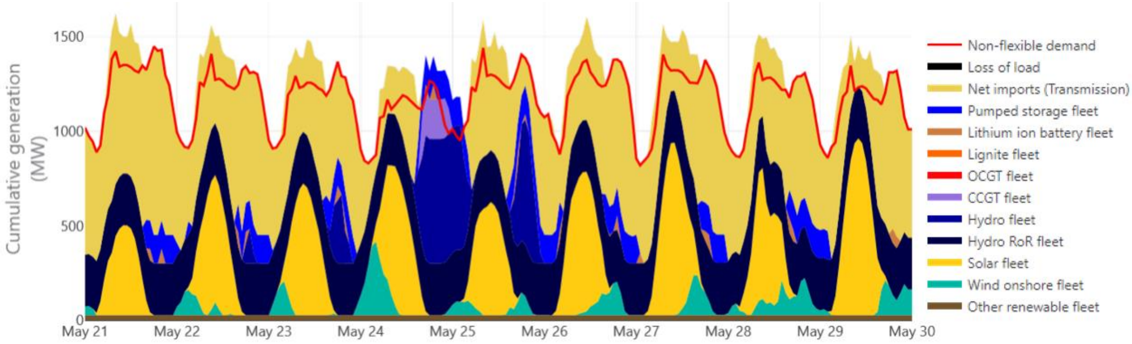

Figure 76 - Hourly cumulative Generation (MW) in North Macedonia for one week in May, Ambitious 2040 scenario

Ukraine uses its pump storage fleet either for peak hours or exports at those times to meet simultaneous peak demand in neighbouring countries (Figure 77). Pumped hydro storage absorbs PV generation, allowing cost efficient nuclear power plants to operate at a higher level (i.e., close to base load) during midday.

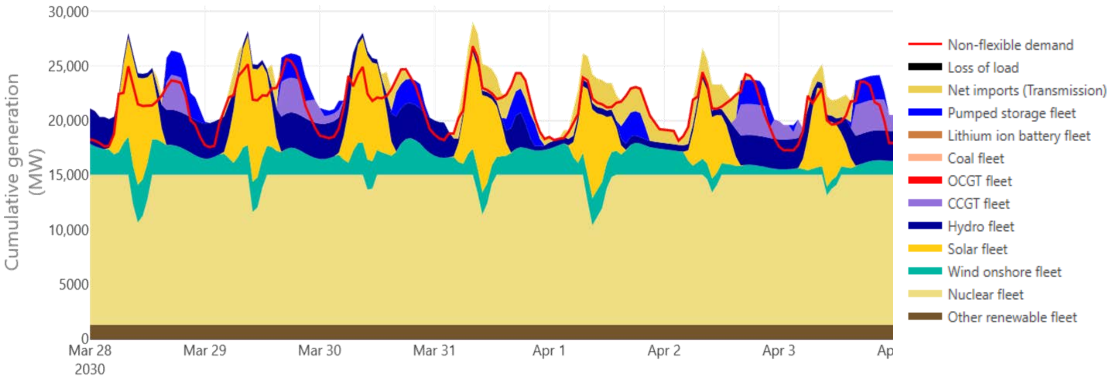

Figure 77 - Hourly cumulative Generation (MW) in Ukraine for one week in April, Ambitious 2040 scenario

6.2.4 Contribution to flexibility needs

The investments in flexibility solutions by 2040 will contribute to meet flexibility needs of the individual Contracting Parties. This section analyses them per regions (WB6, Moldova/Ukraine and Georgia), with detailed needs per CP provided in the Annex C (cf. Section 8).

Contribution to flexibility needs in WB6

Hydropower plants (including PHS), interconnections and CCGTs are the main provider of flexibility in 2040 for all timescales (Figure 78). The more ambitious the RES deployment, the more flexibility is needed at the different timescales.

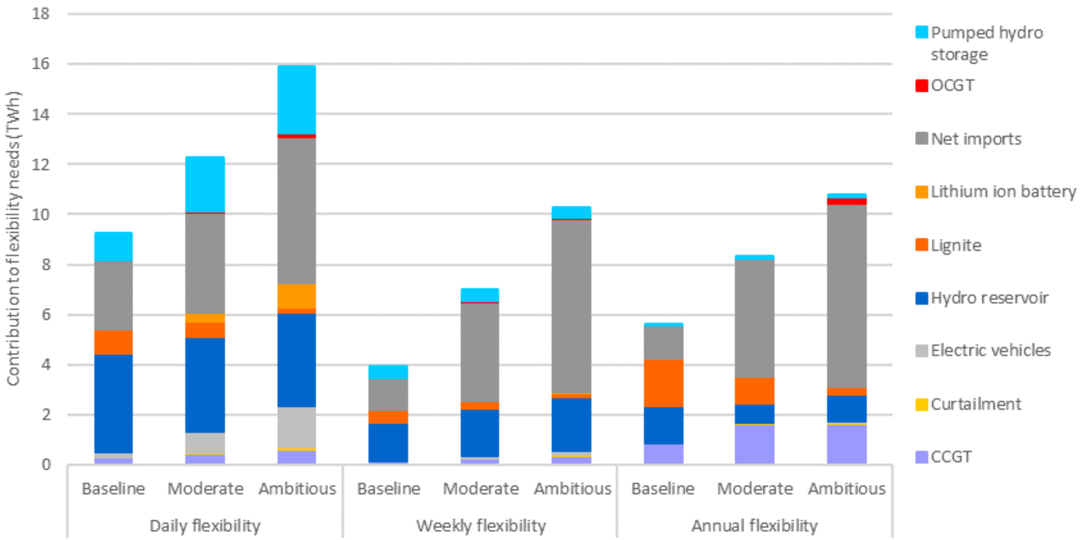

Figure 78 - Contribution to flexibility needs - WB6

- ✓ At a daily scale, hydro power plants are the main flexibility providers, both reservoir-based and PHS. Net imports complete the portfolio of contributors, followed by electrical vehicles and batteries.
- ✓ At a weekly scale, hydro and imports share the contribution to flexibility needs. The more ambitious the scenario is, the more the interconnections contribute.
- ✓ At an annual scale, lignite capacities still represent a high share in the scenario where the quantity is still significant (baseline scenario mostly). Imports (and CCGT to a lesser extent) take the lead on other scenarios.
- ✓ Interconnections contribute to a large share of flexibility needs along all timescales, with an increasing role in more ambitious scenarios. This highlights the importance of regional cooperation to balance the grid. It should be noted that the net imports represented in Figure 78 also include the exchanges between WB6 countries. This means that a significant share of interconnection flexibility is provided by intra-WB6 interconnection, and not all interconnection flexibility is provided by EU countries.

Contribution to flexibility needs in Ukraine and Moldova

In Ukraine and Moldova, nuclear and CCGTs are the main providers of flexibility in 2040, with some variations depending on the type of flexibility needed (cf. Figure 79). It is important to note that net imports at the annual timescale contribute negatively to flexibility needs. This means that neighbouring countries are using the available flexibility means of Moldova/Ukraine to balance their need, thus increasing the flexibility needs in these Contracting Parties. It also highlights the high level of flexibility of these countries (mainly Ukraine), who is not only capable of providing flexibility to meet its own needs, but also to meet the ones of their neighbouring countries.

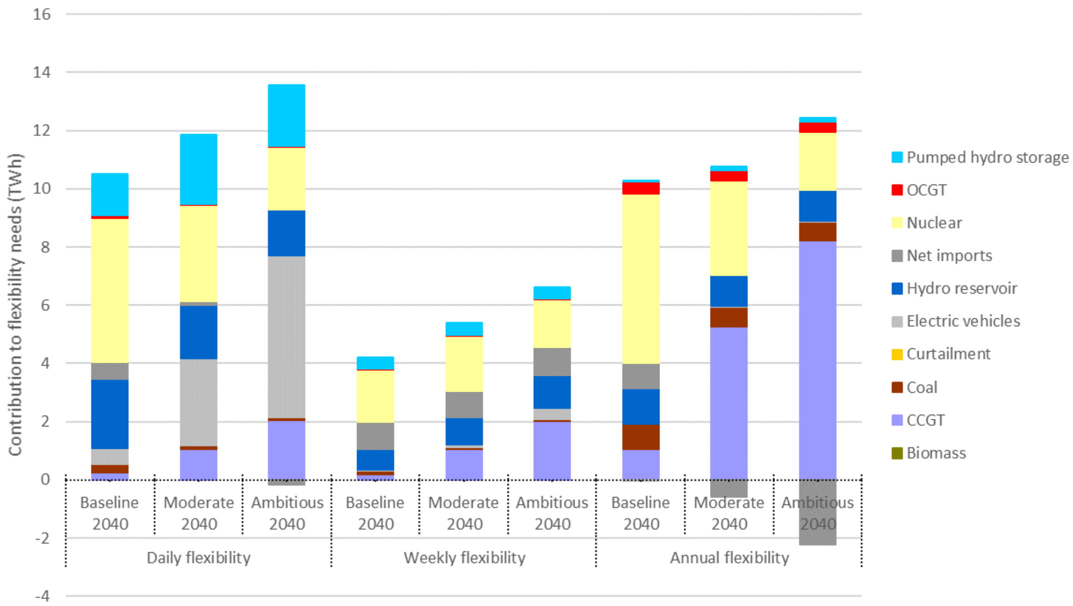

Figure 79 - Contribution to flexibility needs - Moldova and Ukraine

- ✓ At a daily scale, nuclear, hydroelectricity (PHS included) and EVs are the main flexibility providers. In particular, EVs become the main flexibility provider at this timescale in the Ambitious scenario, driven by a significant penetration level (4 million EVs in Ukraine by 2040) and a relevant share of EVs being smartly recharged: 60% smart charging-capable and 20% V2G-capable. This allows EVs to recharge during low net demand periods, contributing to the balance of the power system.
- ✓ At a weekly scale, nuclear is the main provider for all scenarios, with CCGTs gaining a significant role in the Ambitious scenario.
- ✓ At the annual timescale, generation assets, mainly nuclear and CCGTs are the main providers of flexibility. CCGTs take a larger role in the Ambitious scenario as there are additional installed capacities to compensate for lower nuclear capacities (in comparison to the Baseline scenario).

Contribution to flexibility needs in Georgia

In Georgia, the main providers of flexibility are hydro reservoirs and CCGT capacities (Figure 80). Flexibility needs are significantly higher in the Ambitious 2040 scenario due to a higher share of renewable capacity, which also results in a higher use of interconnection capacity. However, the Ambitious 2040 scenario is also accompanied by an increase in hydro generation capacities allowing to provide the additional flexibility.

- ✓ At a daily scale, hydro reservoirs are the main flexibility providers. Electric vehicles appear to provide a certain share of flexibility in the Ambitious scenario, as they penetrate the market.
- ✓ At a weekly scale, flexibility needs are lower. Hydro reservoirs are also the main flexibility providers.
- ✓ At the annual timescale, the contribution of CCGTs is more significant as their generation helps to balance the seasonal variation in the residual load (high CCGT generation in winter months when hydro generation is lower).

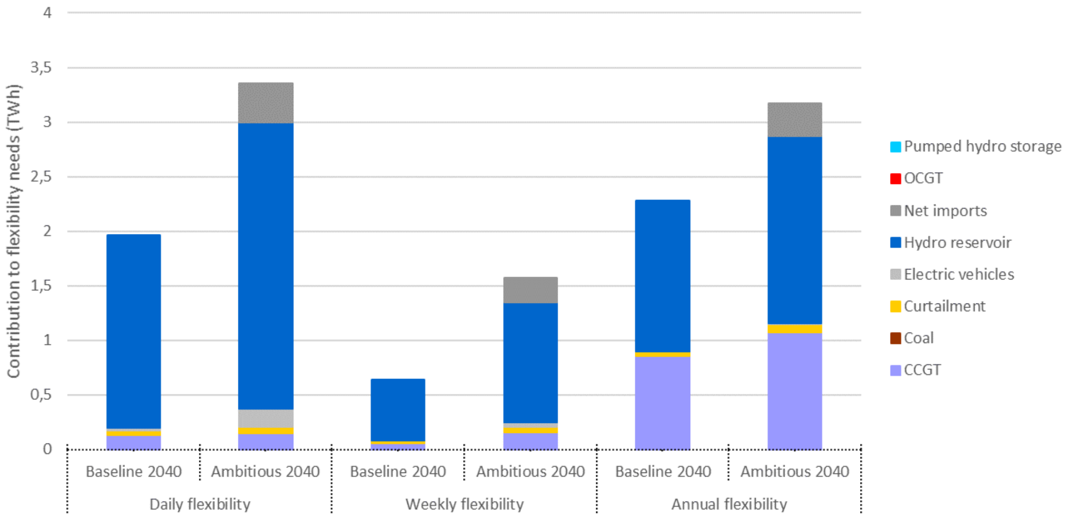

Figure 80 - Contribution to flexibility needs - Georgia

6.2.5 The role of exchanges with neighbouring countries

Figure 81 presents the import/export balance for all CPs and scenarios in 2040. They are compared to the 2030 Baseline scenario.

In the Baseline 2030 scenario, Ukraine, Bosnia and Herzegovina and Albania are net exporters (due to a surplus of production), whereas all other CPs are net importers. By 2040, most countries increase their need for imports compared to 2030. Ukraine and Bosnia and Herzegovina become net importers due to an ambitious coal phase-out and inequivalent vRES deployment to compensate this phase-out (according to the scenario assumptions). Albania is the only net exporting CP across all scenarios. Looking at the 2040 horizon only, net imports are reducing from Baseline to Ambitious scenario. The vRES deployment allows for more self-sufficiency for each country. Serbia has the largest value of necessary imports (in absolute values).

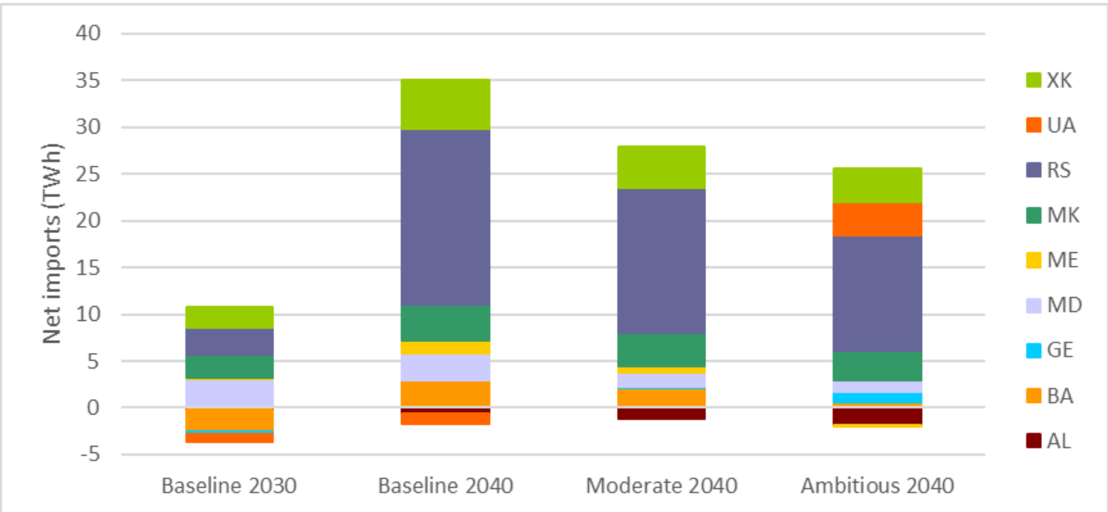

Figure 81 - Net imports in 2040 in the Energy Community

Focus on Albania

Hydropower generation in Albania represents 80% of domestic production in 2040. In the Ambitious scenario, the country features an exceed of supply which allows to provide daily and weekly flexibility to neighbours (Figure 82). Albania's hydro power fleet becomes one of the main flexibility providers for the entire WB6 region.

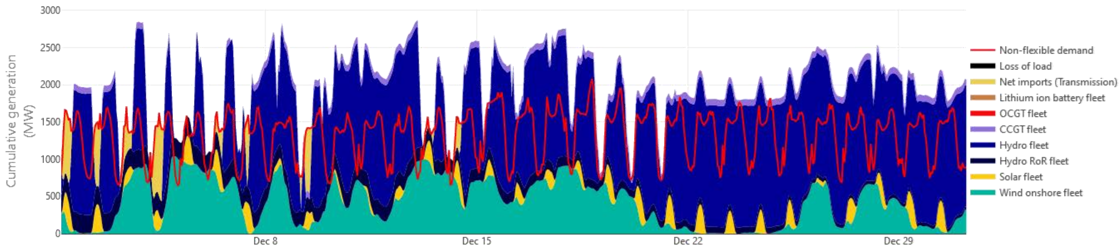

Figure 82 - Hourly cumulative generation (MW) in Albania for December, Ambitious 2040 scenario

6.2.6 CO2 emissions

By 2040, CO2 emissions are shifted from coal/lignite-based generation (Baseline scenario) to gas-based generation (Ambitious scenario).

In WB6, overall emissions are reduced from Baseline to Ambitious scenario as there is a shift from coal/lignite to renewable generation. In Serbia, even though total emissions decrease, the emissions from CCGTs increase to compensate lignite phase-out and an insufficient RES uptake (but not as much as to cancel the emission reduction gains from lower production of lignite-based power plants, see Figure 83).

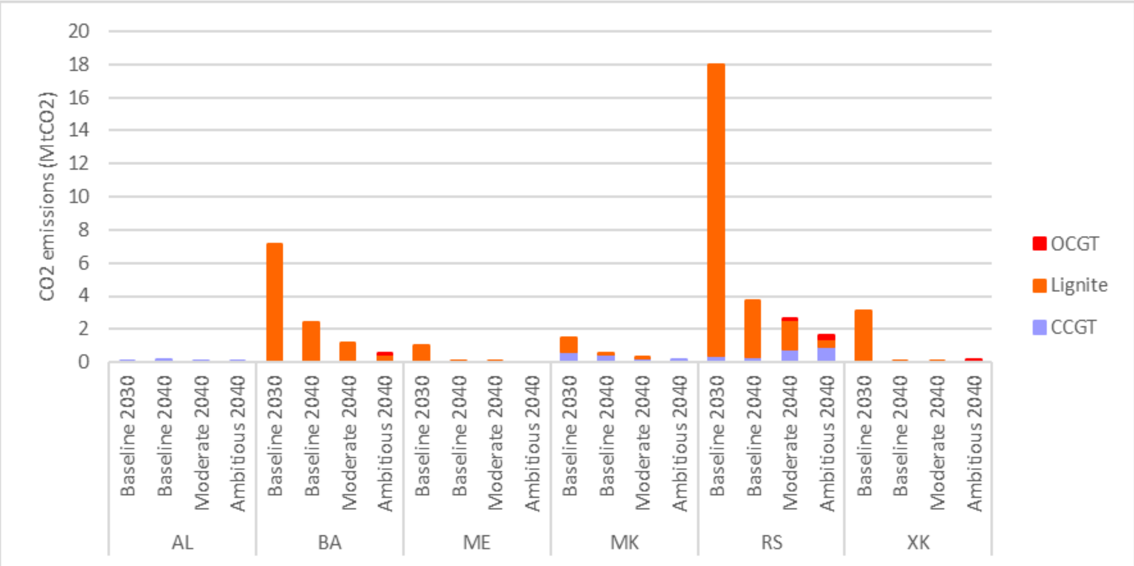

Figure 83 - CO2 Emissions in WB6

On the other hand, in the Ukraine/Moldova region (Figure 84), emissions increase between these scenarios. For Moldova, this is due to the development of additional generation capacities (CCGTs), needed to supply the local demand.

For Ukraine, the increase in CO2 emissions between Baseline and Ambitious in 2040 is due to the development of nuclear capacities in the Baseline scenario, which is not considered in the Ambitious scenario. The deployment of vRES in the Ambitious scenario is not strong enough to compensate the lack of additional nuclear capacities, thus needing to install gas-fired generation to supply demand. Thus, if

Ukraine is not able to develop additional nuclear generation power plants, a more ambitious vRES development plan should be considered to avoid a rise in CO2 emissions.

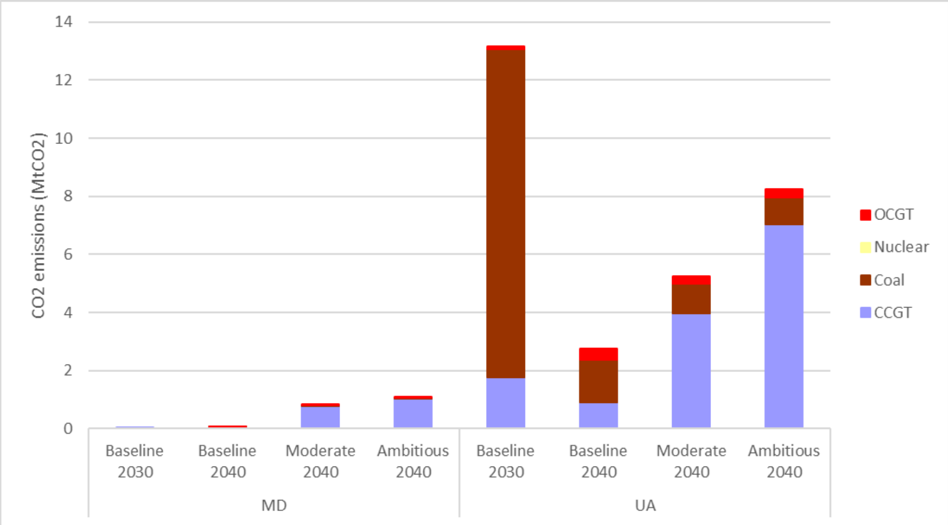

Figure 84 - CO2 Emissions in Ukraine/Moldova

In Georgia, CO2 emissions remain quite stable across all scenarios (Figure 85), even though there is a high increase in demand in the Ambitious scenario (from 14 TWh in the Baseline 2030 scenario to 24 TWh in the Ambitious 2040 scenario). The additional demand is compensated by vRES deployment and additional hydro generation. However, the flexibility of CCGT capacity remains necessary to ensure supply in winter, which results in slightly increased global emissions in the Ambitious 2040 scenario.

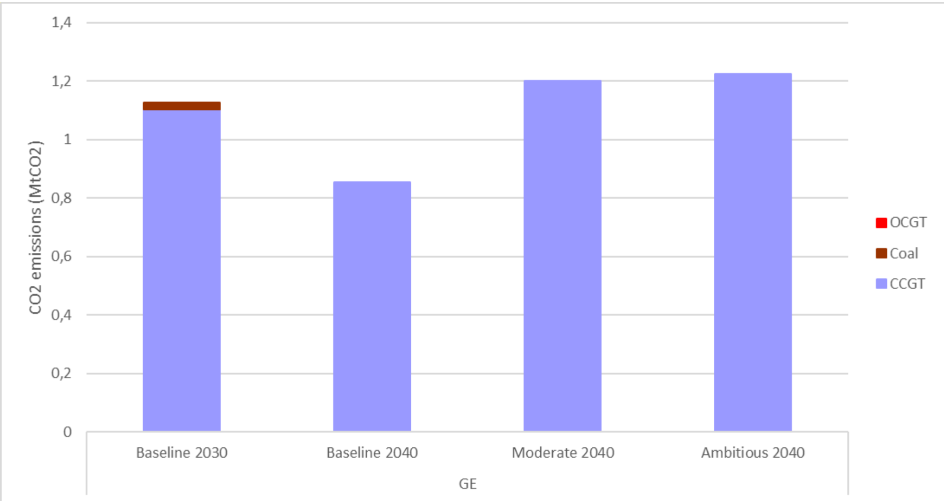

Figure 85 - CO2 emissions in Georgia

Figure 86 shows the carbon intensity of CPs in 2040. The carbon intensity is below 100 kg/MWh for all countries, except Bosnia and Herzegovina and Serbia for the Baseline scenario, and for Moldova in the Moderate and Ambitious scenarios. The increase of carbon intensity for Moldova is due to the development of CCGT generation needed to supply demand.

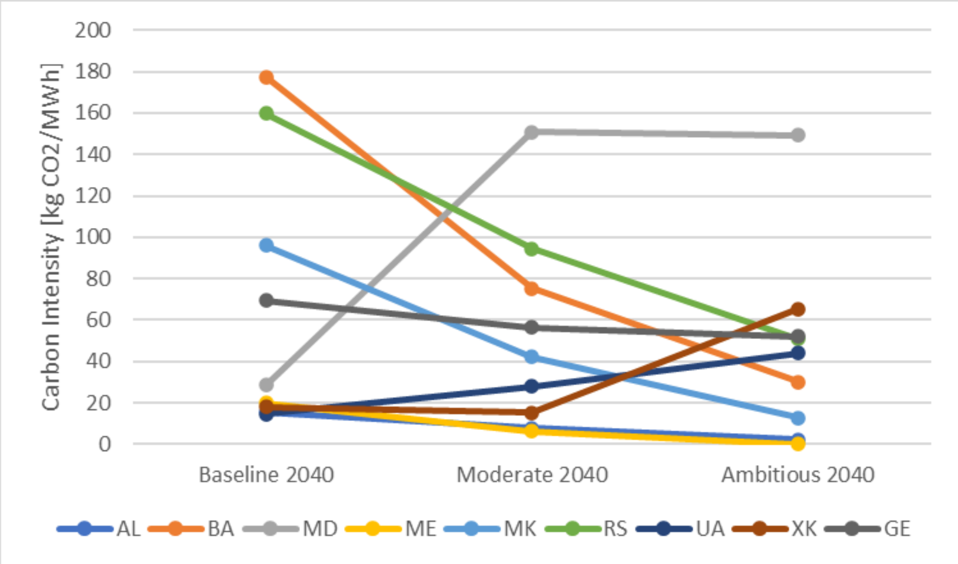

Figure 86 - Carbon intensity of national generation per CP and scenario, 2040 [kg CO2/MWh] (only direct emissions from the burning of fossil fuels)

6.2.7 Conclusions for the 2040 horizon, fragmented market scenario.

The scenarios developed in this study which consider a coal/lignite phase out in 2040 with significant investment in vRES generation (based on feedback from CPs) reveal that investments in flexibility solutions differ from one scenario to another but remain low in 2040 across all scenarios:

- ✓ Interconnection capacities are the main provider of flexibility. They facilitate the deployment of vRES by allowing to share the flexibility resources across countries, lowering the needs for additional investments. Significant flexibility is already provided through regional cooperation among WB6 countries.
- ✓ Additional storage capacities seem most relevant in countries where the RES share in the generation mix is the most significant. This is the case of batteries in Kosovo* and Montenegro, who have the highest share of vRES over installed capacities, and where batteries allow to absorb excess vRES generation to restore it to the system at a later point in time.
- ✓ CCGTs appear necessary in countries where the supply side is lacking of sufficient power generation or import capacities (which is partially driven by the coal phase-out). Peak generation capacities (OCGTs) are required only in a few cases (Serbia and Bosnia in the Ambitious scenario) to ensure the supply-demand equilibrium in selected hours of the year.

  By 2040, CO2 emission sources shift coal/lignite-based generation (Baseline scenario) to gas-based generation (Ambitious scenario).

6.3 Optimal flexibility portfolios under a Market integration scenario

This section focuses on the comparison between Fragmented Market (FM) and Market Integration (MI) scenarios, which differ by the level of net transfer capacities (NTCs) in interconnections, for the Moderate and the Ambitious scenario. The Integrated Market scenario reflects enhanced integration of regional markets, allowing 70% of cross-border interconnection capacities to be used for commercial exchanges. This section therefore analyses the optimal flexibility portfolios required in the Energy Community by the year 2040 under the two contrasting interconnection scenarios. It looks at the differences in capacity expansion, RES curtailment, congestions and CO2 emissions.

6.3.1 Flexibility needs

The Integrated market scenario allows to reduce the need for additional flexibility assets for all technologies identified in the Fragmented market configuration (CCGTs, OCGT, PHS and batteries) as depicted in Figure 87. For instance, in a Market Integration configuration, no batteries seem necessary, as the larger NTC increase the possibility for cost efficient imports and exports from neighbouring countries. This effect is more prominent for the WB6 CPs, for which increased regional cooperation (within WB6 and with neighbouring EU MSs) allows for significant reduction in investments in flexibility solutions. The impact for Ukraine is less significant, as the interconnection capacities are relatively small compared to the total installed generation capacity (in comparison to WB6).

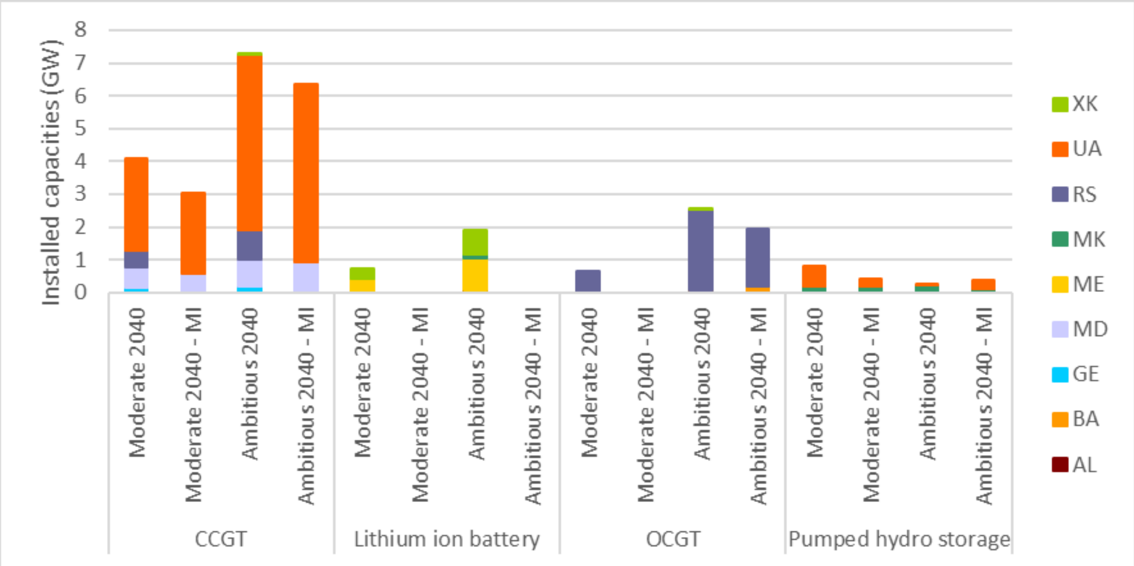

Figure 87 - Comparison of additionally installed capacities between FM and MI in 2040

Moving from the Fragment Market to the Market Integration configuration increases the share of imports among the contributors to flexibility needs and reduces CCGT contribution across all timescales (Figure 88).

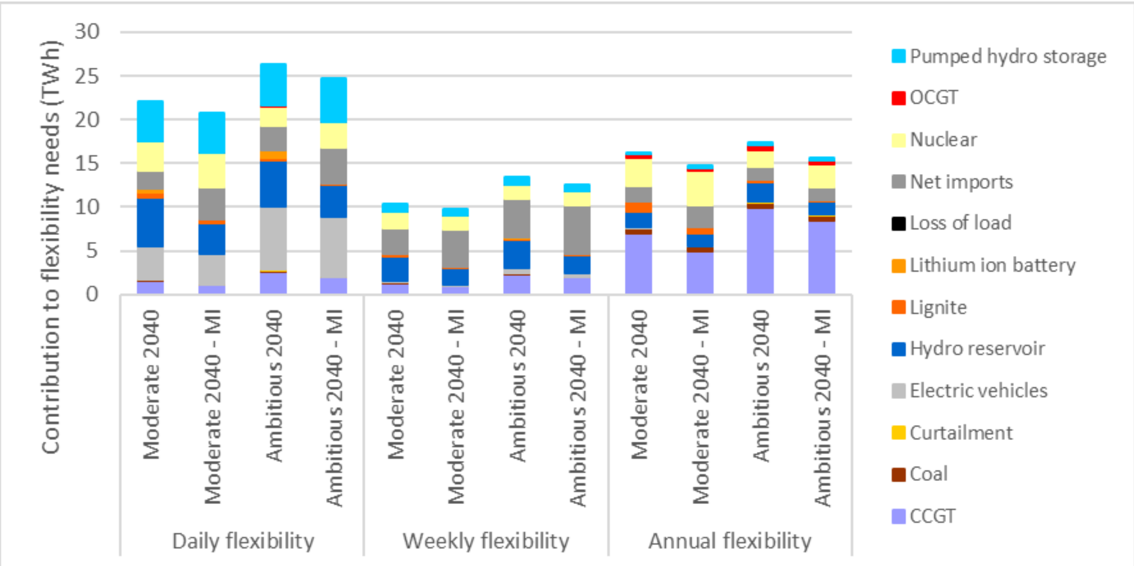

Figure 88 - Contribution to flexibility needs in 2040

6.3.2 RES integration

RES curtailment[158] within the Energy Community's CPs is quite small. It equals, in the worst case, 200 GWh (Ambitious MI 2040 scenario), which represents 0.2% of overall RES generation in CPs. It increases between 2030 and 2040, and between the Baseline and Ambitious scenarios, because of the deployment of RES.

If the geographical scope is extended to the Energy Community and its neighbouring EU Member States, curtailment decreases with the increase of NTCs. Figure 89 shows that the curtailment changes for the Contracting Parties and their neighbours (Greece, Bulgaria, Romania, Hungary, Croatia, Slovakia, Poland). In a Market Integration scenario, the overall curtailment decreases by 25%. Note that compared to the pool of considered here, the 200 GWh of curtailment of the Energy Community only represents 1% of the total curtailment observed in the countries considered.

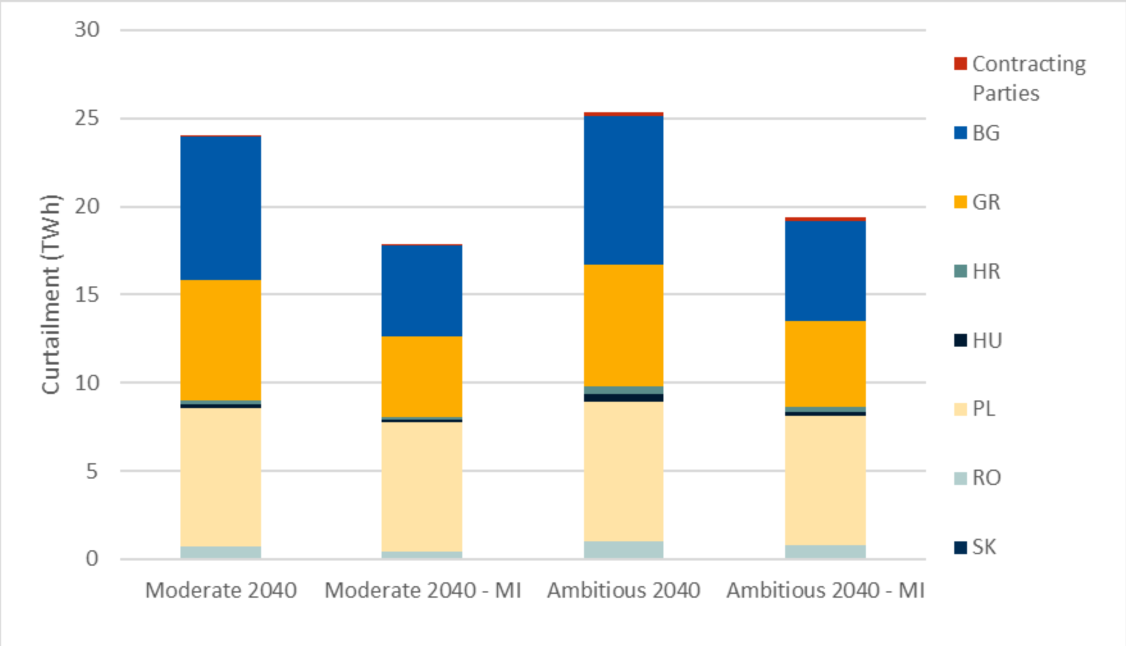

Figure 89 - RES curtailment (TWh) for the EnC CPs and neighbouring EU MSs in 2040, Fragmented Market and Market Integration (MI) scenarios

6.3.3 Congestion of interconnections

With the high share of vRES and the use of interconnections to dispatch its surplus across different countries, some interconnectors present critical levels of congestion in 2040. Figure 90 highlights the the major interconnections with WB6, which are all congested in the import direction, from Bulgaria, Greece and Romania to WB6 (benefiting of the surplus vRES generation of these CPs). In the Fragmented Market configuration, interconnections with Bulgaria are the most congested ones, with above 7 000 hours of maximum use over the year[159].

[158] Curtailment refers in the present analysis to market-based and not grid-based RES curtailment.
[159] The TYNDP 2020 Distributed Energy scenario considers the development of additional nuclear capacities in Bulgaria allowing it to export large amounts of low-cost CO2 emission-free electricity to the WB6 CPs and leading to high use of the interconnections.

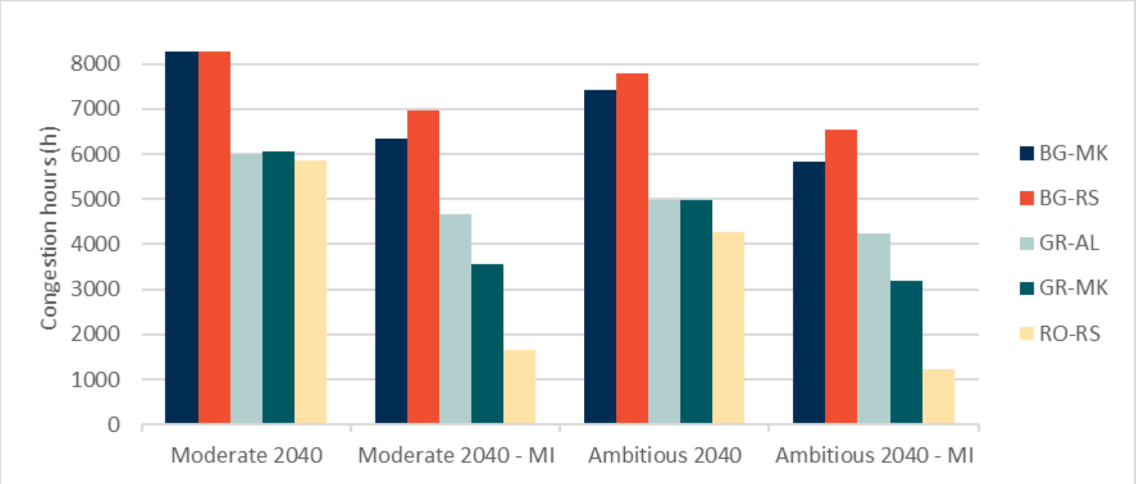

Figure 90 - Congestion hours in 2040 for specific high-use interconnections between WB6 and neighbouring EU Member States

The Market Integration configuration relieves interconnectors, decreasing congestion hours significantly for the five considered interconnections. However, some remain high, such as from Bulgaria towards North Macedonia and Serbia (around 6000 hours over the year, respectively).

Figure 91 highlights the major critically used interconnections towards Ukraine/Moldova, which are also all in the import direction, from Slovakia, Hungary and Romania towards Ukraine and Moldova. Main congested lines reach a maximum of 5 000 congestion hours over the year which is less significant than in the WB6 regions. The Market Integration situation also reduce significantly overall congestions. Note that the Poland>Ukraine NTC is considered as of 0 MW in the Fragmented Market scenarios[160] (while 297 MW in the MI scenarios).

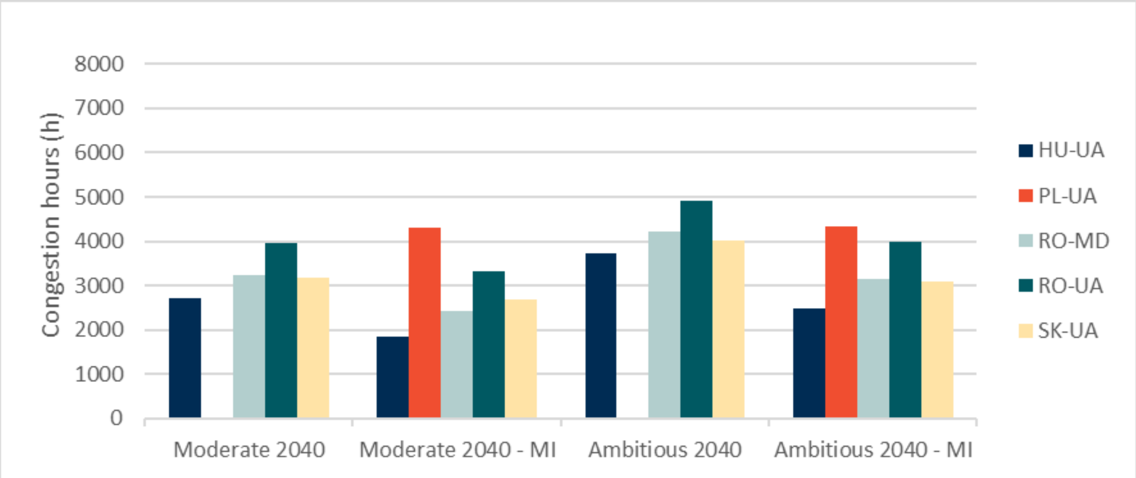

Figure 91 - Congestions hours in 2040 for specific high use interconnections between Ukraine/Moldova and neighbouring EU MS

Figure 92 shows interconnection use between CPs. They are governed by Albania's exports to Montenegro and Serbia's and North Macedonia's exports to Kosovo*, reflecting the need for generation and flexibility capacities in Kosovo*. Market Integration also reduces congestion hours within the WB6.

[160] Hypothesis of the construction of scenarios based on feedback from the Energy Community Secretariat.

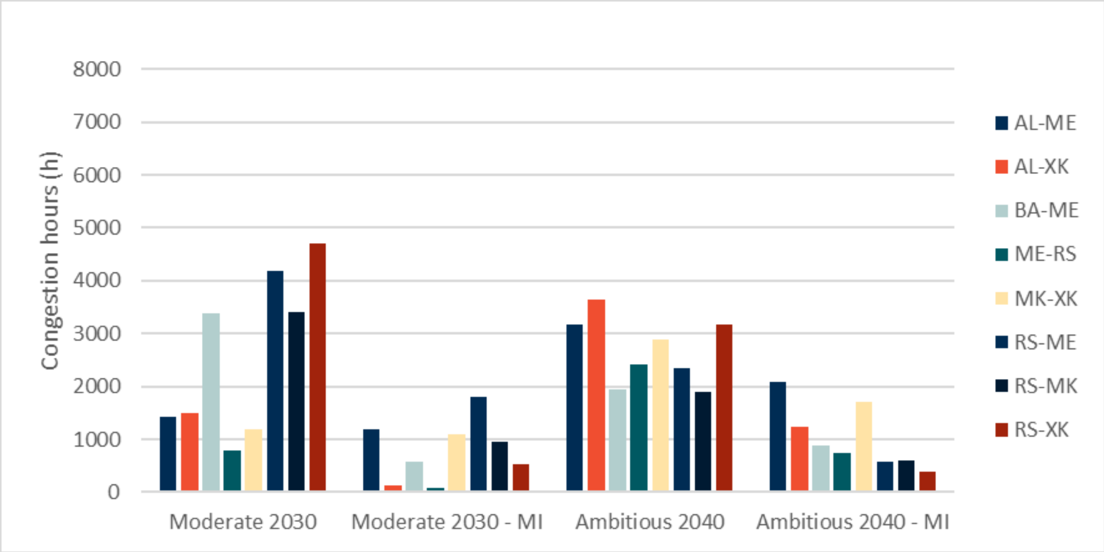

Figure 92 - Congestions hours in 2040 for specific high use interconnections inside the Energy Community

Note that the Ukraine/Moldova interconnection presents low congestion (<200h in all scenarios), for two reasons: a higher share of imports comes from RO and a high interconnection capacity.

6.3.4 CO2 emissions

The reduction of RES curtailment observed in the Market integration scenario, which is absorbed by CPs, allows for a decrease of fossil fuel generation in the EnC and thereby a reduction in CO2 emissions. The most important reduction in CO2 emissions comes from a reduction of gas supply, mainly in UA. This accounts for a reduction of 27% in the Moderate scenario and 21% for the Ambitious scenario, as can be seen in Figure 93.

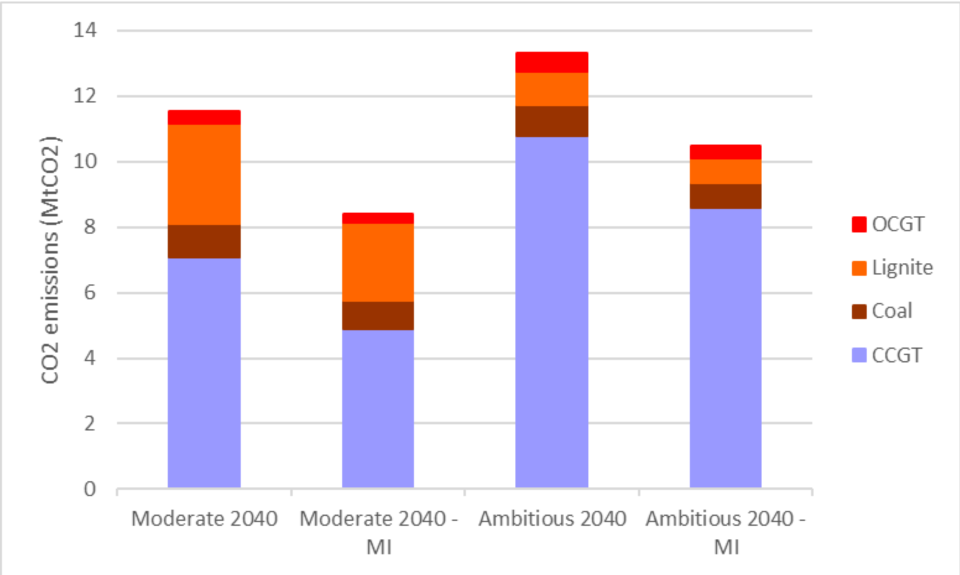

Figure 93 - CO2 emissions (MtCO2) in 2040 between FM and MI scenario

6.3.5 Conclusions on the benefits of regional market integration

This section analysed the benefits of increased regional market integration among CPs connected to the CESA. This was modelled by an increase of Net Transfer Capacities (NTC) of interconnectors between CPs and with EU MSs, going from 17.5 GW in the Fragmented Market case to over 38.1 GW in the Market Integration scenario[161].

Increased market integration allows to reduce the investments of additional flexibility assets in the EnC CPs by sharing flexibility resources among CPs and with EU MSs. It also leads to a significant reduction in RES curtailment in neighbouring EU MSs by over 6 TWh which are consumed by CPs, decreasing the generation of fossil fuel generation (mainly by CCGTs) and consequently their CO2 emissions.

Congestion hours are lowered but remain high for many interconnectors, indicating room for an even more important interconnector extension in some corridors.

[161] Sum across all interconnectors of the 8 CPs connected to the CESA,

7 Conclusions and outlook

This study analyses the existing flexibility assets which are remaining by 2030/2040 and additional investments required in the Energy Community to facilitate the integration of rising shares of variable renewable power generation and the phase-out of coal and lignite-fired generation in selected CPs. The analysis builds upon three scenarios with varying level of deployment of renewables and two scenarios on the level of cross-border interconnection. Three main conclusions can be drawn from the model-based analysis of the different scenarios:

- ✓ There is no need for investments in additional flexibility capacities by 2030. The existing capacities that provide system flexibilities, namely cross-border interconnections (enabling increasing imports), gas-fuelled power plants and storage assets (including reservoir hydro), but also other thermal plants can cope with the rising flexibility needs related to an increasing degree of RES deployment, even in the Ambitious scenario. In CPs with coal and lignite capacities, they continue to represent a relevant share in total power generation and hydropower or interconnections provide additional flexibility (even in the Fragmented market scenario, which considers limited cross-border interconnection).

- ✓ Necessary investments in new flexible solutions are low in 2040, despite the coal and lignite phase-out envisioned in almost all CPs. Interconnection capacities are the main provider of flexibility at the CP level, allowing to mutualise flexibility resources among CPs and with EU MSs. Storage capacities are relevant in CPs where the RES shares are highest (Montenegro, Kosovo* and North Macedonia) while gas power generation assets are particularly necessary in CPs who lack cost-competitive generation capacities to meet the national demand (Ukraine, Moldova, Serbia by 2040).

- ✓ Market integration of regional power systems decreases the need for flexibility from storage and thermal generation, and drives down CO2 emissions. Such regional cooperation facilitates RES integration at lower costs and reduces congestions between Contracting Parties and with neighbouring interconnected countries.

From the extensive quantitative simulations, a set of additional, more detailed insights can be drawn:

- ✓ Flexibility needs increase in high-RES integration scenarios, however not uniformly across time scales. Daily flexibility needs experience the higher increase, driven mainly by daily generation patterns of solar PV, followed by weekly needs, as weather effects can create multiday-long periods of high wind or PV generation. Annual needs remain relatively stable, as PV and wind have complementary seasonal generation patterns.
- ✓ The uneven increase in flexibility across timescales is important, as some technologies can provide flexibility at specific timescales. In particular, the increase of daily and weekly flexibility will require short-to medium-term flexibility assets, including storage, OCGT and demand response assets such as lithium-ion batteries, electric vehicles and PHS. Annual flexibility is supplied mainly by generation assets, such as thermal power plants (coal, lignite, CCGT and nuclear) and hydro reservoirs with large scale (seasonal) storage capacities.
- ✓ WB6 flexibility needs arise from large-scale vRES integration and lignite phase-out. Most flexibility is delivered by hydro power plants, both reservoir and PHS, and from interconnection capacities, both from within the WB6 region (highlighting the importance of regional market

integration) and from EU, at all timescales. In particular, Albania's hydro fleet acts as a flexibility provider for the whole region. Investments in the region relate mostly to peak power plants (OCGTs) and batteries at the 2040 horizon.

- ✓ The Ukraine/Moldova region will see a significant share of its generation fleet decommissioned by 2040 (over 20 GW of coal and gas power plants). This will require investments in generation capacities, such as vRES, nuclear (Baseline scenario in UA), or new CCGTs if the RES capacities are not sufficient (Ambitious scenario). The Ukrainian nuclear fleet provides a large share of flexibility for the region, at all timescales, which is complemented mainly by hydro and PHS. CCGTs are mostly used to provide annual flexibility, generating during low hydro/RES generation seasons. In comparison to WB6, interconnection plays a minor role as flexibility source.
- ✓ Georgia, similar to Albania, has a power system dominated by hydro power plants, featuring a significant flexibility potential. Integration of vRES does not require investments in new flexibility assets. However, significant variability from seasonal hydro generation patterns already exists, and gas generation (CCGTs) is needed during low hydro generation seasons, contributing to annual flexibility needs.
- ✓ Electric vehicles can be a key flexibility asset for daily needs, if smart charging and V2G are developed. In this study, Ukraine was considered having a higher EV adoption rate, reaching 4 million EVs by 2040 (Ambitious scenario). In this scenario, the contribution of EVs arise to over 40% of the CPs' daily flexibility needs, lowering the investments in alternative assets and facilitating renewables integration. The development of smart charging and V2G can also provide other flexibility services which are not considered in this study (participation to reserves, local congestion management, self-consumption), and can enhance the business case of smart e-mobility.
- ✓ Considered CO_2 prices (60 €/ton in 2030 and 100€/ton 2040) are sufficiently high to significantly reduce coal and lignite generation in the EnC contracting parties. Free carbon allowances allow to maintain CO_2-intensive generation in the WB6 (lignite) and Ukraine (coal), and act as some kind of upper limit to each CP's CO_2 emissions. The considered CO_2 prices may appear as a lower limit for the 2030 and 2040 horizons, considering current EU-ETS prices already above 60 €/ton. This would mean that CO_2-intensive generation is unlikely to continue in the absence of free carbon allowances.

This study is based on a set of assumptions that are presented in this report. They condition the modelling results and should be kept in mind when contextualising the latter. The main limitations of the modelling approach and options to overcome these in future assessments are summarised as follows:

- ✓ The optimisation of the investment flexibility portfolio was simulated considering only a single weather year, corresponding to average conditions. The implications are two-fold:
  - o Extreme weather conditions which impact vRES generation and thus imply different flexibility needs are neglected. This could result in an underestimation of the need for storages and peak generation capacities.
  - o Some Contracting Parties are heavily dependent on hydropower which can have an important variability between years and could be impacted by climate change in the long-run. In case of a dry weather year, additional flexibility capacities, notably (gas) back up generation, might be needed.

  Considering additional weather years, potentially factoring the impacts of climate change, could provide a more robust assessment of required capacity investments.

- ✓ The hydropower modelling is simplified due to a lack of data (power plants aggregation, no consideration of cascade effects, no consideration of minimum generation levels representing environmental constraints for instance), which might overestimate the flexibility of hydropower assets. This may have an impact on several CPs, but in particular on the results for Albania and Georgia where hydropower accounts for more than 80% in power generation depending on the horizon and scenario.
  If more detailed data would be made available, the hydro-modelling approach could be better calibrated and fine-tuned to properly reflect the national specificities in hydro-based power generation.

- ✓ The optimisation was computed with an hourly and national granularity. While this represents already a very detailed approach, this cannot take into account some phenomena, which can require specific flexibility solutions. These phenomena include:
  - dynamic stability, inertia or balancing reserves and energy requirements
  - constraints emerging at the transmission or distribution grid level, in particular with respect to congestions

  If sub-hourly or sub-national data would be available, the modelling approach could be further refined.

- ✓ The results are dependent on (cost) hypotheses. Especially the CAPEX of lithium-ion batteries is subject to high uncertainty, varying across sources and evolving quite rapidly in time.
  A set of sensitivity assessments, testing different parameter variations (in particular with respect to cost assumptions) would allow to further strengthen the results and identify tipping points in the optimisation results if there are any.

- ✓ The role of demand side flexibility was only partially addressed by explicitly representing smart charging and V2G of EVs. Heat pumps, electrolysers, but also industrial and even residential/commercial consumers (e.g., refrigeration) actually also represent a source of flexibility (depending on their level of penetration and related electricity demand volumes).
  Additional data and projections would allow for a more holistic representation of demand-side related flexibility.

8 Annex A: Detailed assumptions and results for all Contracting Parties

8.1 Albania

By default, the market scenario considered is the Fragmented Market scenario.

8.1.1 Scenario description

Evolution of demand

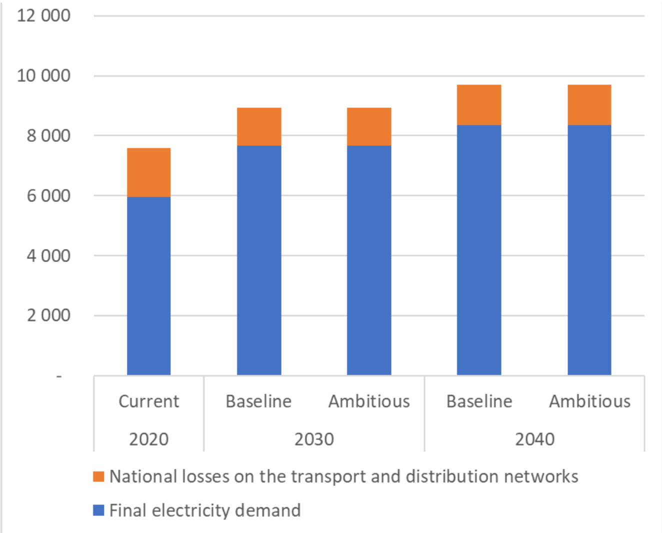

Figure 94 - Demand (GWh) in the different horizons and scenarios, Albania

Evolution of supply

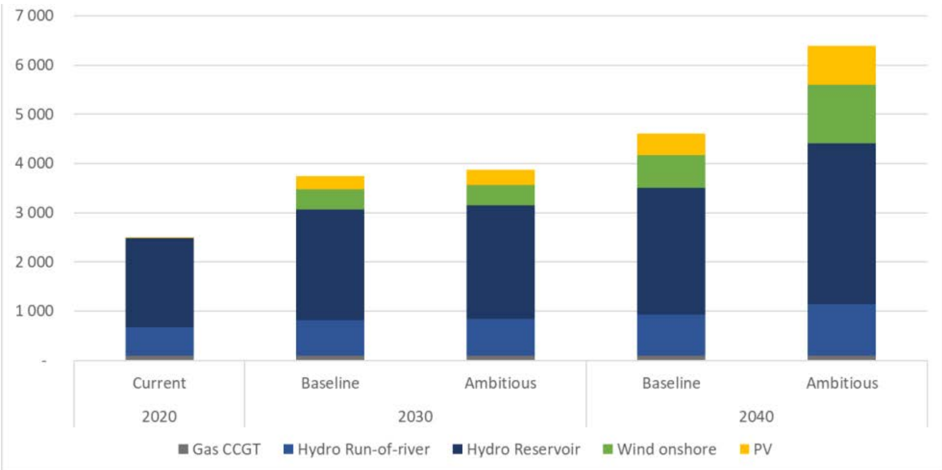

Figure 95 - Installed capacity (MW) in the different horizons and scenarios, Albania

Evolution of interconnections

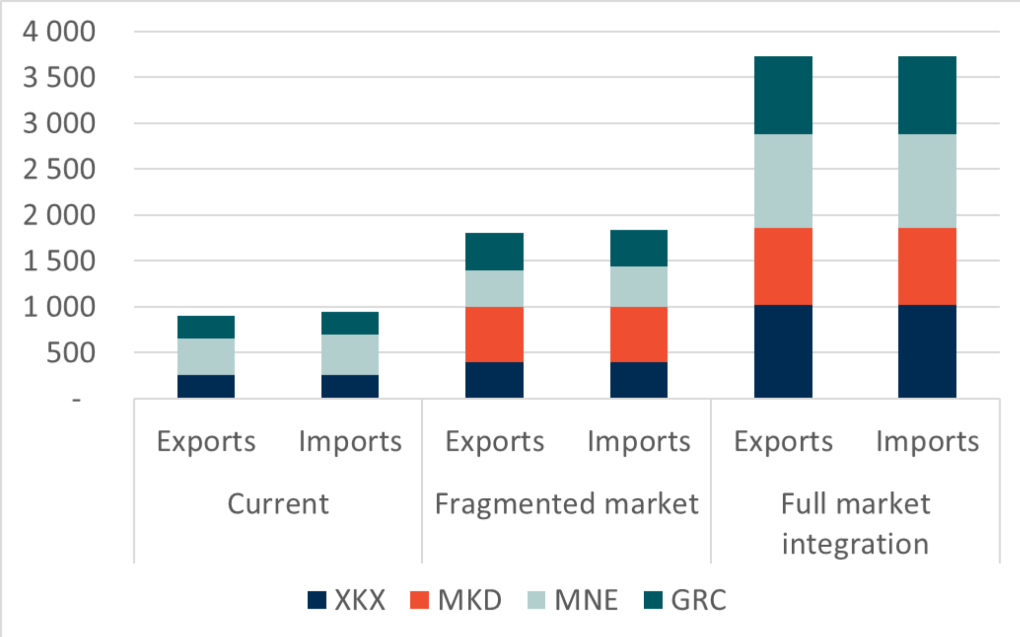

Figure 96 - NTC capacities (MW), Albania

Evolution of Flexibility needs

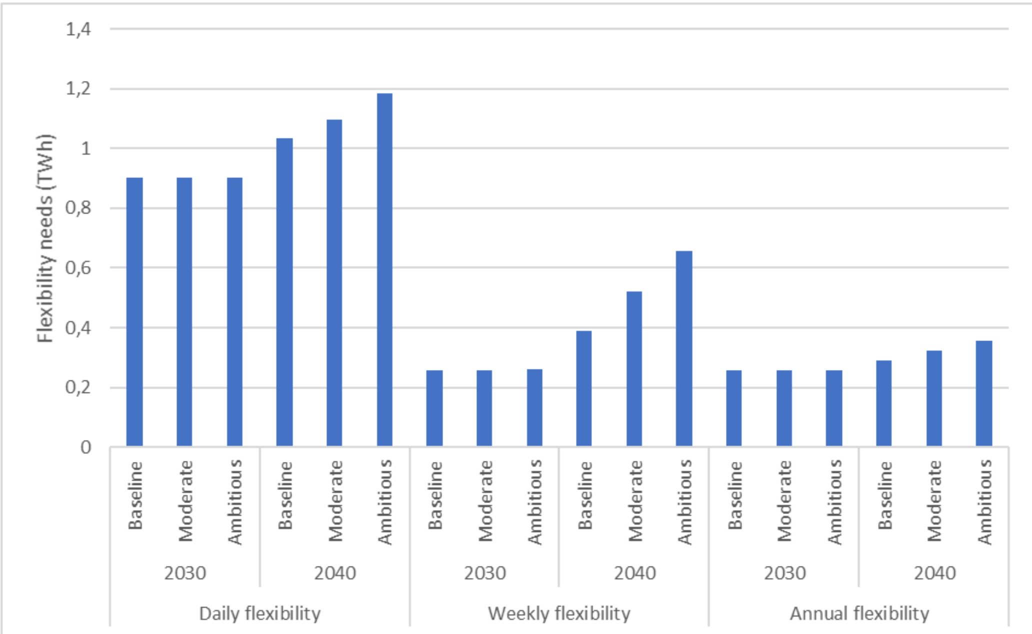

Figure 97 - Flexibility needs for 2030 and 2040, Albania

8.1.2 Generation and flexibility supply by source

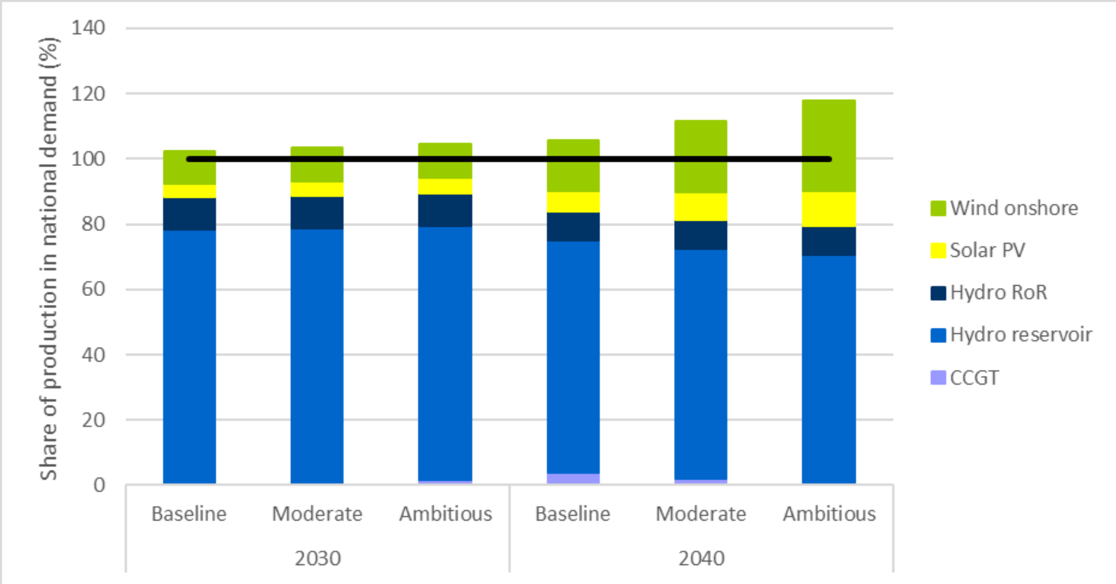

Figure 98 - Share of production in national demand (%), Albania

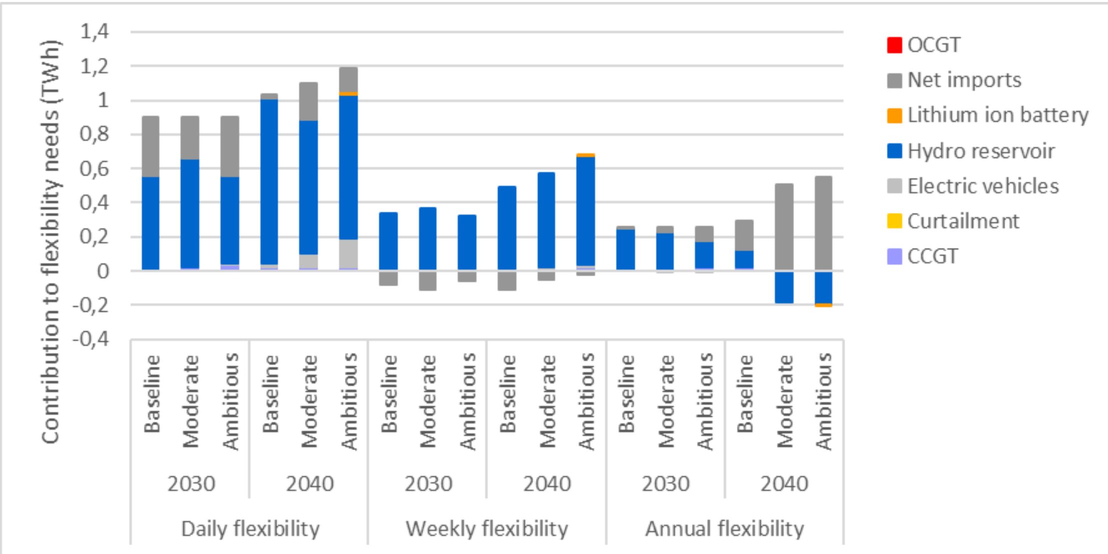

Figure 99 - Contribution to flexibility needs (TWh), Albania

8.1.3 Capacity expansion results

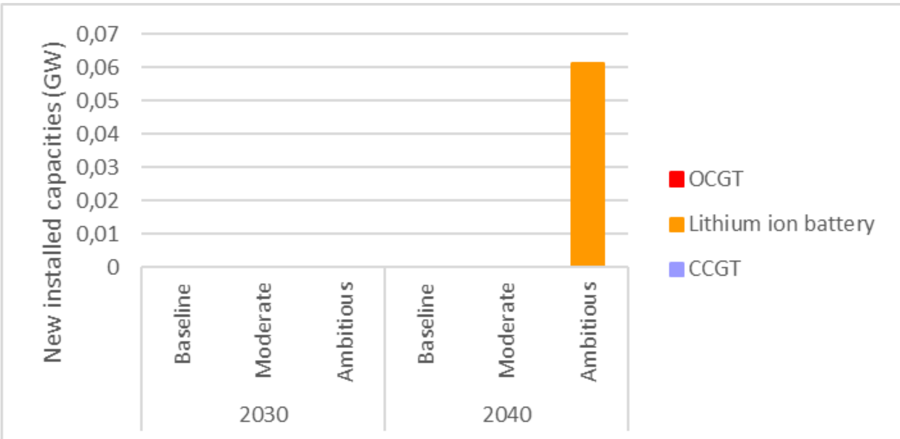

Figure 100 - Capacity expansion (MW), Albania

8.1.4 CO2 emissions

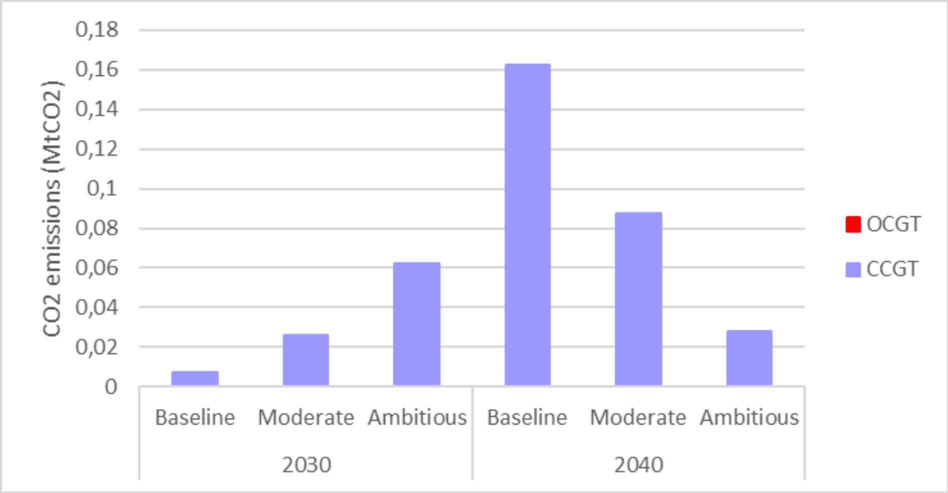

Figure 101 - CO2 emissions (MtCO2), Albania

8.1.5 Cumulative generation

Summer week

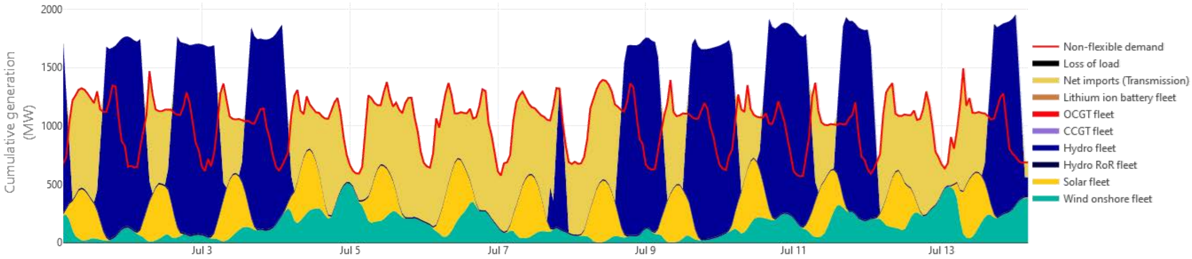

Figure 102 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Albania

Winter week

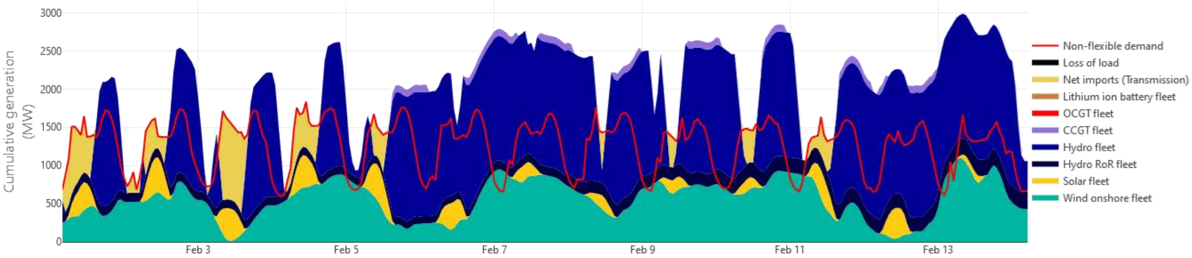

Figure 103 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Albania

8.2 Bosnia and Herzegovina

By default, the Fragmented Market scenario is the considered market scenario.

8.2.1 Scenario description

Evolution of demand

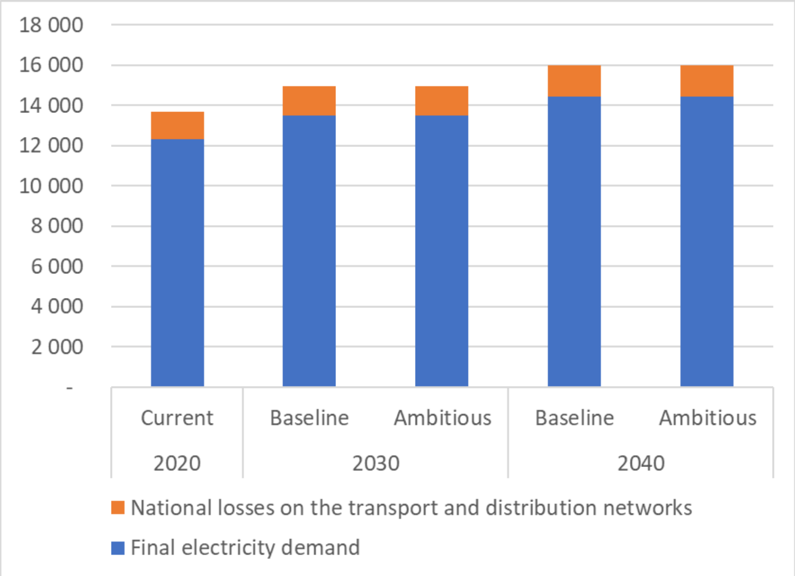

Figure 104 - Demand (GWh) in the different horizons and scenarios, Bosnia and Herzegovina

Evolution of supply

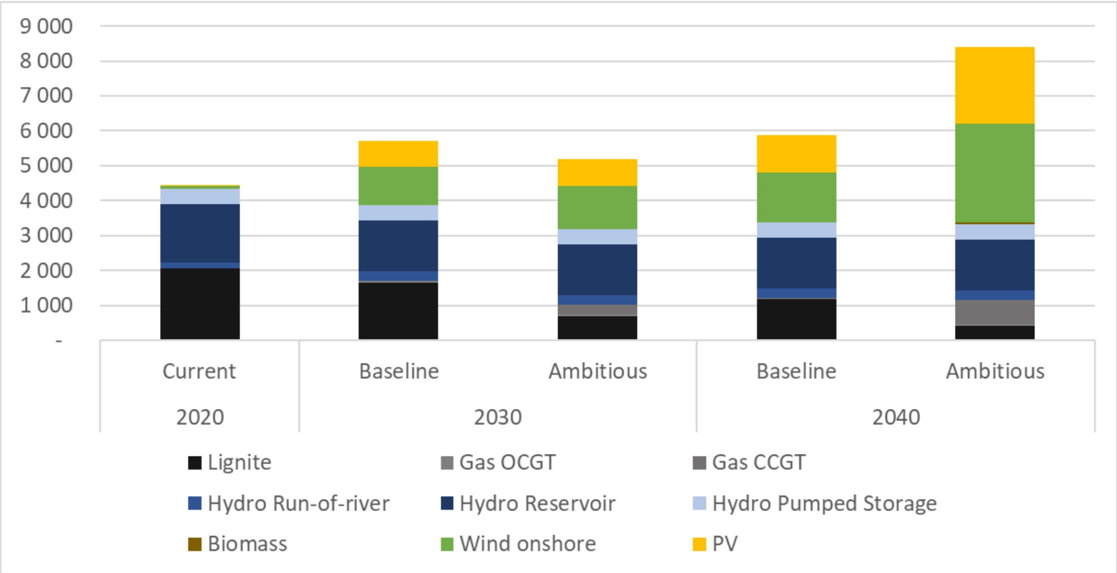

Figure 105 - Installed capacity (MW) in the different horizons and scenarios, Bosnia and Herzegovina

Evolution of interconnections

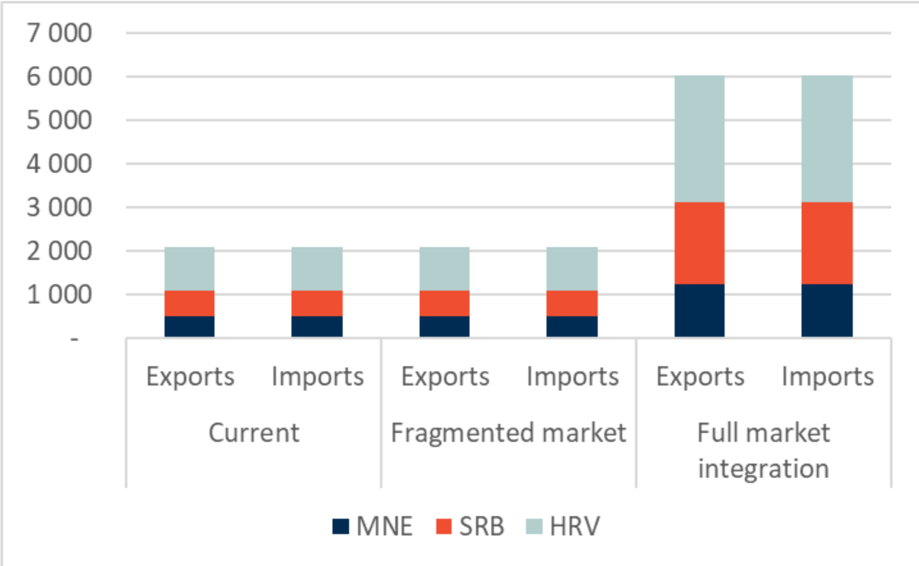

Figure 106 - NTC capacities (MW), Bosnia and Herzegovina

Evolution of flexibility needs

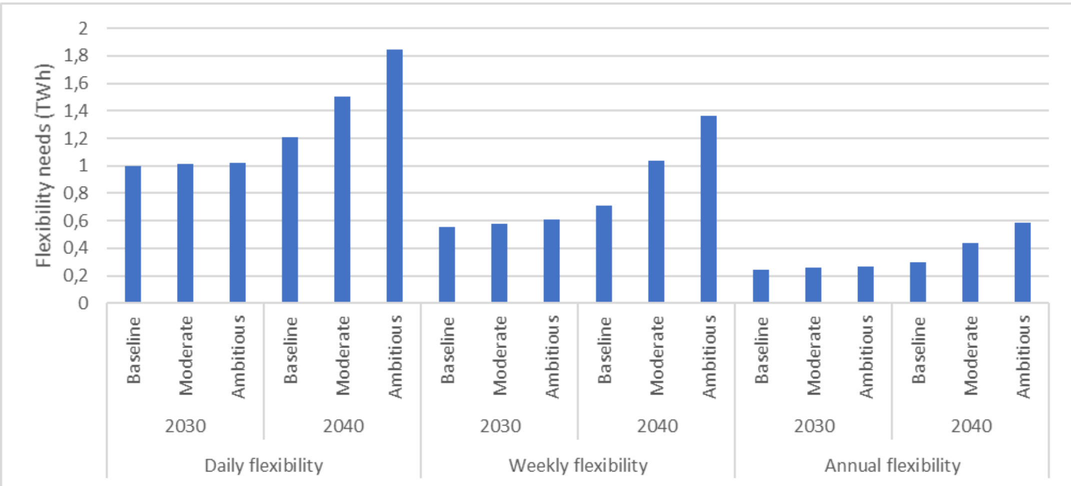

Figure 107 - Flexibility needs for 2030 and 2040, Bosnia and Herzegovina

8.2.2 Generation and flexibility supply by source

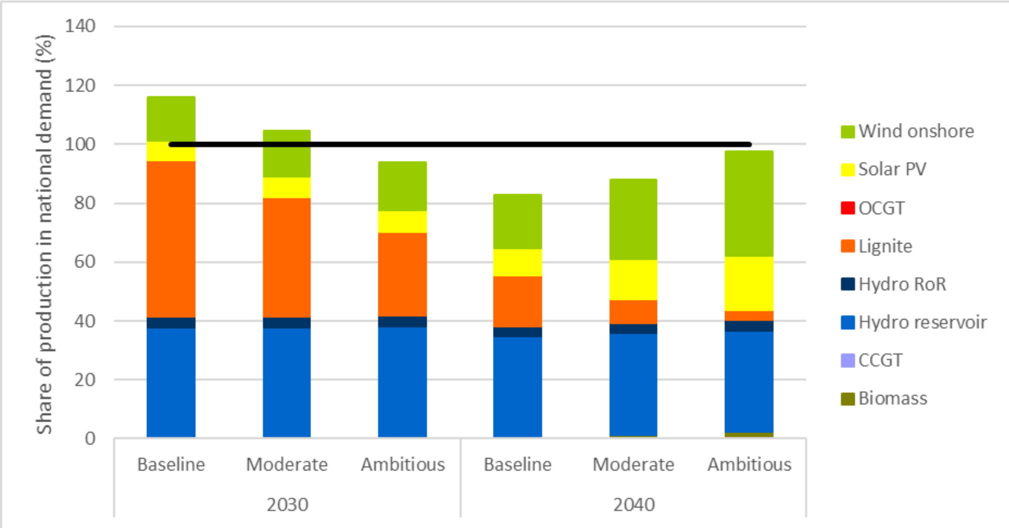

Figure 108 - Share of production in national demand (%), Bosnia and Herzegovina

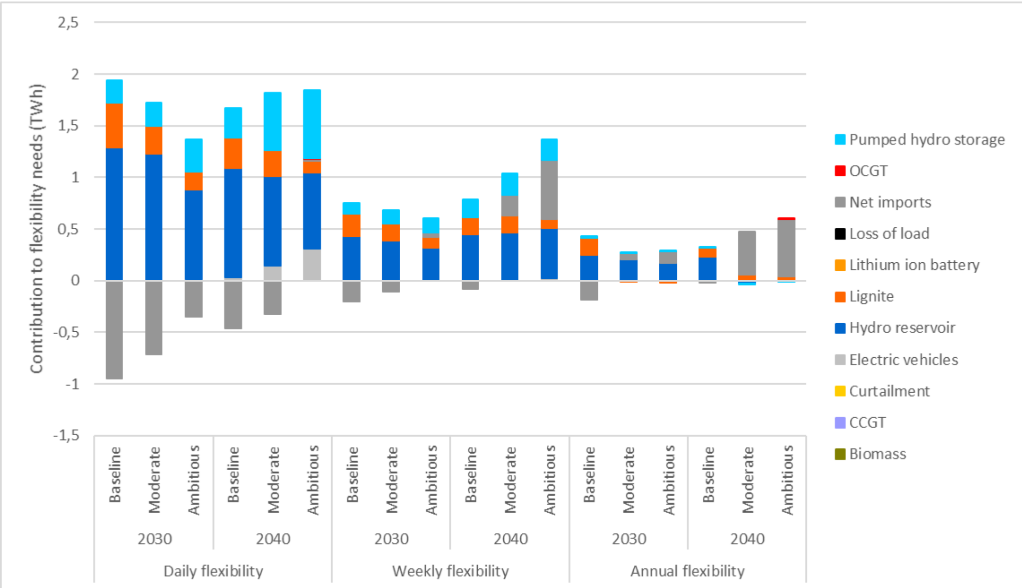

Figure 109 - Contribution to flexibility needs (TWh), Bosnia and Herzegovina

8.2.3 Capacity expansion results

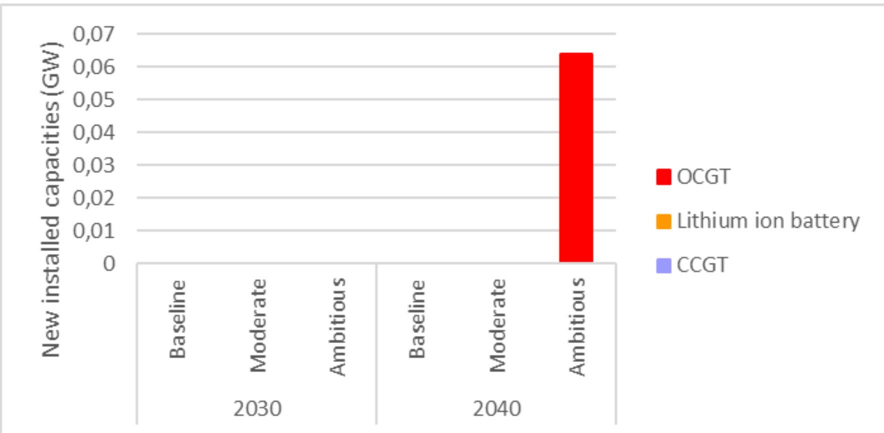

Figure 110 - Capacity expansion (GW), Bosnia and Herzegovina

8.2.4 CO2 emissions

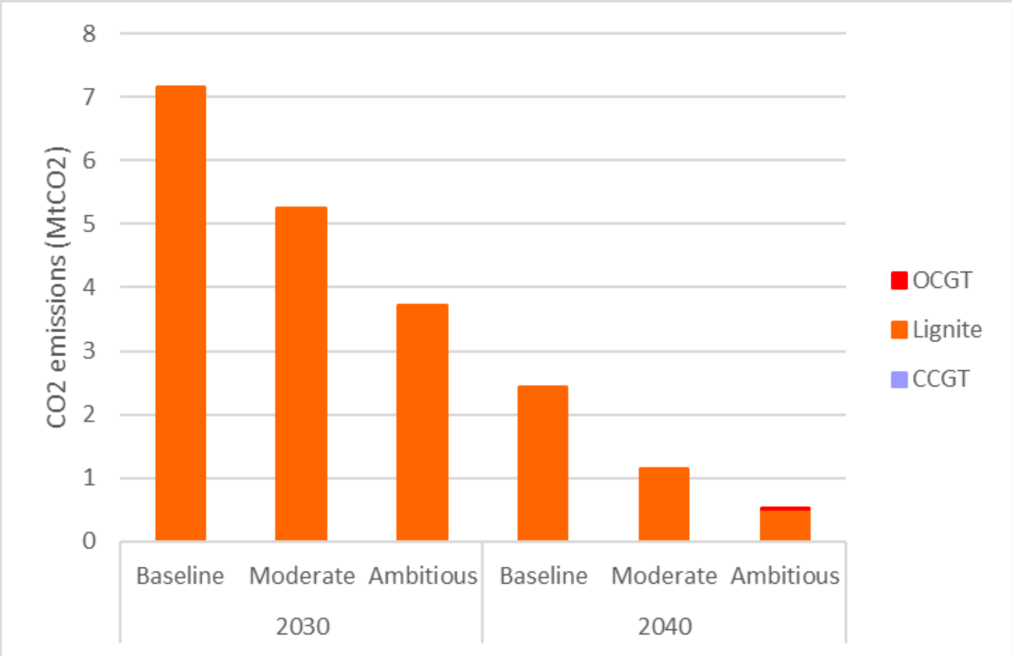

Figure 111 - CO2 emissions (MtCO2), Bosnia and Herzegovina

8.2.5 Cumulative generation

Summer week

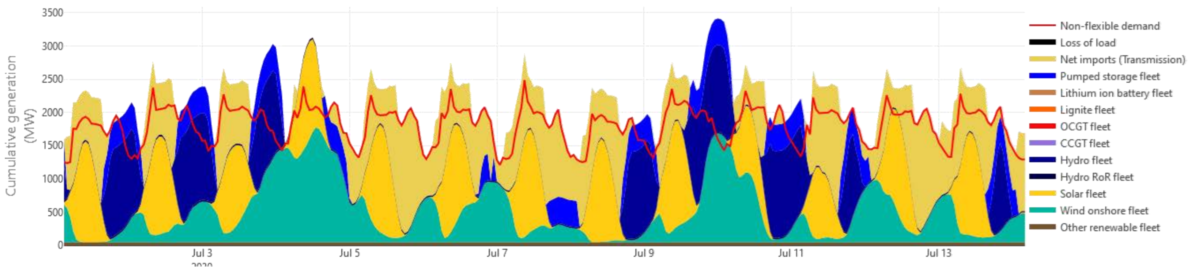

Figure 112 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Bosnia and Herzegovina

Winter week

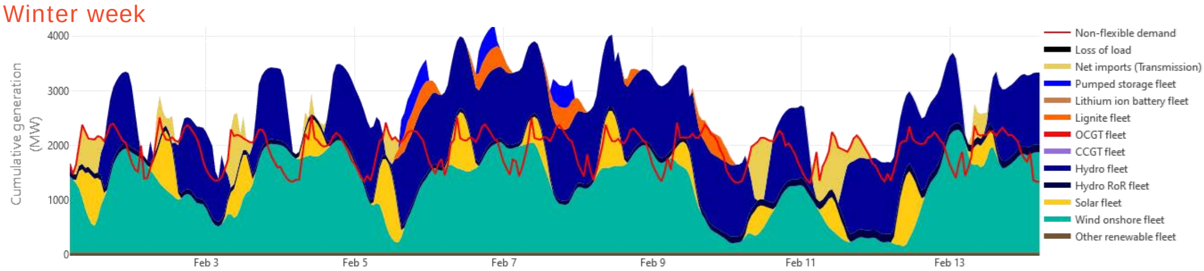

Figure 113 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Bosnia and Herzegovina

8.3 Georgia

8.3.1 Scenario description

Evolution of demand

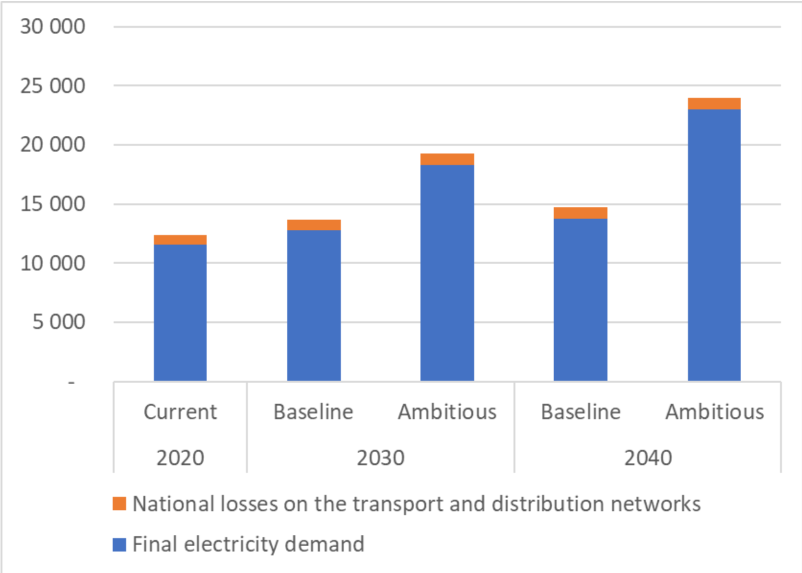

Figure 114 - Demand (GWh) in the different horizons and scenarios, Georgia

Evolution of supply

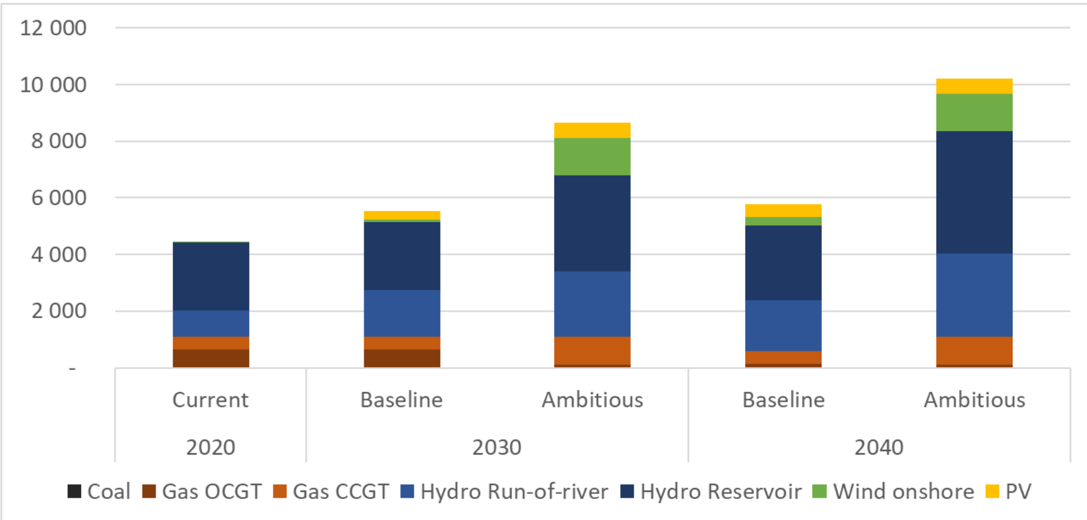

Figure 115 - Installed capacity (MW) in the different horizons and scenarios, Georgia

Evolution of interconnections

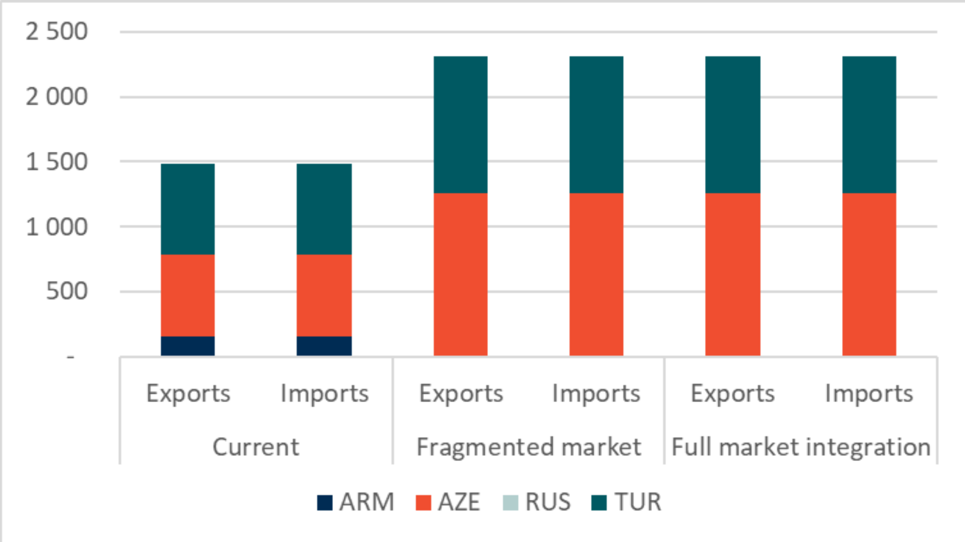

Figure 116 - NTC capacities (MW), Georgia

Evolution of flexibility needs

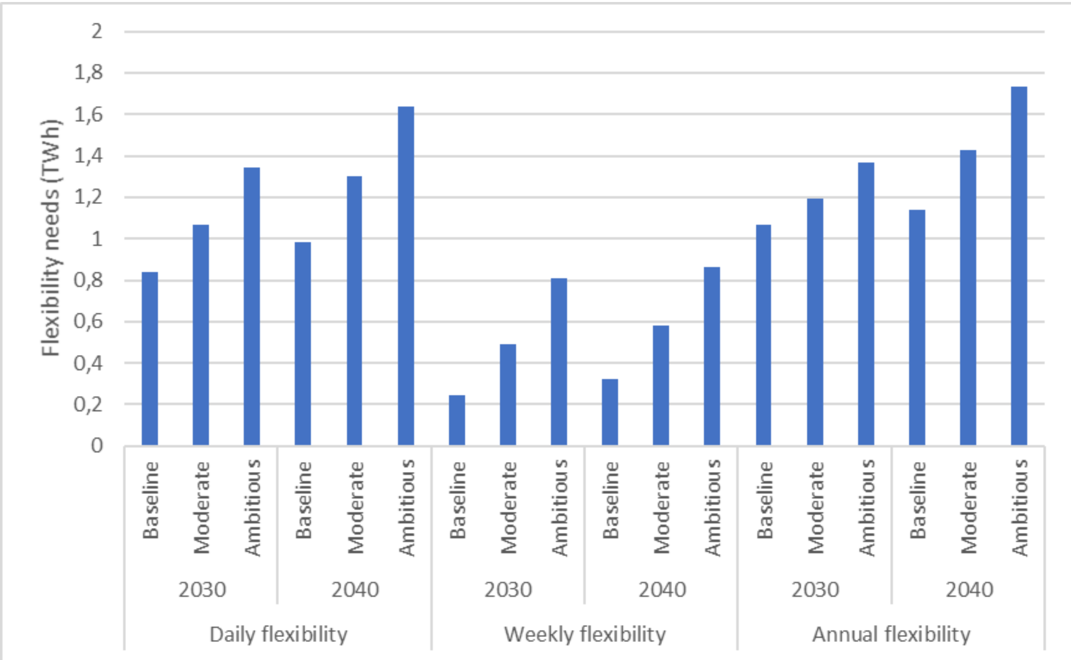

Figure 117 - Flexibility needs for 2030 and 2040, Georgia

8.3.2 Generation and flexibility supply by source

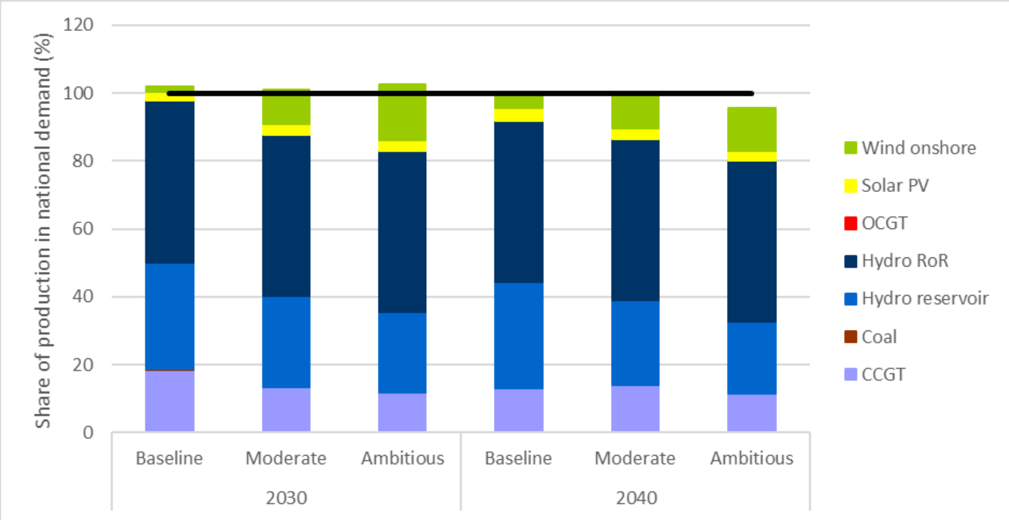

Figure 118 - Share of production in national demand (%), Georgia

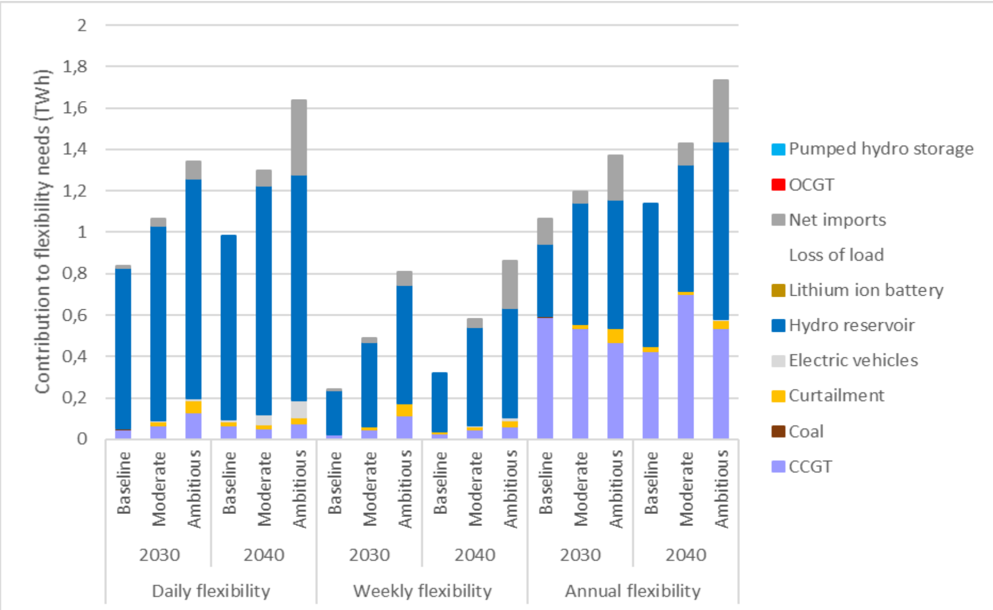

Figure 119 - Contribution to flexibility needs (TWh) , Georgia

8.3.3 Capacity expansion results

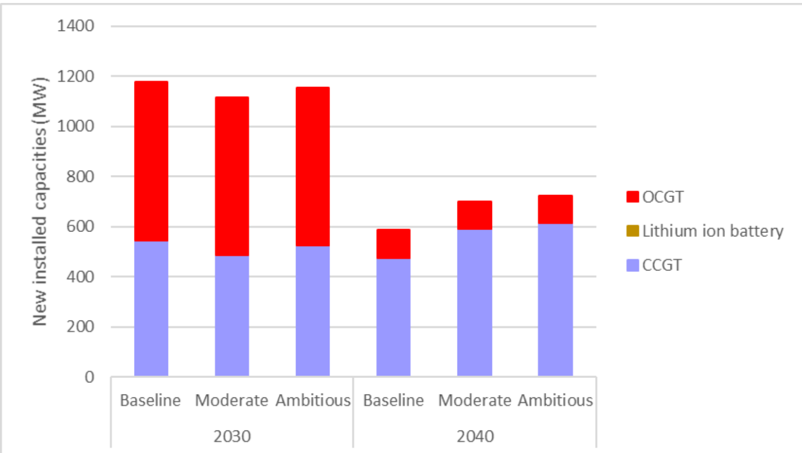

Figure 120 - Capacity expansion (GW), Georgia

8.3.4 CO2 emissions

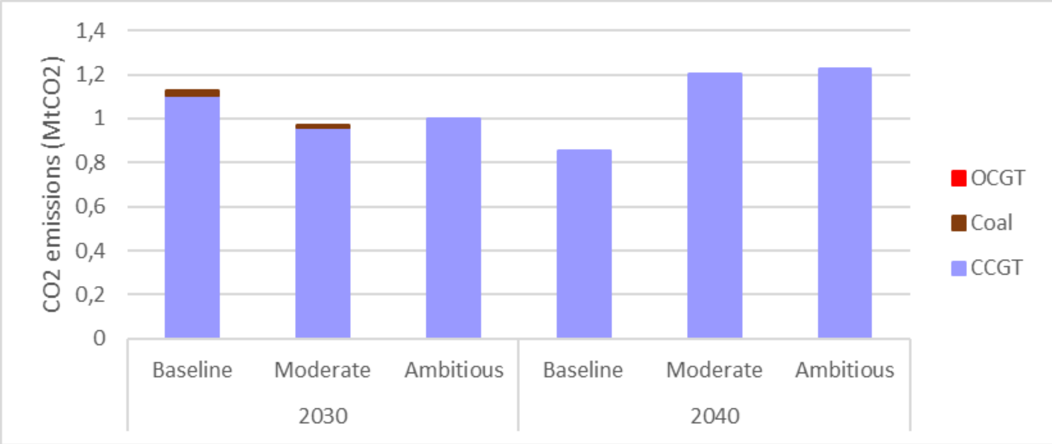

Figure 121 - CO2 emissions (MtCO2), Georgia

8.3.5 Cumulative generation

Summer week

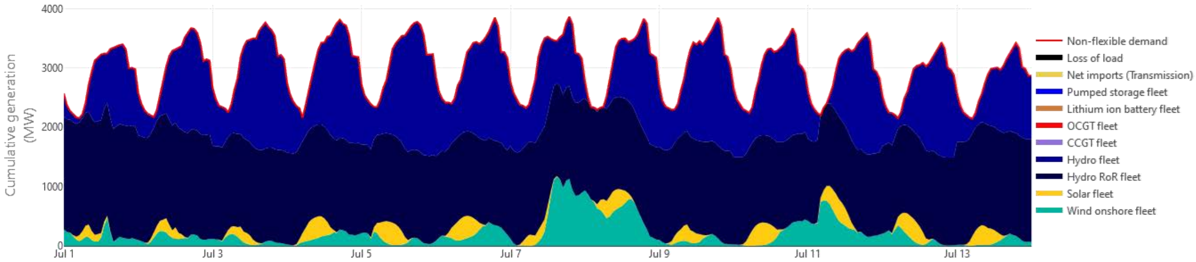

Figure 122 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Georgia

Winter week

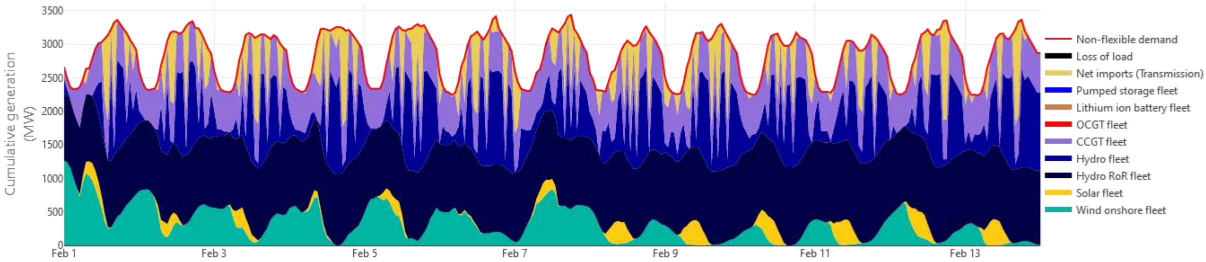

Figure 123 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Georgia

8.4 Kosovo*

By default, the market scenario considered is the Fragmented Market scenario.

8.4.1 Scenario description

Evolution of demand

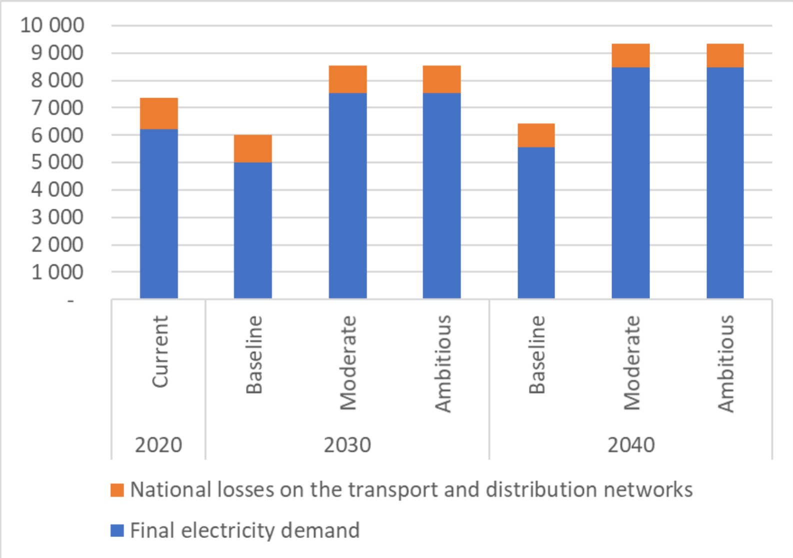

Figure 124 - Demand (GWh) in the different horizons and scenarios, Kosovo*

Evolution of supply

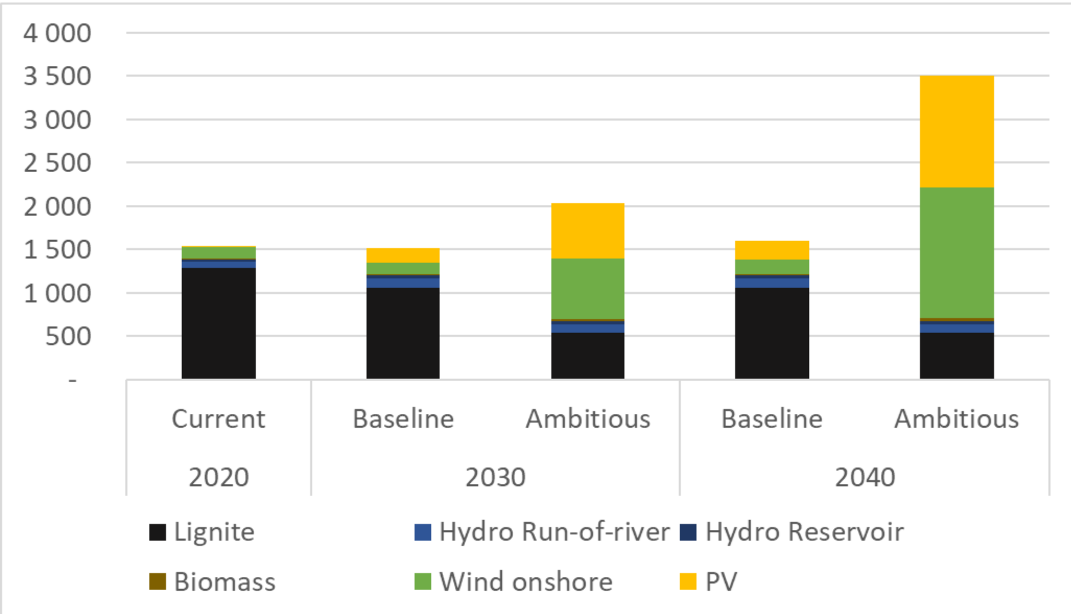

Figure 125 - Installed capacity (MW) in the different horizons and scenarios, Kosovo*

Evolution of interconnections

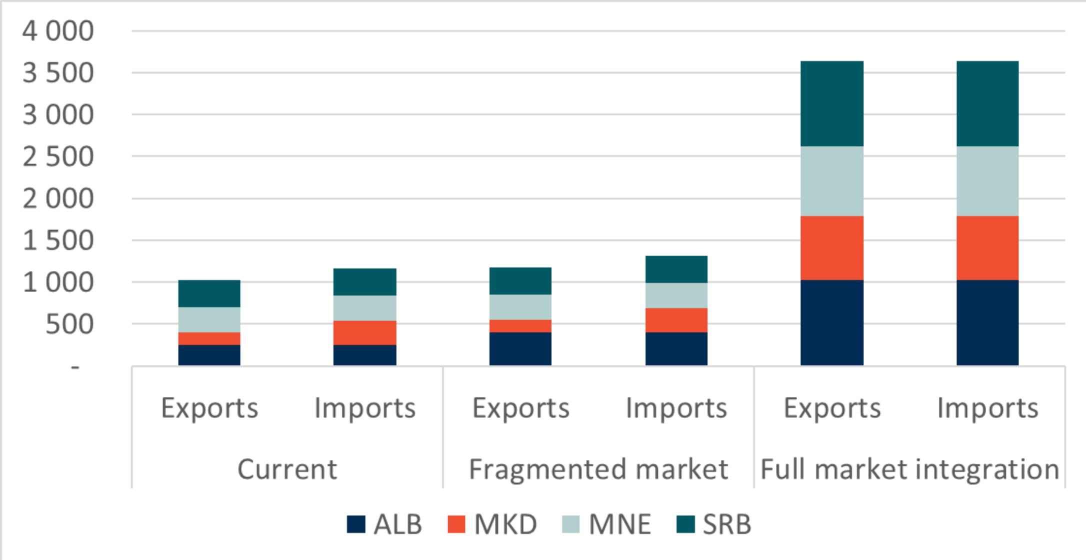

Figure 126 - NTC capacities (MW) , Kosovo*

Evolution of flexibility needs

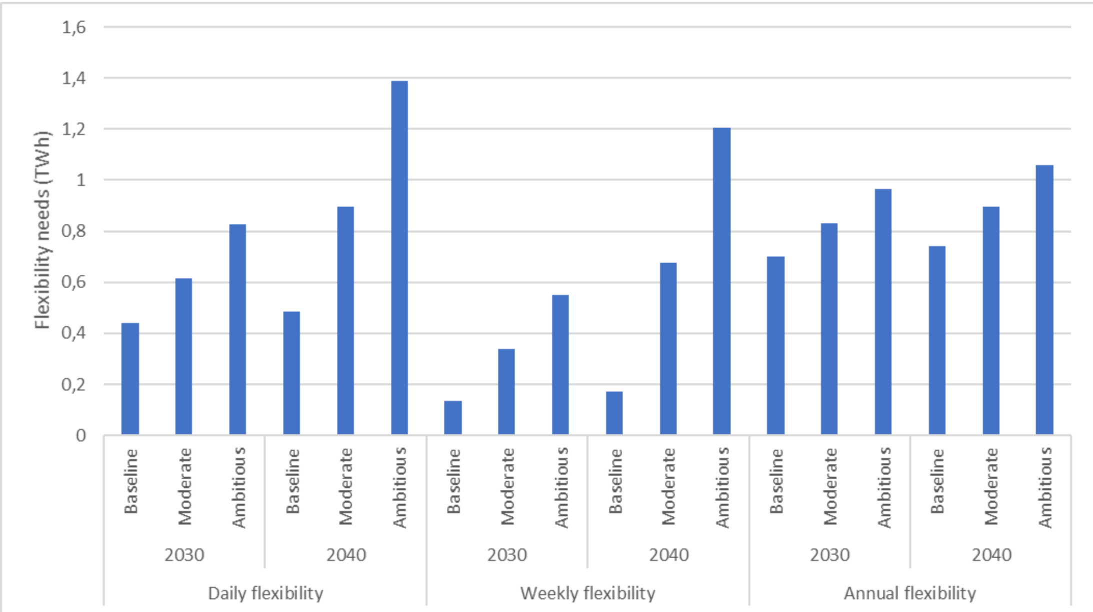

Figure 127 - Flexibility needs for 2030 and 2040, Kosovo*

8.4.2 Generation and flexibility supply by source

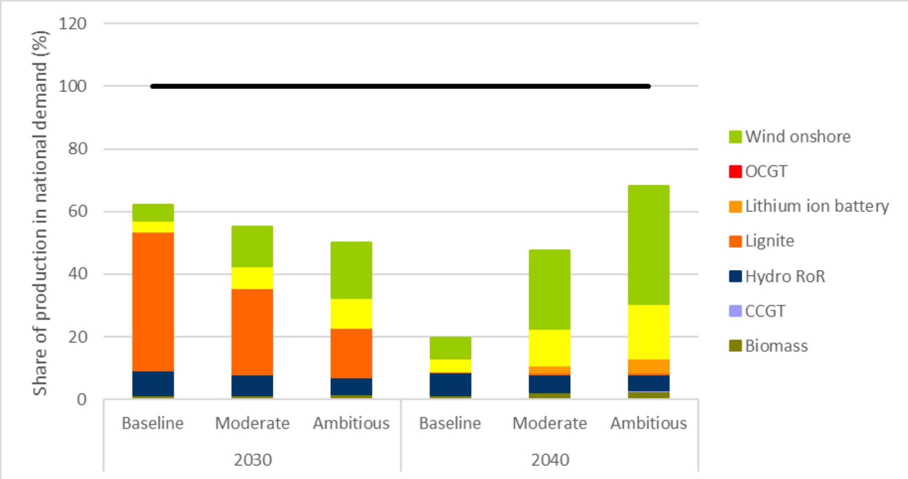

Figure 128 - Share of production in national demand (%), Kosovo*

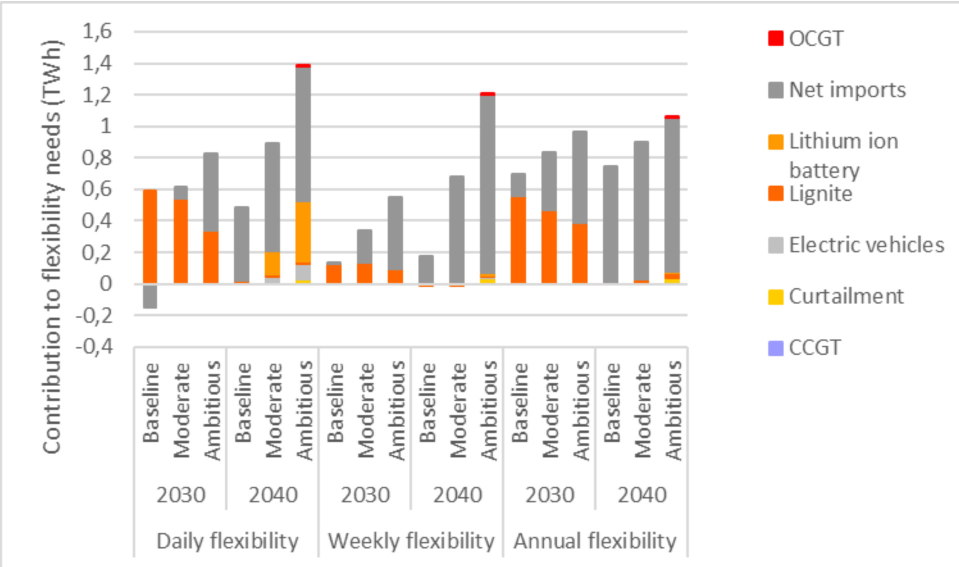

Figure 129 - Contribution to flexibility needs (TWh), Kosovo*

8.4.3 Capacity expansion results

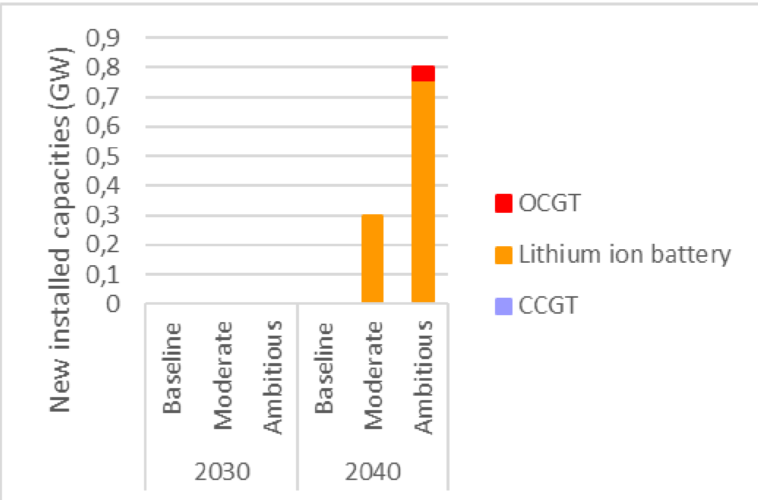

Figure 130 - Capacity expansion (GW), Kosovo*

8.4.4 CO2 emissions

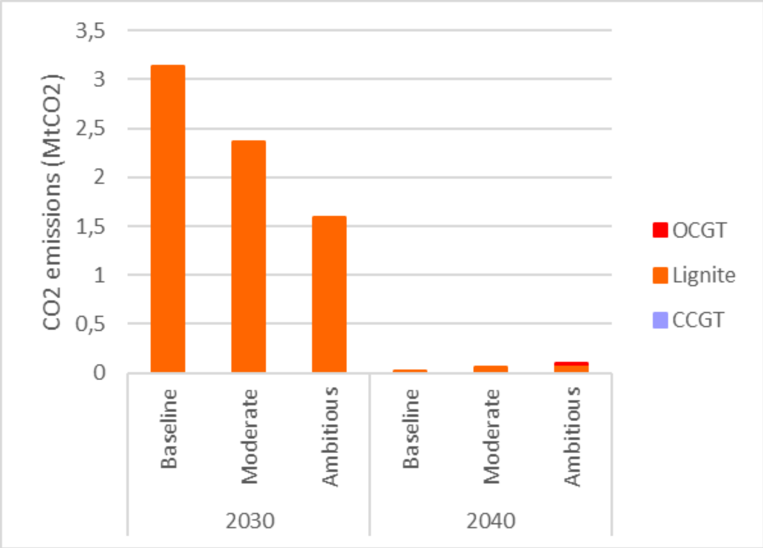

Figure 131 - CO2 emissions (MtCO2), Kosovo*

8.4.5 Cumulative generation

Summer week

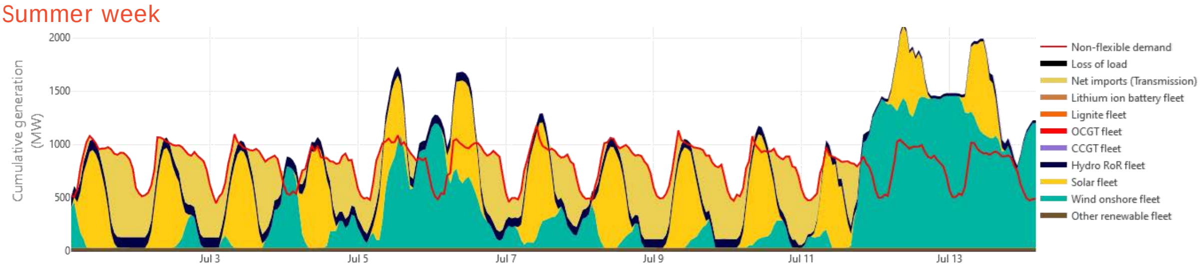

Figure 132 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Kosovo*

Winter week

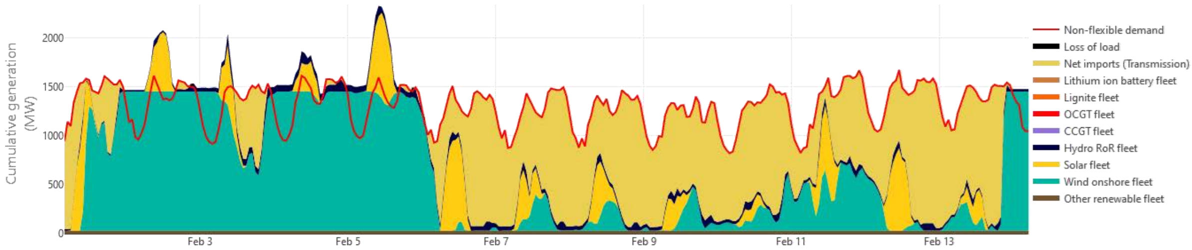

Figure 133 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Kosovo*

8.5 Montenegro

By default, the market scenario considered is the Fragmented Market scenario.

8.5.1 *Scenario description*

Evolution of demand

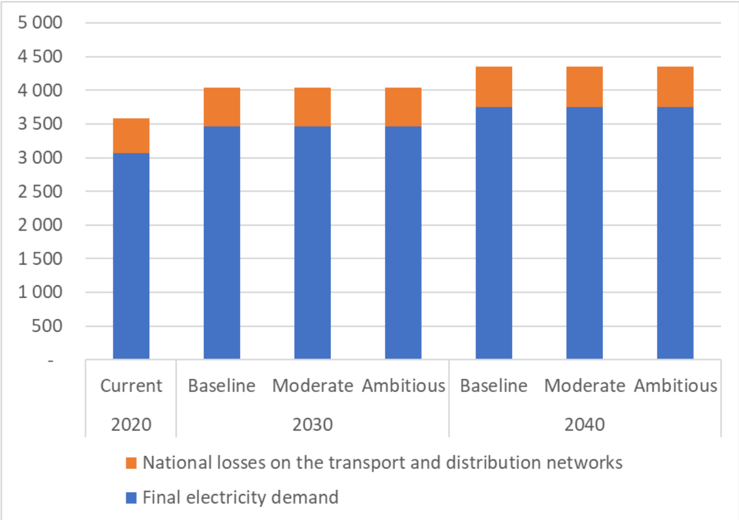

Figure 134 - Demand (GWh) in the different horizons and scenarios, Montenegro

Evolution of supply

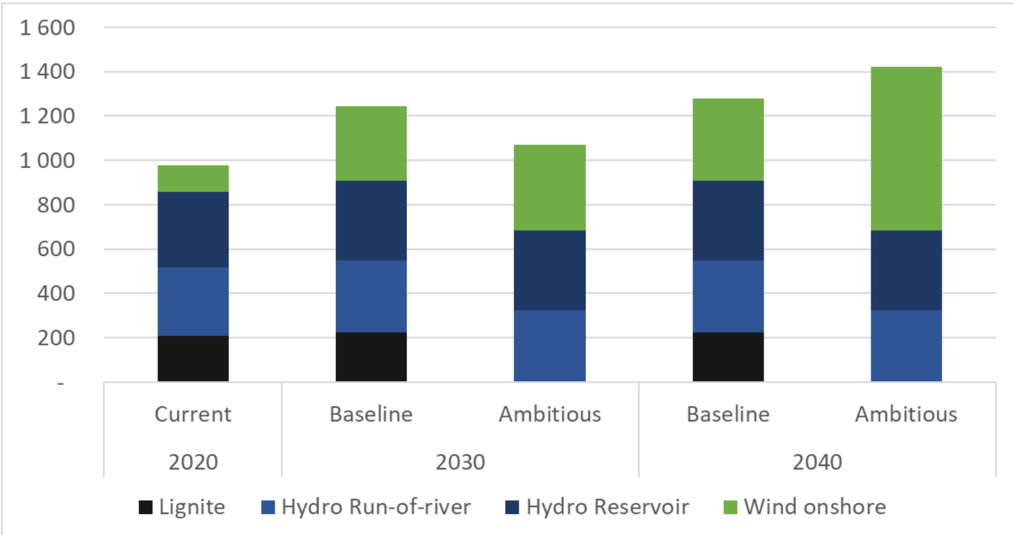

Figure 135 - Installed capacity (MW) in the different horizons and scenarios, Montenegro

Evolution of interconnections

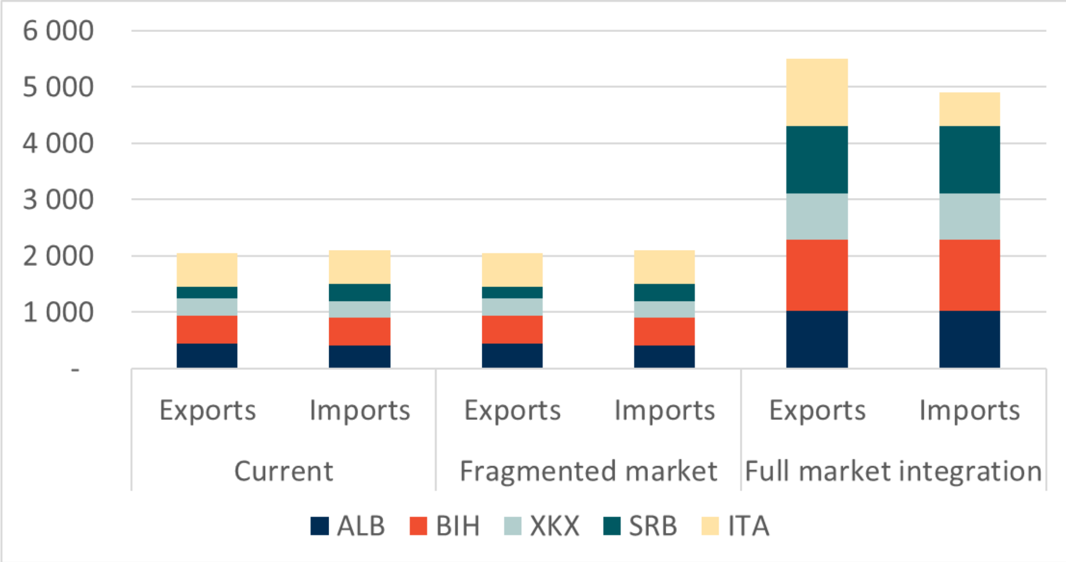

Figure 136 - NTC capacities (MW), Montenegro

Evolution of Flexibility needs

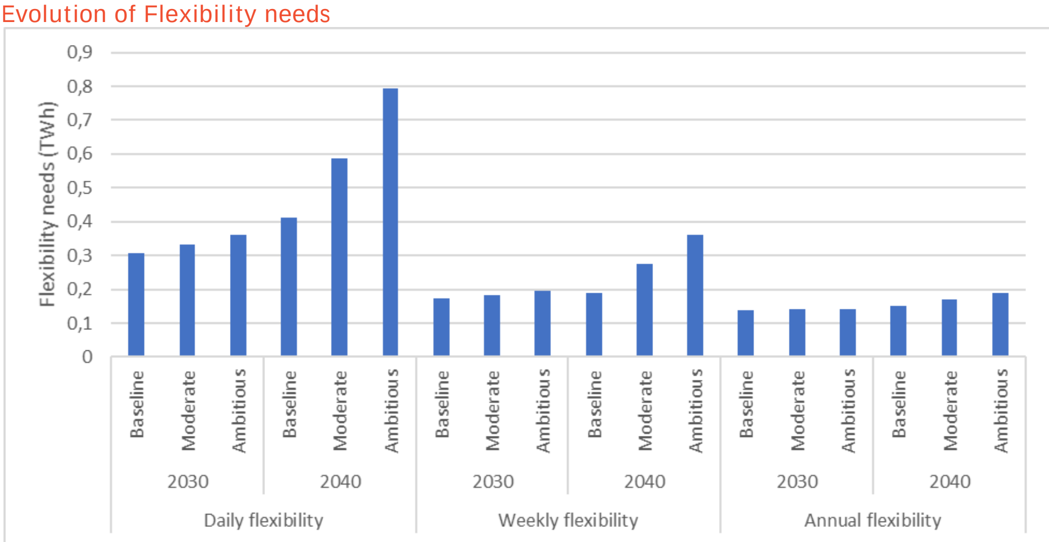

Figure 137 - Flexibility needs for 2030 and 2040, Montenegro

8.5.2 Generation and flexibility supply by source

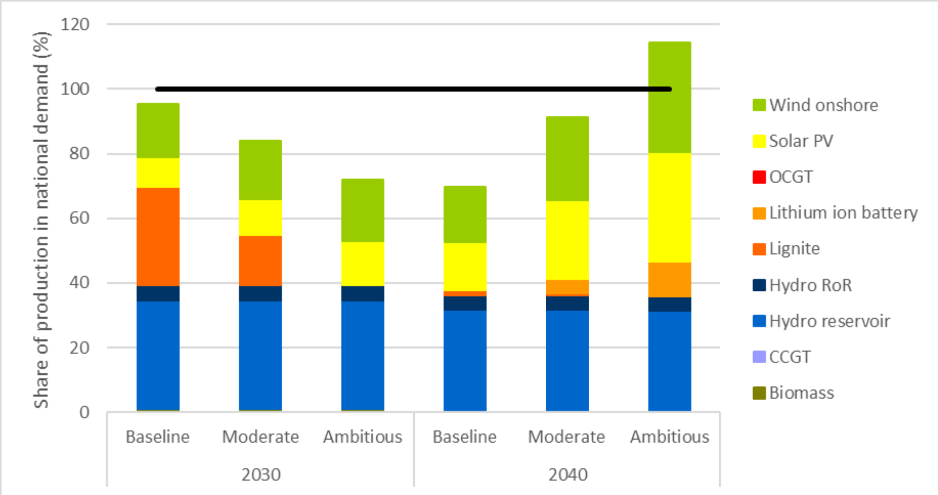

Figure 138 - Share of production in national demand (%), Montenegro

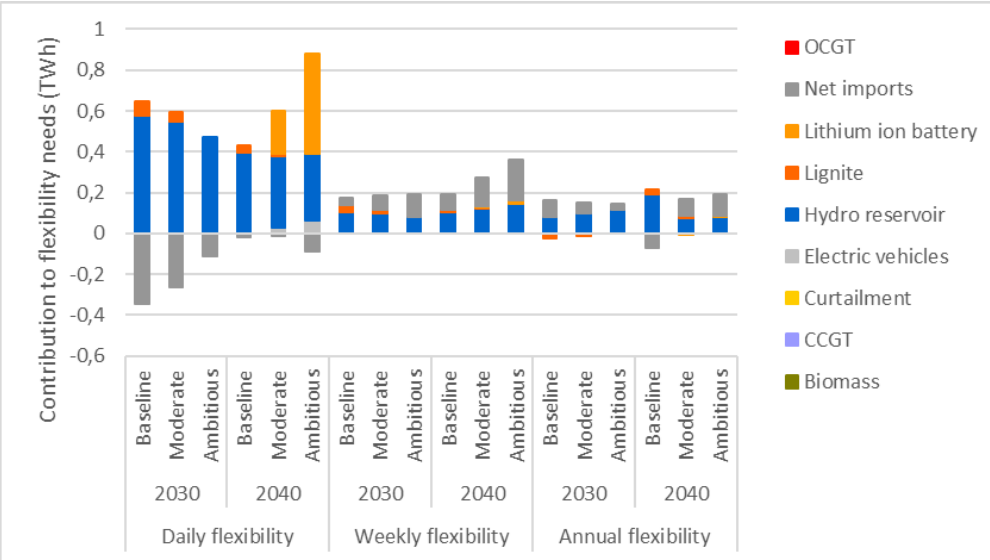

Figure 139 - Contribution to flexibility needs (TWh), Montenegro

8.5.3 Capacity expansion results

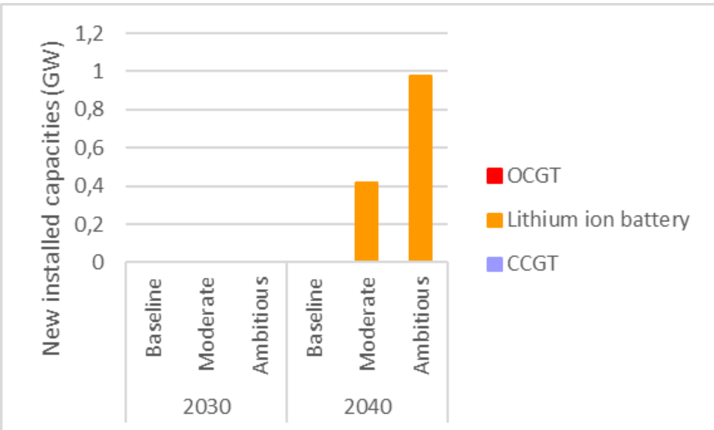

Figure 140 - Capacity expansion (GW), Montenegro

8.5.4 CO2 emissions

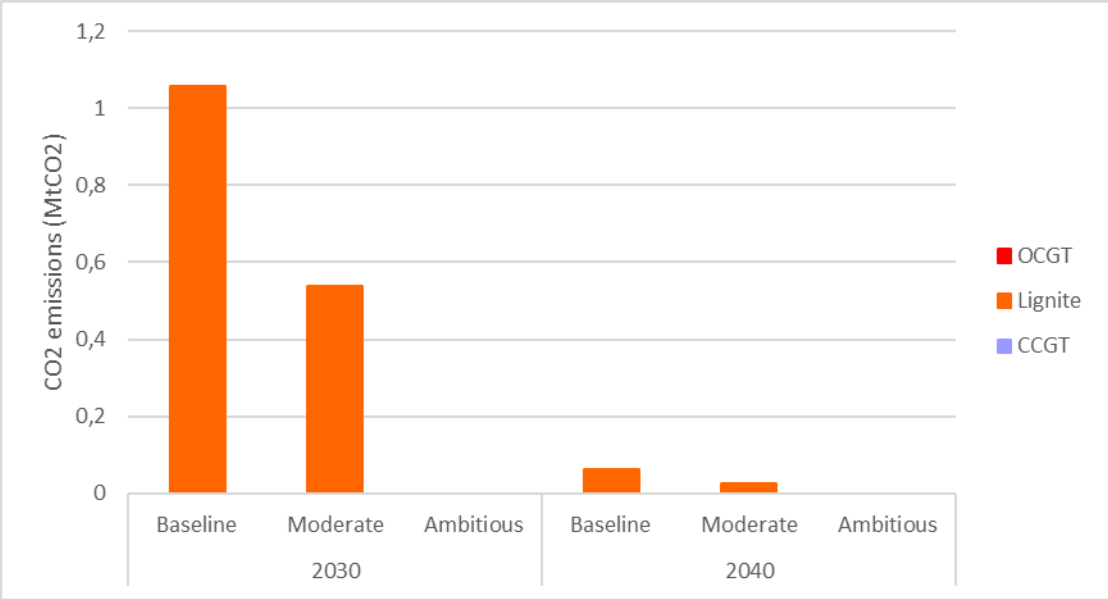

Figure 141 - CO2 emissions (MtCO2), Montenegro

8.5.4.1 Cumulative generation

Summer week

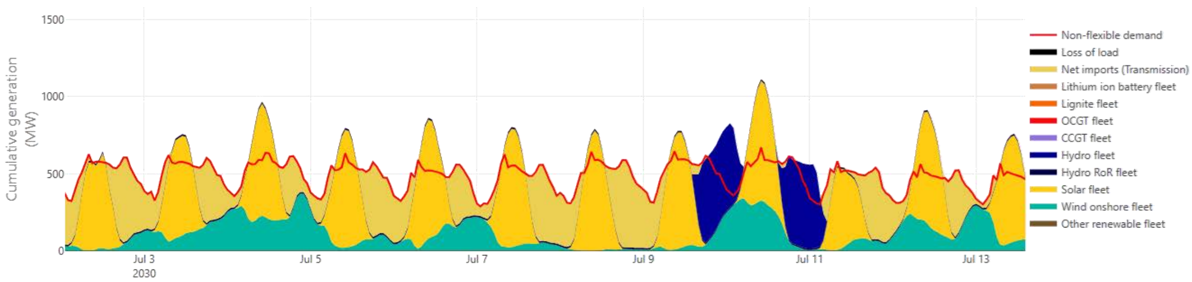

Figure 142 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Montenegro

Winter week

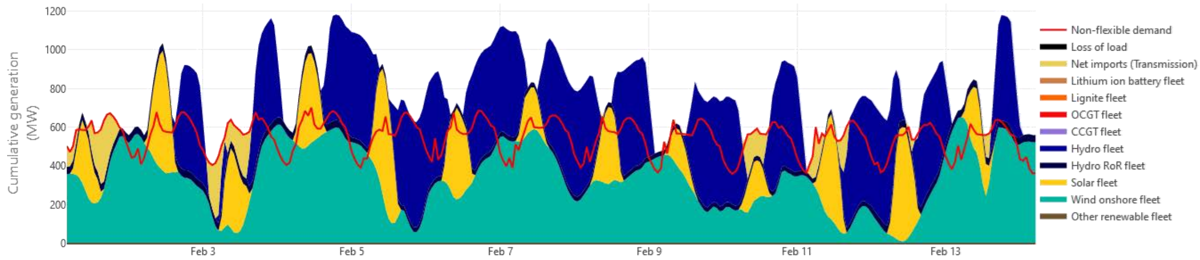

Figure 143 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Montenegro

8.6 Moldova

By default, the market scenario considered is the Fragmented Market scenario.

8.6.1 Scenario description

Evolution of demand

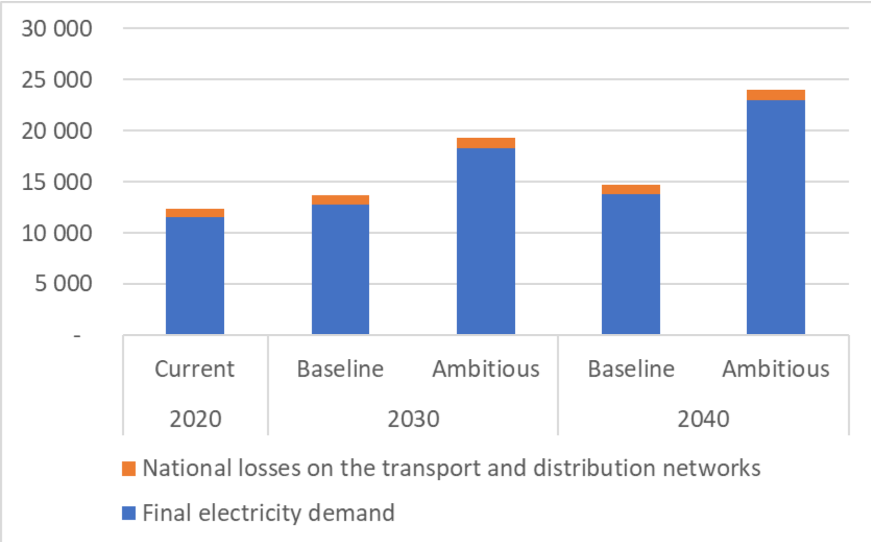

Figure 144 - Demand (GWh) in the different horizons and scenarios, Moldova

Evolution of supply

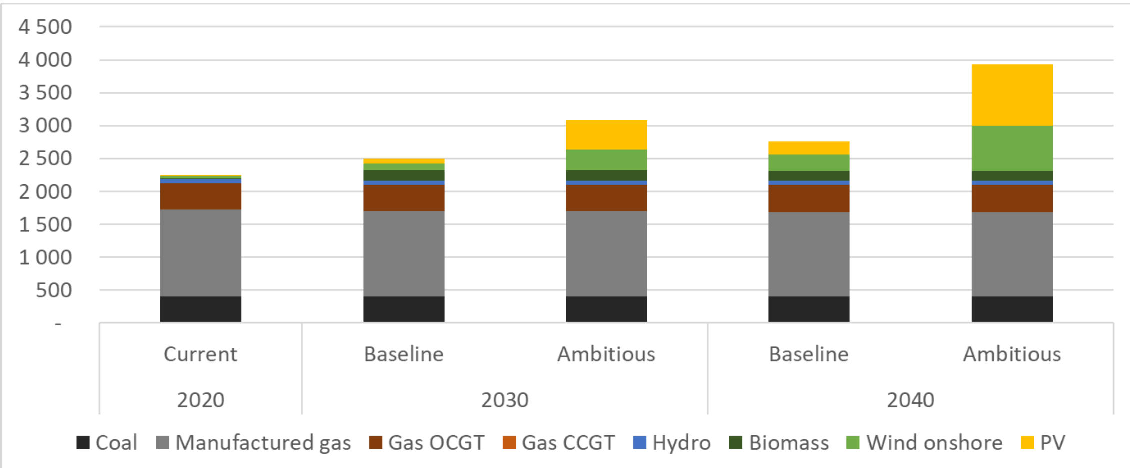

Figure 145 - Installed capacity (MW) in the different horizons and scenarios, Moldova

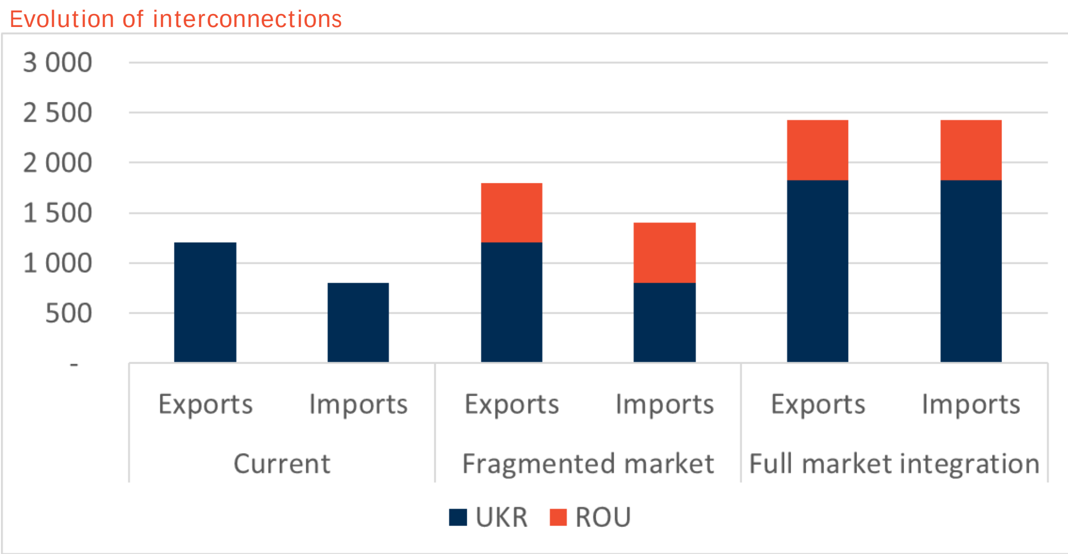

Figure 146 - NTC capacities (MW) , Moldova

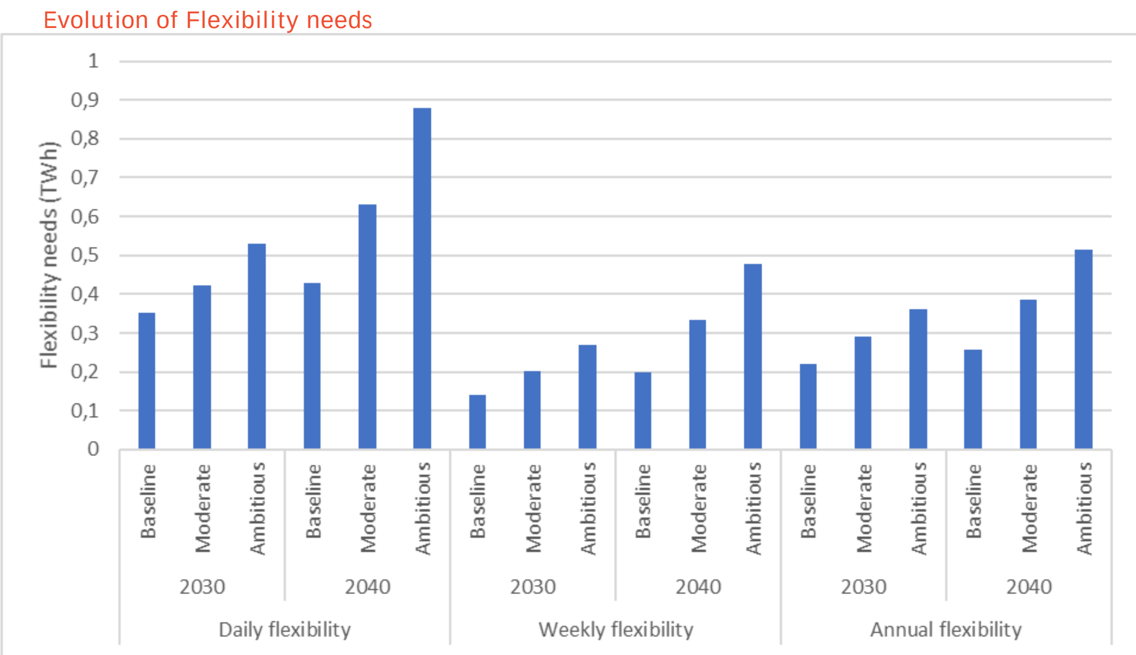

Figure 147 - Flexibility needs for 2030 and 2040, Moldova

8.6.2 Generation and flexibility supply by source

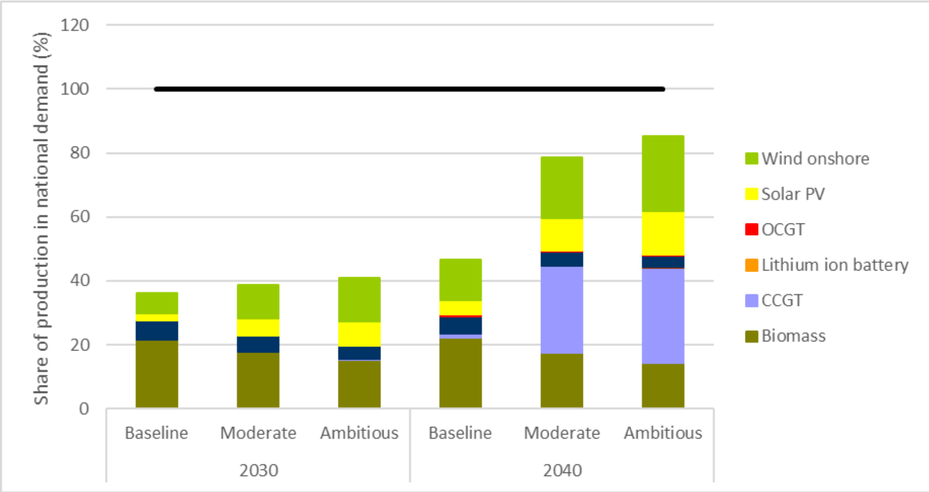

Figure 148 - Share of production in national demand (%), Moldova

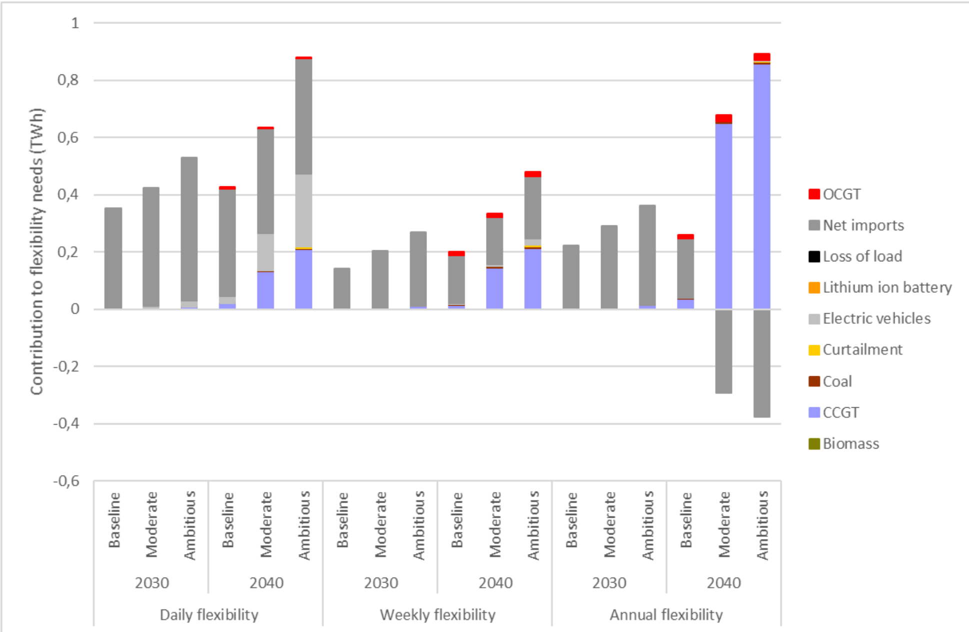

Figure 149 - Contribution to flexibility needs (TWh), Moldova

8.6.3 Capacity expansion results

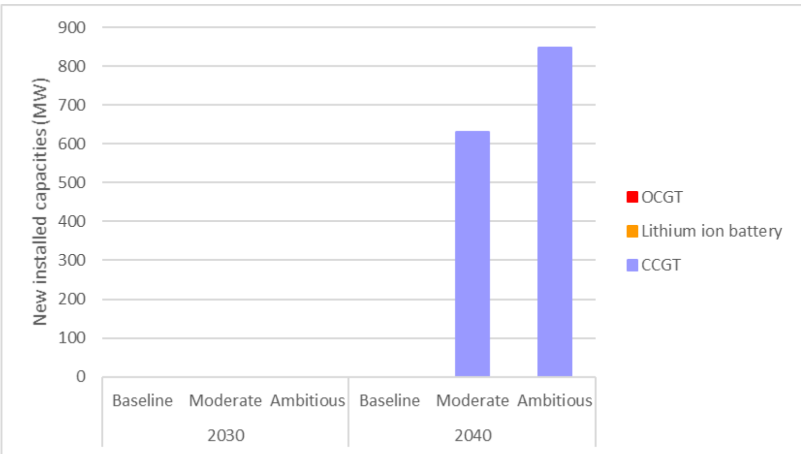

Figure 150 - Capacity expansion (GW), Moldova

8.6.4 CO2 emissions

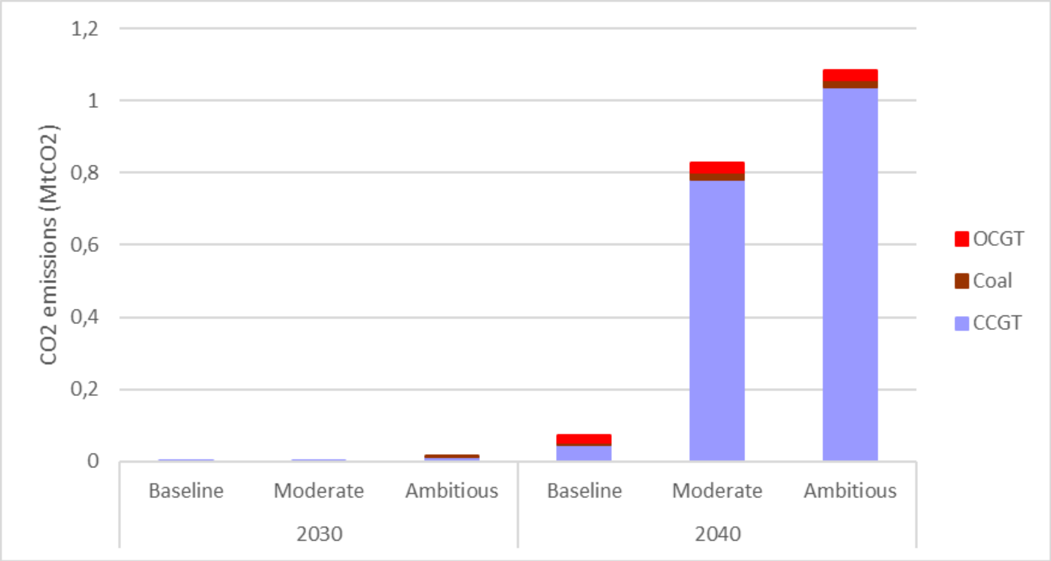

Figure 151 - CO2 emissions (MtCO2), Moldova

8.6.5 Cumulative generation

Summer week

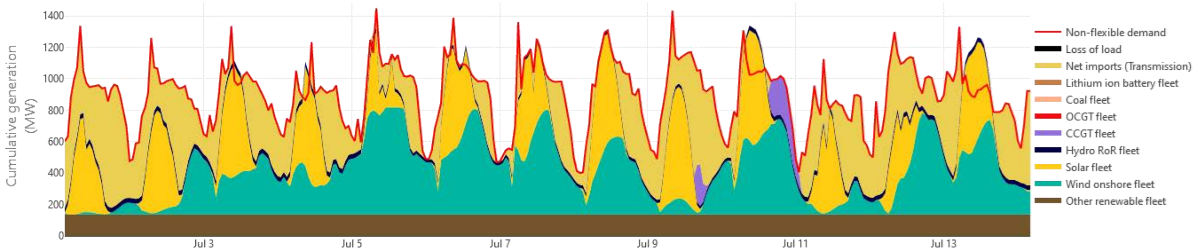

Figure 152 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Moldova

Winter week

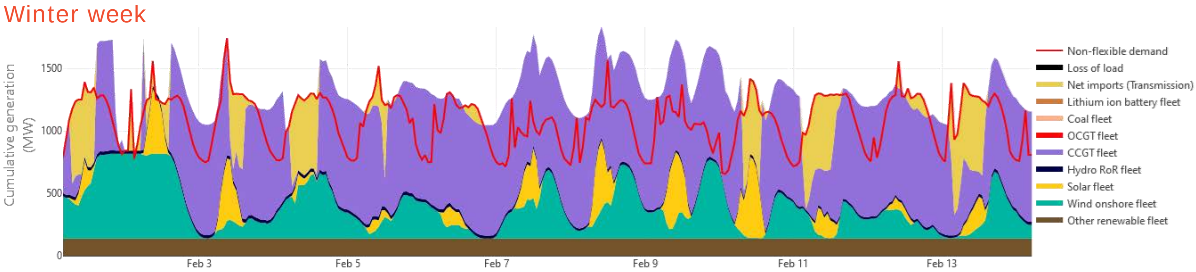

Figure 153 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Moldova

8.7 North Macedonia

By default, the market scenario considered is the Fragmented Market scenario.

8.7.1 Scenario description

Evolution of demand

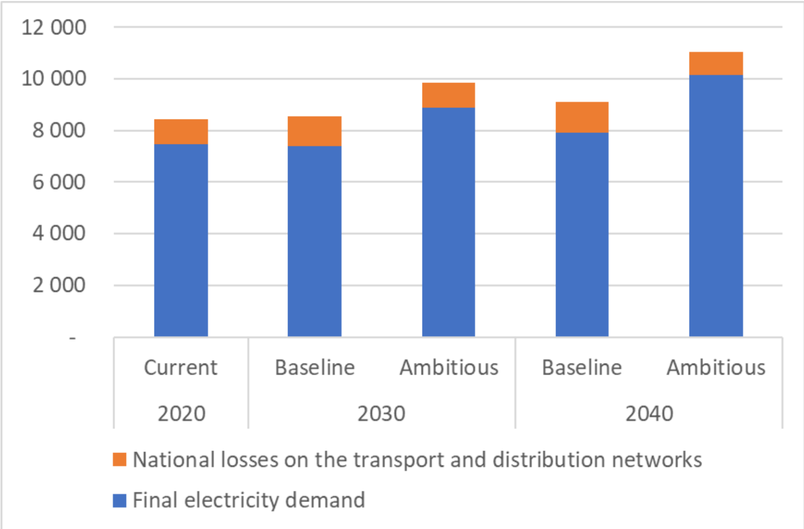

Figure 154 - Demand (GWh) in the different horizons and scenarios, North Macedonia

Evolution of supply

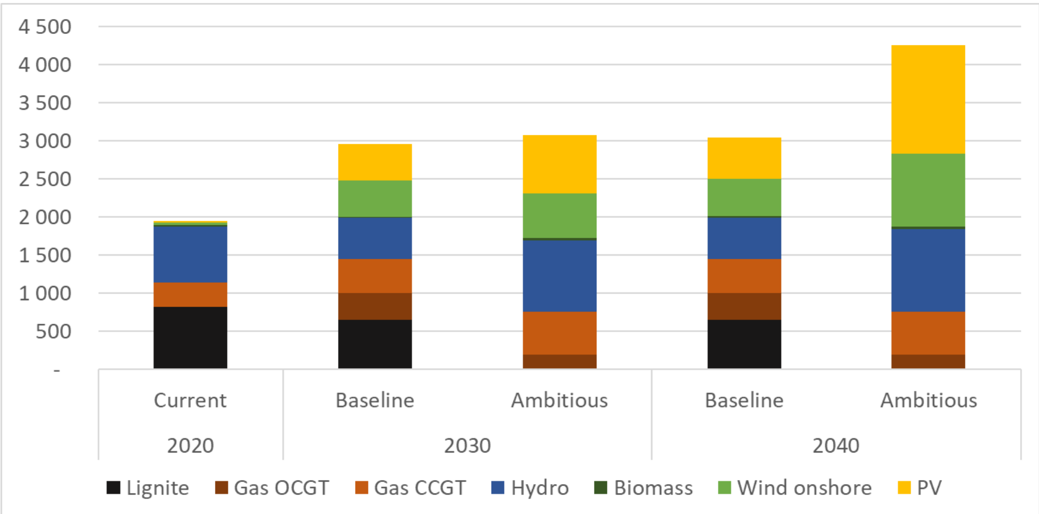

Figure 155 - Installed capacity (MW) in the different horizons and scenarios, North Macedonia

Evolution of interconnections

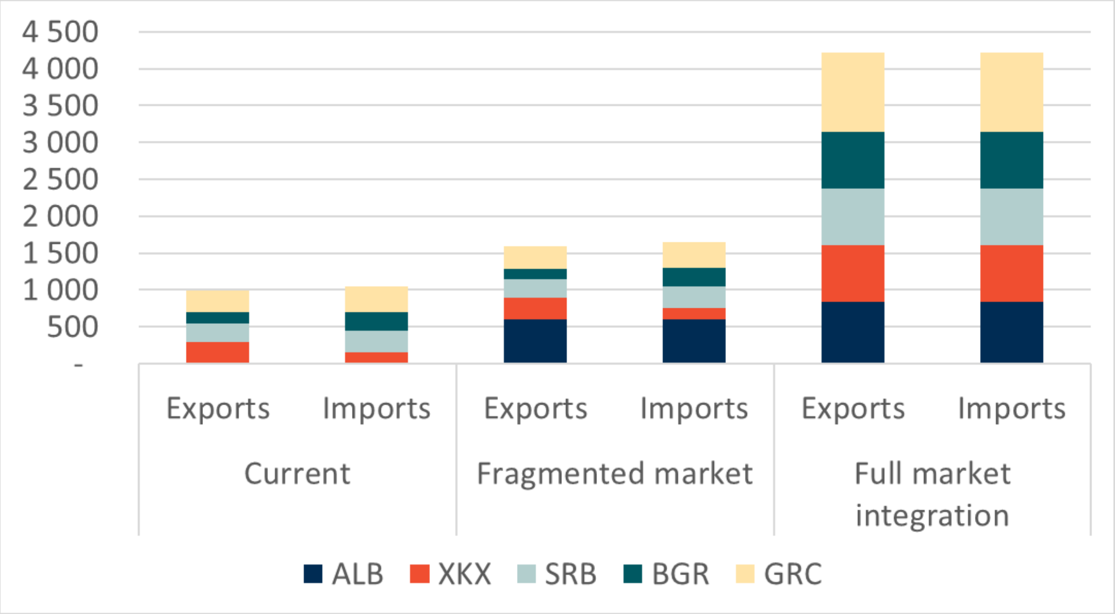

Figure 156 - NTC capacities (MW), North Macedonia

Evolution of Flexibility needs

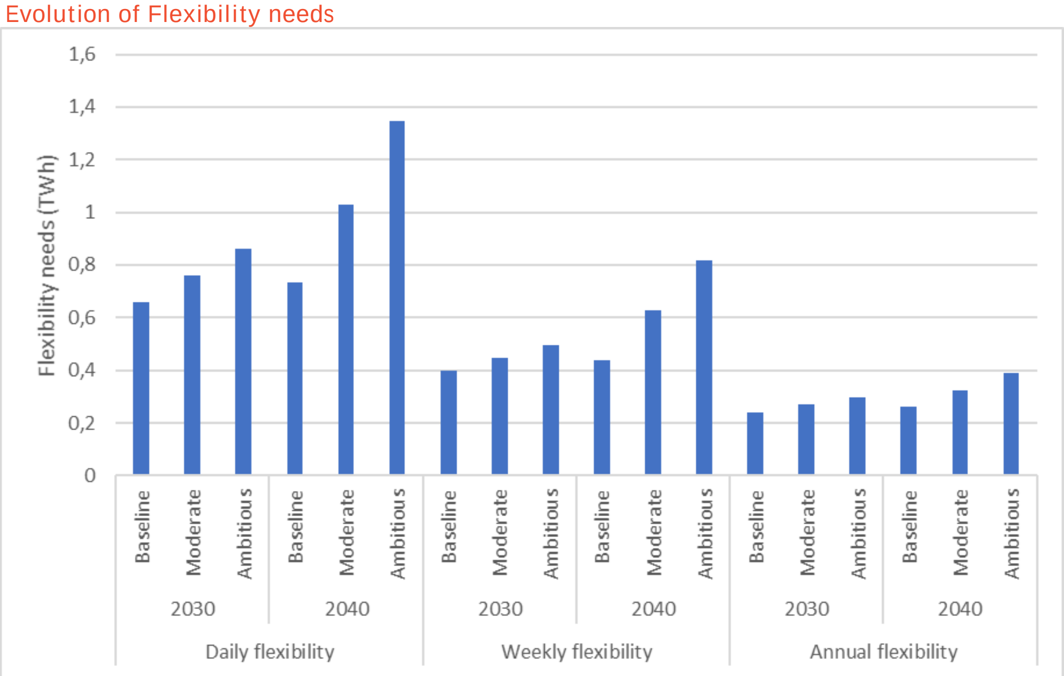

Figure 157 - Flexibility needs for 2030 and 2040, North Macedonia

8.7.2 Generation and flexibility supply by source

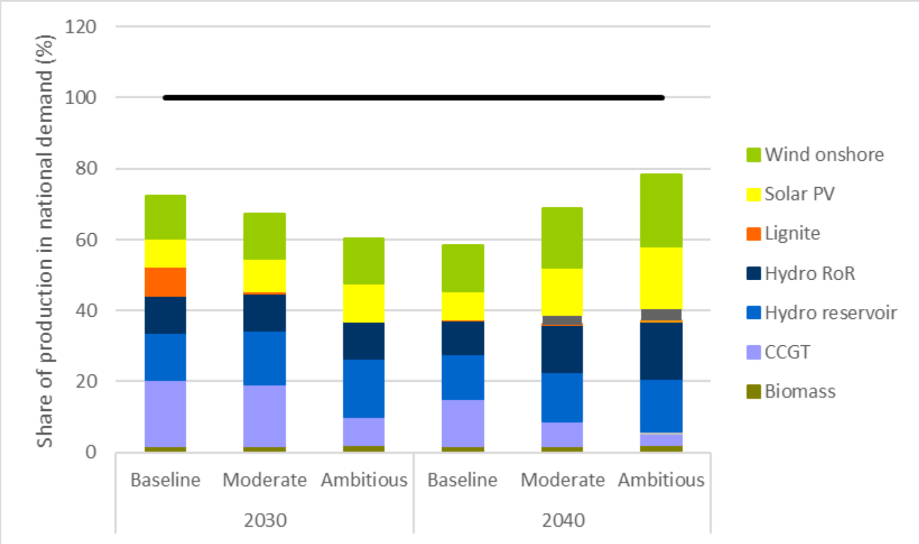

Figure 158 - Share of production in national demand (%), North Macedonia

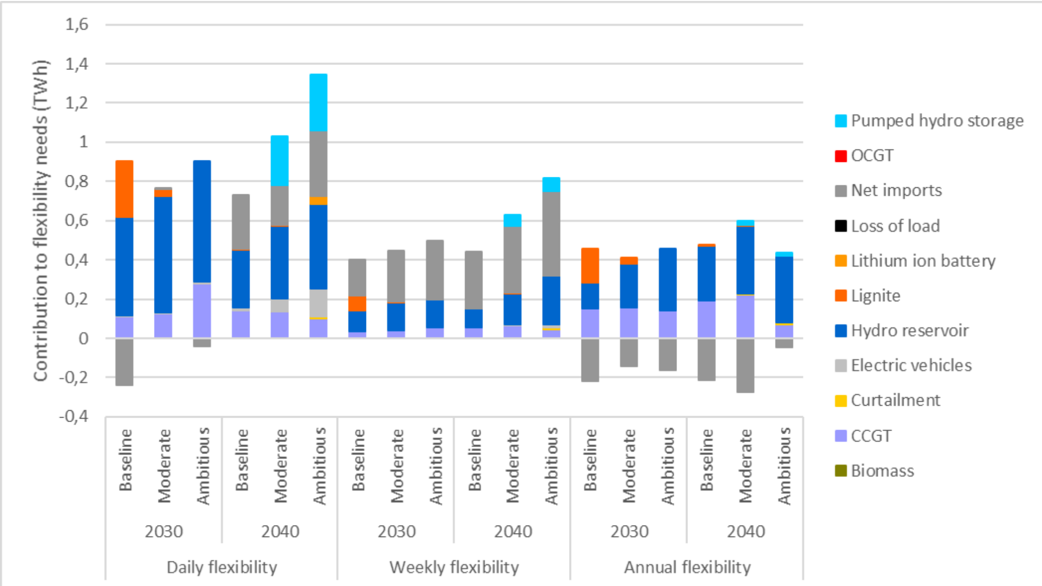

Figure 159 - Contribution to flexibility needs (TWh), North Macedonia

8.7.3 Capacity expansion results

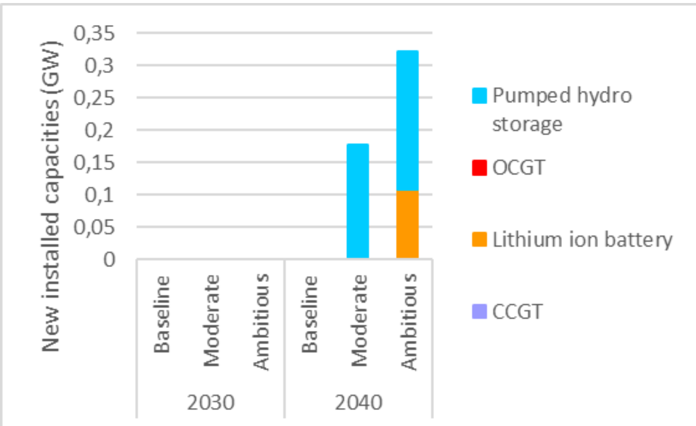

Figure 160 - Capacity expansion (GW), North Macedonia

8.7.4 CO2 emissions

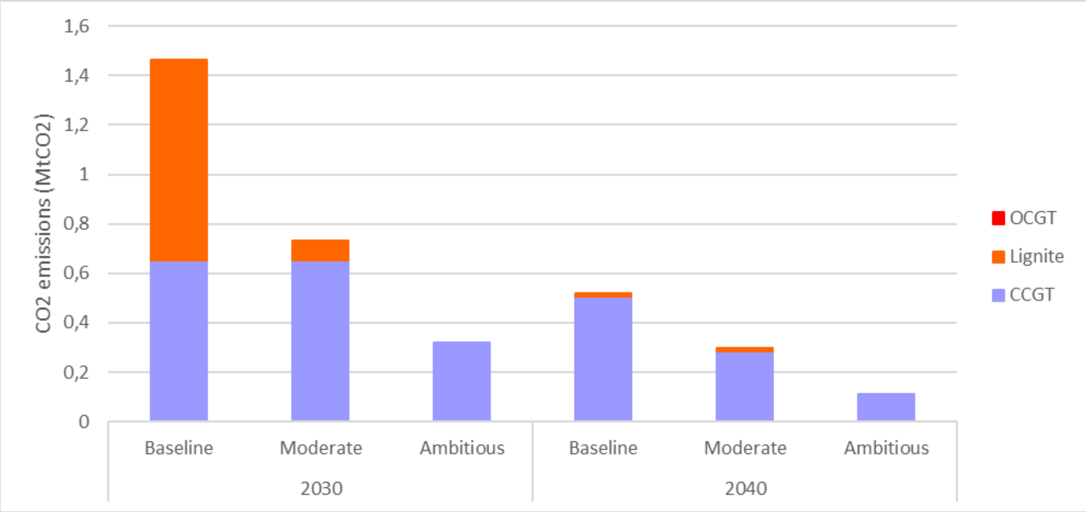

Figure 161 - CO2 emissions (MtCO2), North Macedonia

8.7.5 Cumulative generation

Summer week

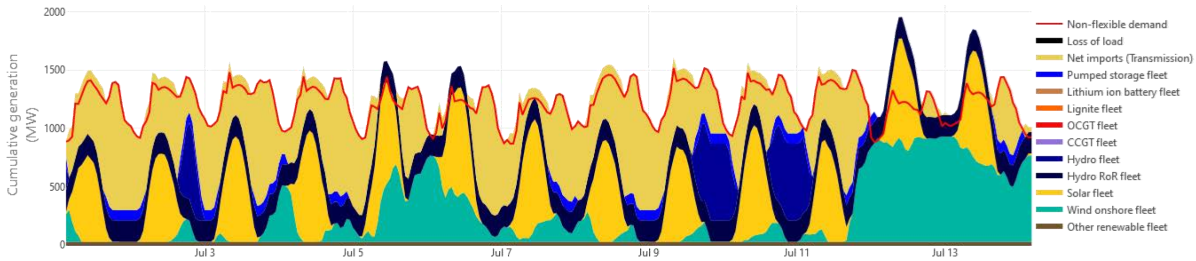

Figure 162 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, North Macedonia

Winter week

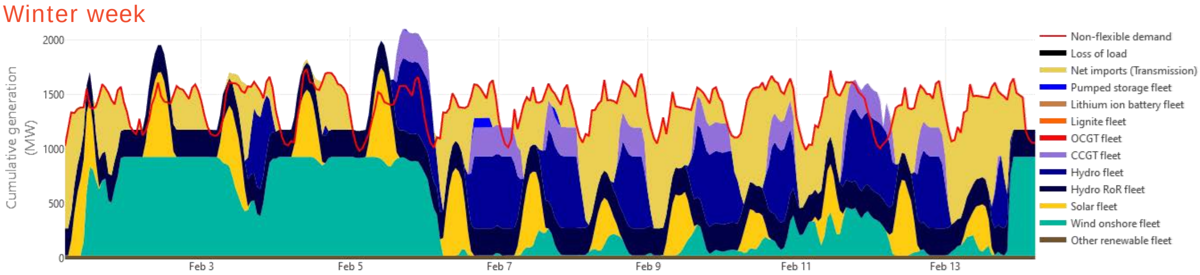

Figure 163 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, North Macedonia

8.8 Serbia

By default, the market scenario considered is the Fragmented Market scenario.

8.8.1 Scenario description

Evolution of demand

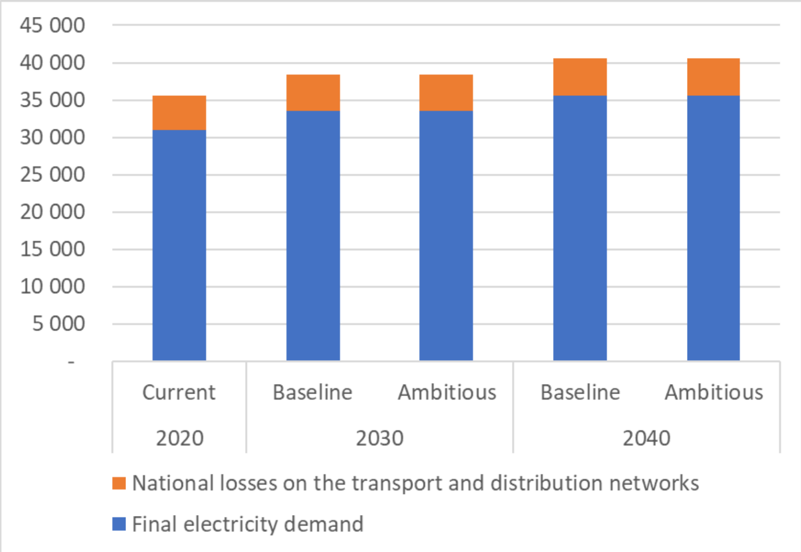

Figure 164 - Demand (GWh) in the different horizons and scenarios, Serbia

Evolution of supply

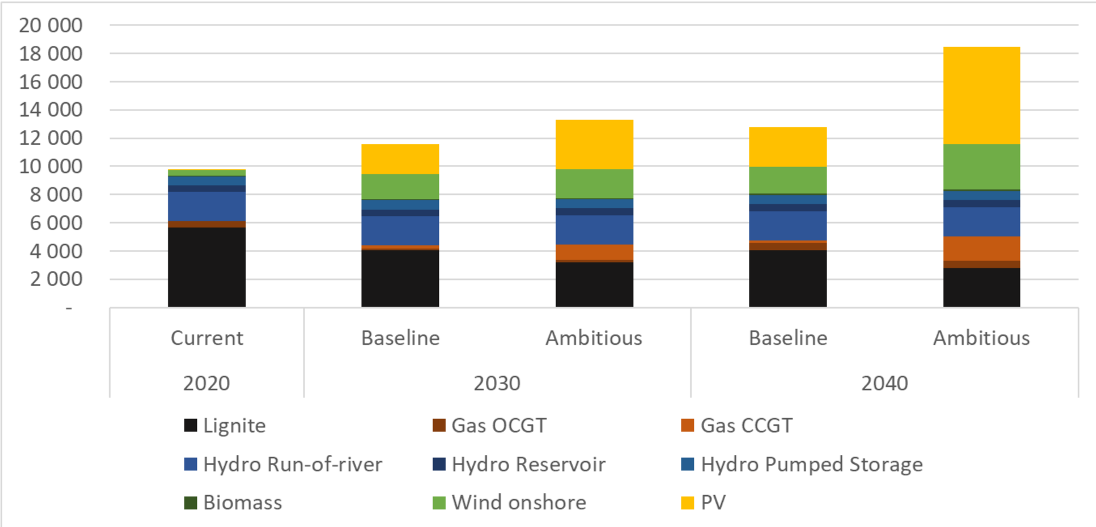

Figure 165 - Installed capacity (MW) in the different horizons and scenarios, Serbia

Evolution of interconnections

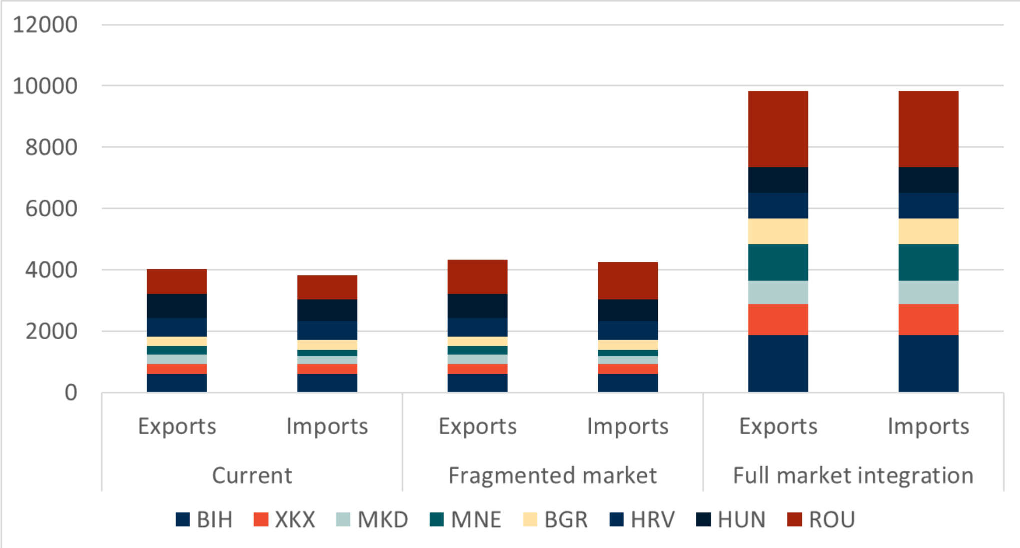

Figure 166 - NTC capacities (MW), Serbia

Evolution of Flexibility needs

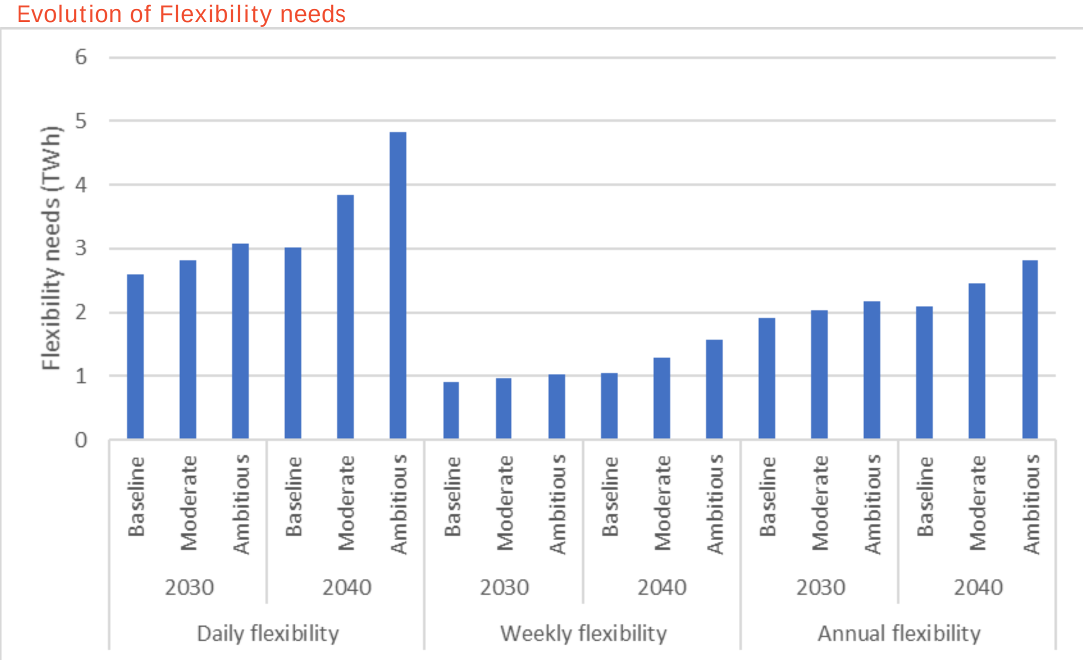

Figure 167 - Flexibility needs for 2030 and 2040, Serbia

8.8.2 Generation and flexibility supply by source

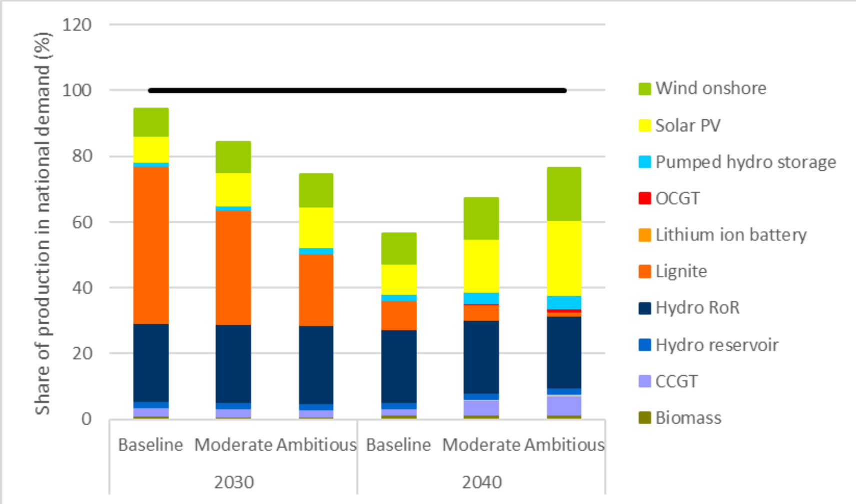

Figure 168 - Share of production in national demand (%), Serbia

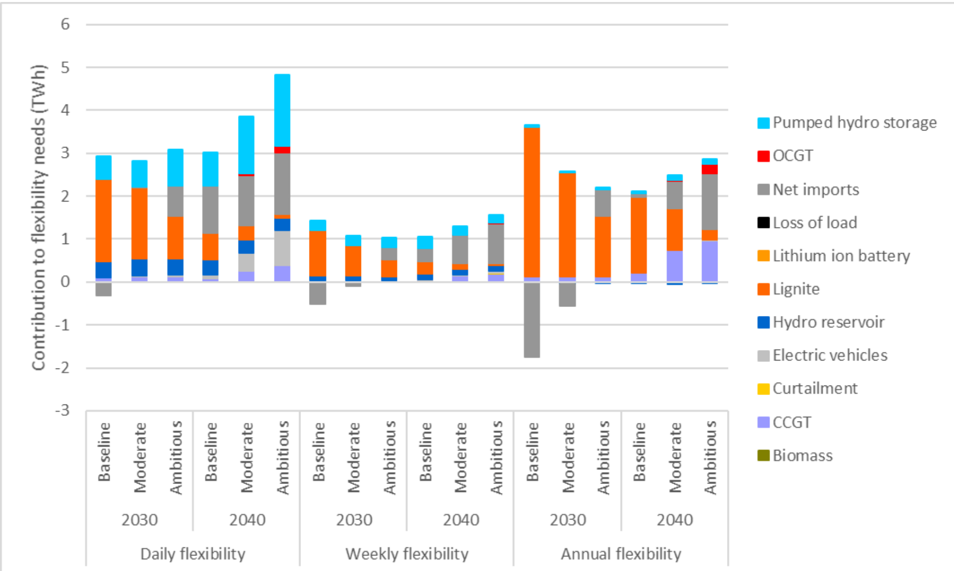

Figure 169 - Contribution to flexibility needs (TWh), Serbia

8.8.3 Capacity expansion results

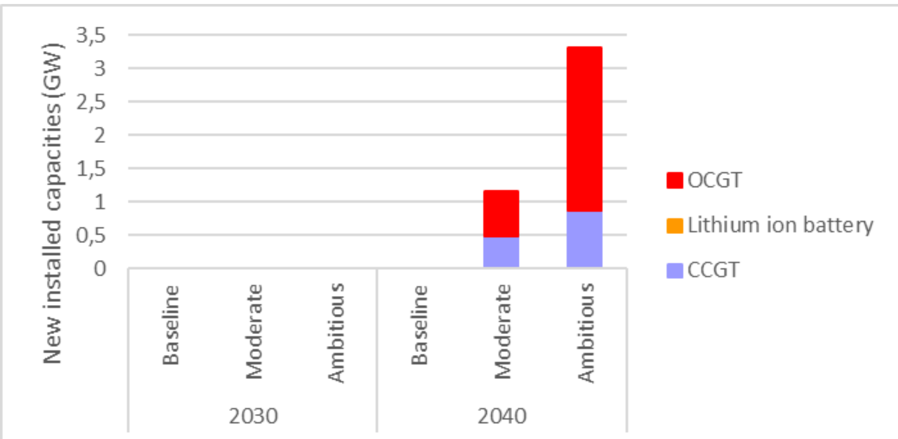

Figure 170 - Capacity expansion (GW), Serbia

8.8.4 CO2 emissions

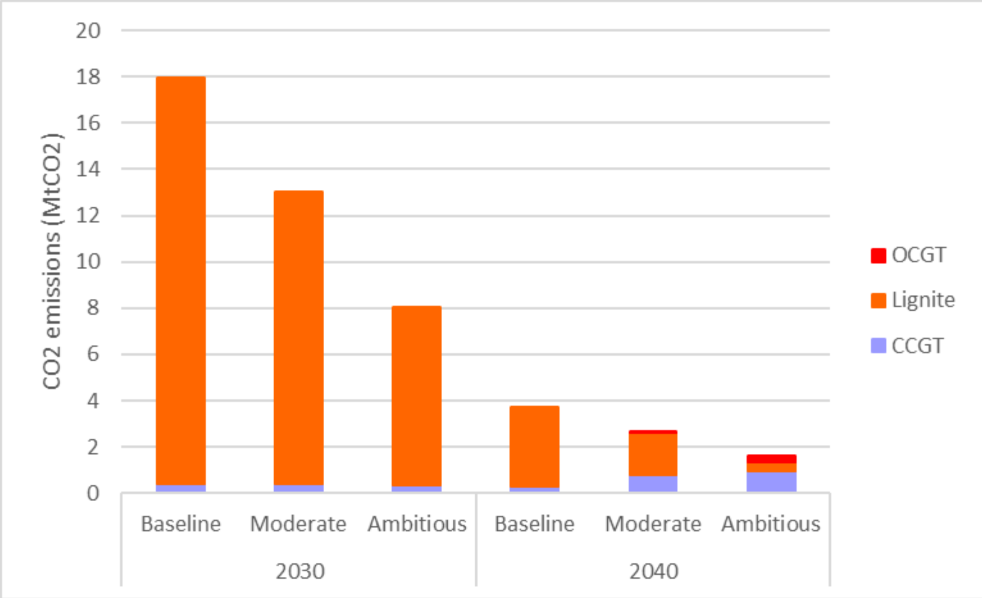

Figure 171 - CO2 emissions (MtCO2), Serbia

8.8.5 Cumulative generation

Summer week

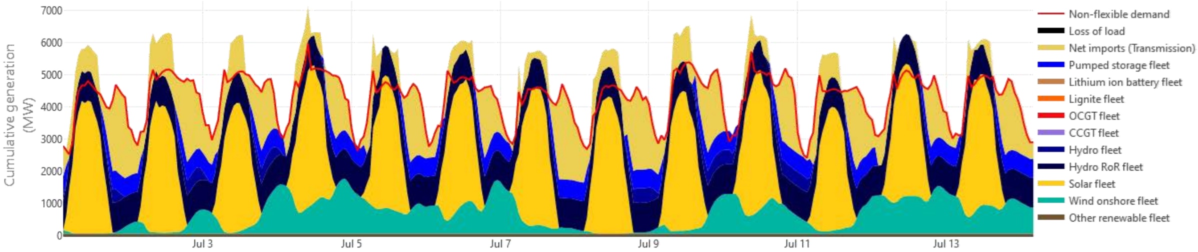

Figure 172 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Serbia

Winter week

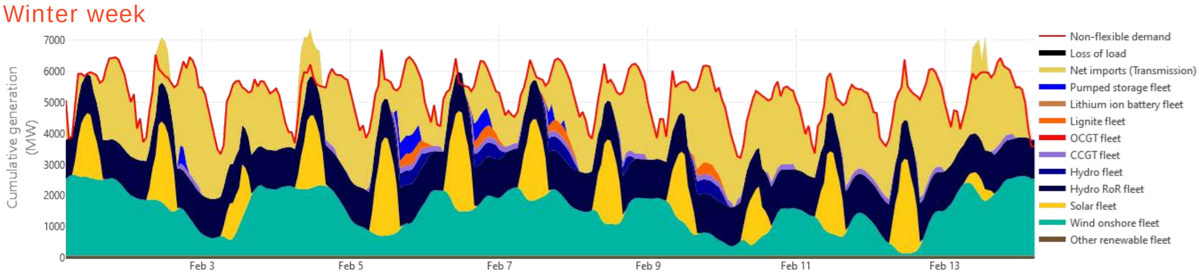

Figure 173 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Serbia

8.9 Ukraine

By default, the market scenario considered is the Fragmented Market scenario.

8.9.1 Scenario description

Evolution of demand

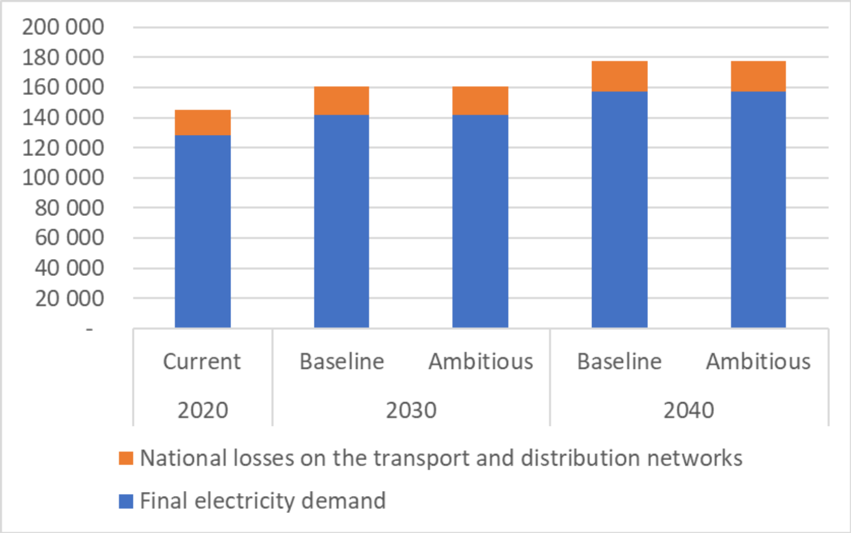

Figure 174 - Demand (GWh) in the different horizons and scenarios, Ukraine

Evolution of supply

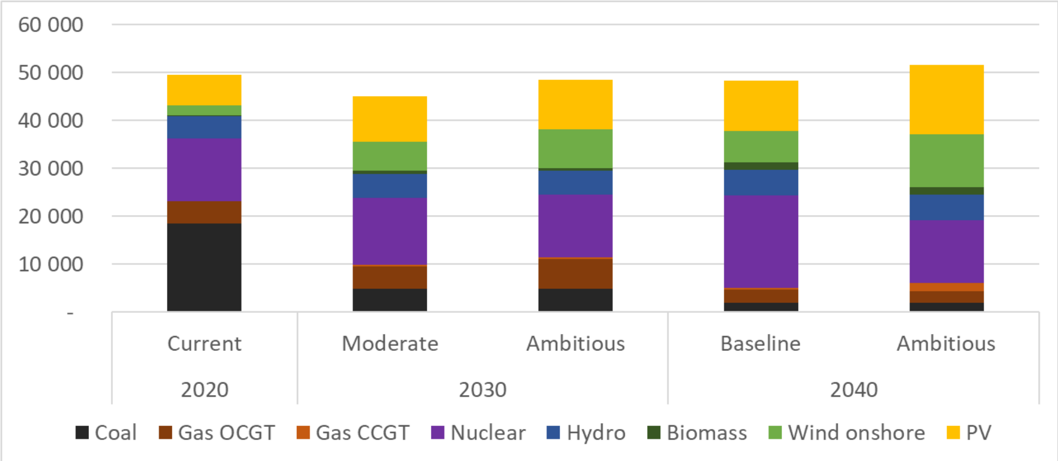

Figure 175 - Installed capacity (MW) in the different horizons and scenarios, Ukraine

Evolution of interconnections

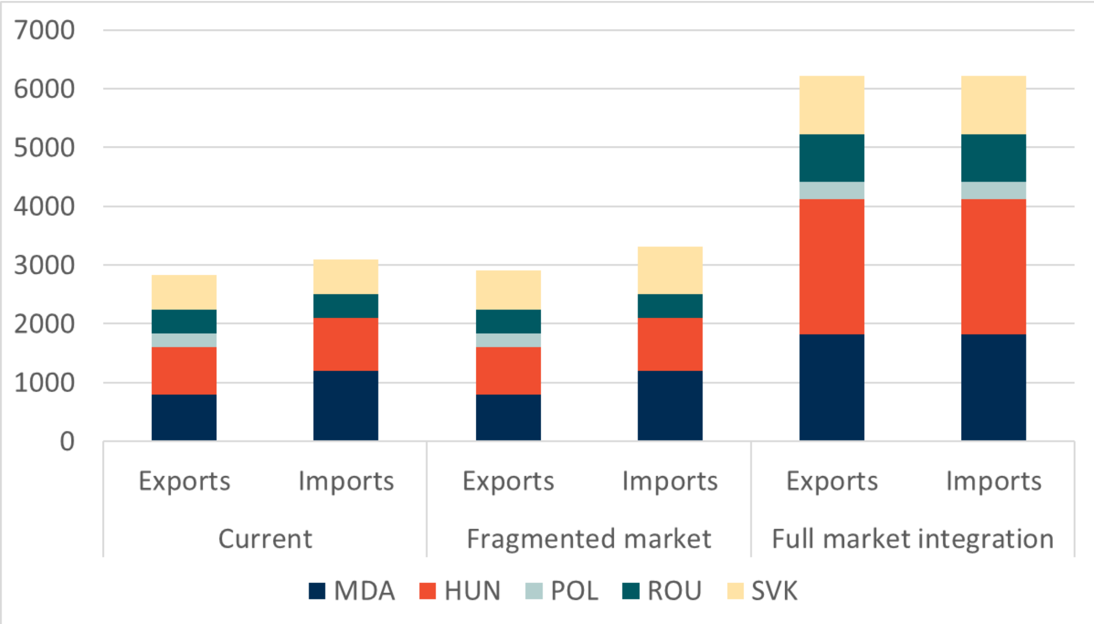

Figure 176 - NTC capacities (MW) , Ukraine

Evolution of Flexibility needs

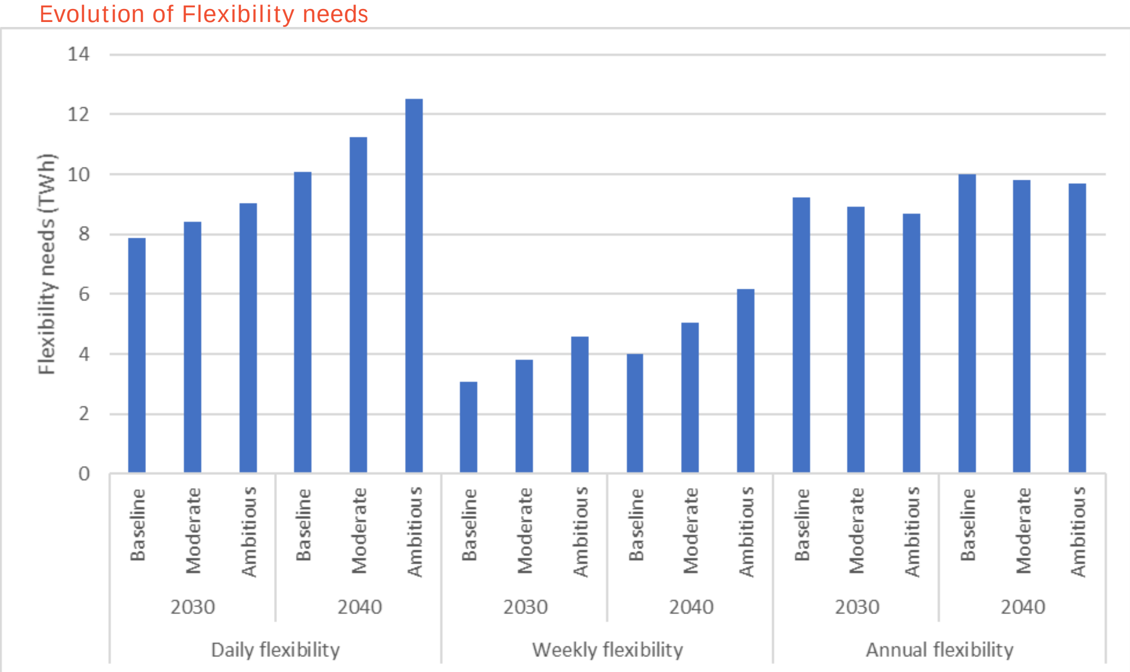

Figure 177 - Flexibility needs for 2030 and 2040, Ukraine

8.9.2 Generation and flexibility supply by source

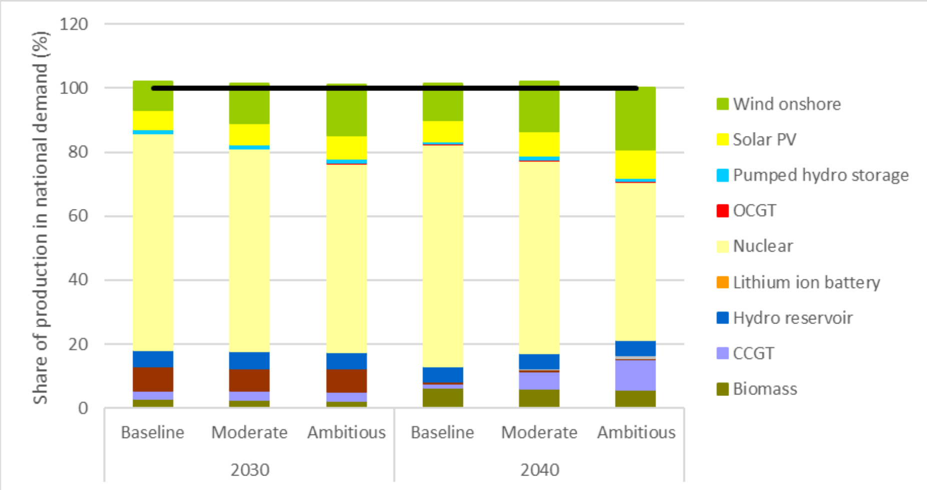

Figure 178 - Share of production in national demand (%), Ukraine

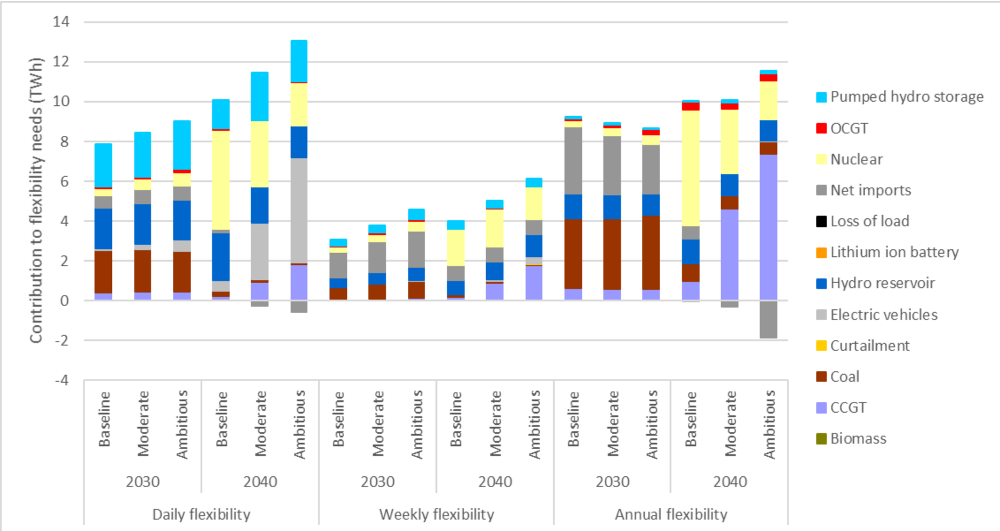

Figure 179 - Contribution to flexibility needs (TWh) , Ukraine

8.9.3 Capacity expansion results

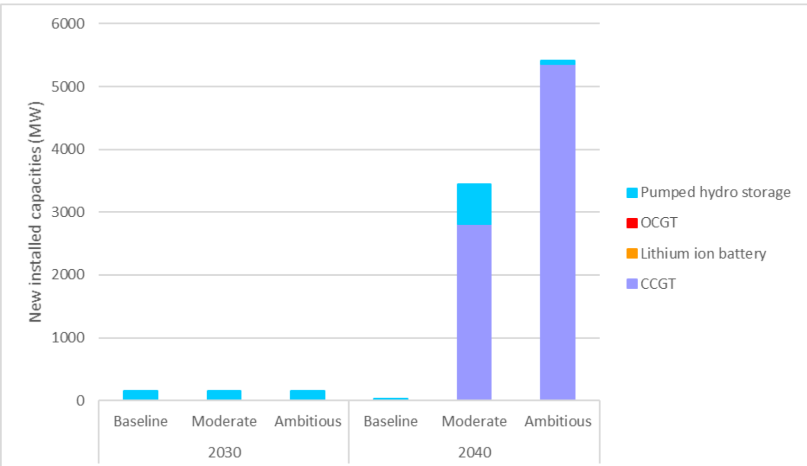

Figure 180 - Capacity expansion (GW), Ukraine

8.9.4 CO2 emissions

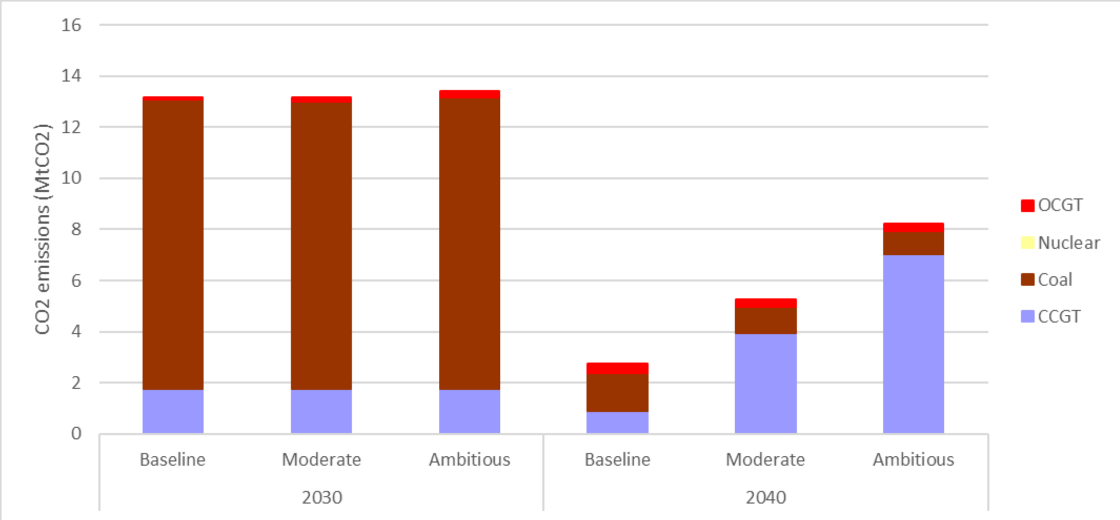

Figure 181 - CO2 emissions (MtCO2), Ukraine

8.9.5 Cumulative generation

Summer week

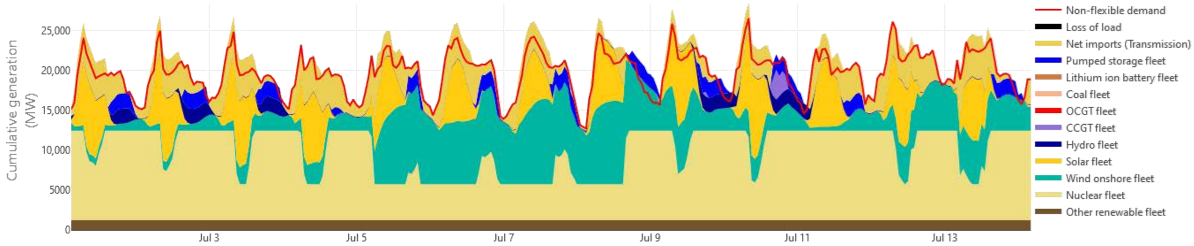

Figure 182 - Cumulative generation during a typical summer week in scenario Ambitious 2040 - Market Integration, Ukraine

Winter week

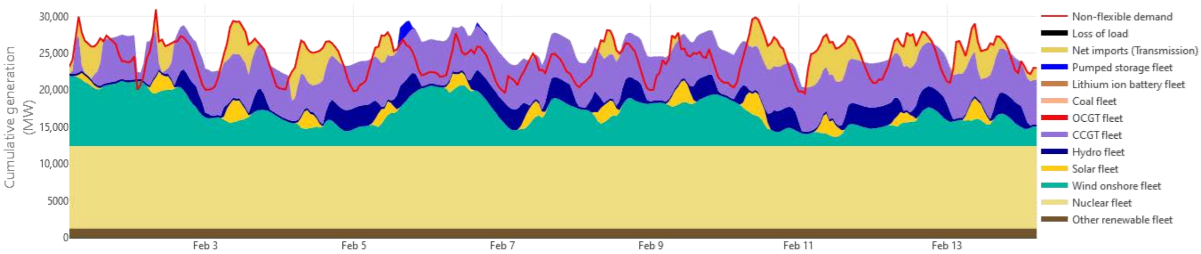

Figure 183 - Cumulative generation during a typical winter week in scenario Ambitious 2040 - Market Integration, Ukraine

Study on flexibility options to support decarbonization in the Energy Community

Tasks 4 and 5 Recommendations on flexibility sources and policy, legal and regulatory frameworks

Trinomics

Artelys OPTIMIZATION SOLUTIONS

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Acronyms

ACER	Agency for the Cooperation of Energy Regulators
AL	Albania
ALPEX	Albanian power exchange
AS	Ancillary services
BEI	Burshtyn Energy Island
BiH	Bosnia and Herzegovina
BRP	Balance responsible party
CAPEX	Capital expenditure
CBA	Cost-benefit analysis
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined cycle gas turbine
CCR	Capacity calculation regions
CEER	Council of European Energy Regulators
CfD	Contract for Difference
CESA	Continental Europe Synchronous Area
CESEC	Central and South Eastern Europe energy connectivity
CP	Contracting party
CR3	Concentration ratio measuring the total market shares of the 3 largest suppliers in one market
CRM	Capacity remuneration mechanisms
CSE	Continental South East
DA	Day-ahead
DSM	Demand side flexibility
DSO	Distribution system operator
EC	European Commission
ECRB	Energy Community Regulatory Board
ECS	Energy Community Secretariat
EED	Energy Efficiency Directive
EMS	Elektromreza Srbije
EnC	Energy Community
ENTSO-E	European Network of Transmission System Operators for Electricity
ERAA	European Resource Adequacy Assessment
ETS	Emissions Trading System
EU	European Union
EV	Electric vehicle
GE	Georgia
GW	Gigawatt
ID	Intra-day
IGCC	International Grid Control Cooperation
ICT	Information and communications technology
IT	Italy
MD	Moldova
ME	Montenegro
MGRES	Moldavskaya GRES
MK	North Macedonia
MW	Megawatt
NECP	National energy and climate plan
NRA	National regulatory authority
NTC	Net transfer capacity
OCGT	Open-cycle gas-turbine
OTC	Over-the-counter

PECI	Project of Energy Community Interest
PEPI	Projects of Eastern Partnership Interest
PHS	Pumped hydro storage
PMI	Projects of Mutual Interest
PPA	Power purchase agreement
PV	Photovoltaic
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable energy sources
RO	Romania
RS	Serbia
SDAC	Single day-ahead coupling
SEE	South East European
TSO	Transmission system operator
TYNDP	Ten-year network development plan
UA	Ukraine
UPS	Unified Power System of Russia
V2G	Vehicle to grid
VAT	Value Added Tax
WB6	Western Balkans 6
XK	Kosovo*

Executive Summary

This report presents the key findings of Tasks 4 & 5 of the "Study on flexibility options to support decarbonisation in the Energy Community". The previous reports of this study have focused on:

- ✓ Discussing what is flexibility, what are its main contributions and drivers, and characterising selected flexibility sources (Task 1)[1]; and
- ✓ Identifying the existing flexibility sources, analysing the flexibility needs across different timeframes (daily, weekly and annual) in the Energy Community as well as indicating the optimal flexibility portfolio in each Contracting Party in 2030 and 2040 (Tasks 2 & 3)[2].

The aim of this report is to provide recommendations for improvement of the legal, regulatory and institutional frameworks to enable 1) the efficient utilisation of flexibility sources and 2) develop additional flexibility sources in order to cost-efficiently meet future flexibility needs while assuring security of supply standards in the Energy Community. The report provides robust and no-regret recommendations such that, independent of the level of renewable energy deployment and fossil fuel-based power generation phase-out, the measures should bring overall societal benefits and facilitate the deployment and efficient utilisation of flexibility sources.

This report is organised as follows:

- ✓ Chapter 1 introduces the report's objective and scope, structure and methodology;
- ✓ Chapter 2 presents a summary of the main findings of the Tasks 2 & 3 report, and discusses its policy implications;
- ✓ Chapter 3 identifies barriers for the deployment and utilisation of flexibility sources in the Energy Community region;
- ✓ Chapter 4 provides a policy and regulatory recommendation toolbox for fostering flexibility sources in the Energy Community;
- ✓ Chapter 5 provides detailed information per Contracting Party, summarising the flexibility needs, flexibility contributions and investment needs for the different sources in cost-efficient portfolios for different scenarios; followed by an overview of the main barriers and recommendations for utilisation and deployment of flexibility at Contracting Party level.

The analysis presented in this report found a number of barriers hindering the deployment and utilisation of flexibility sources:

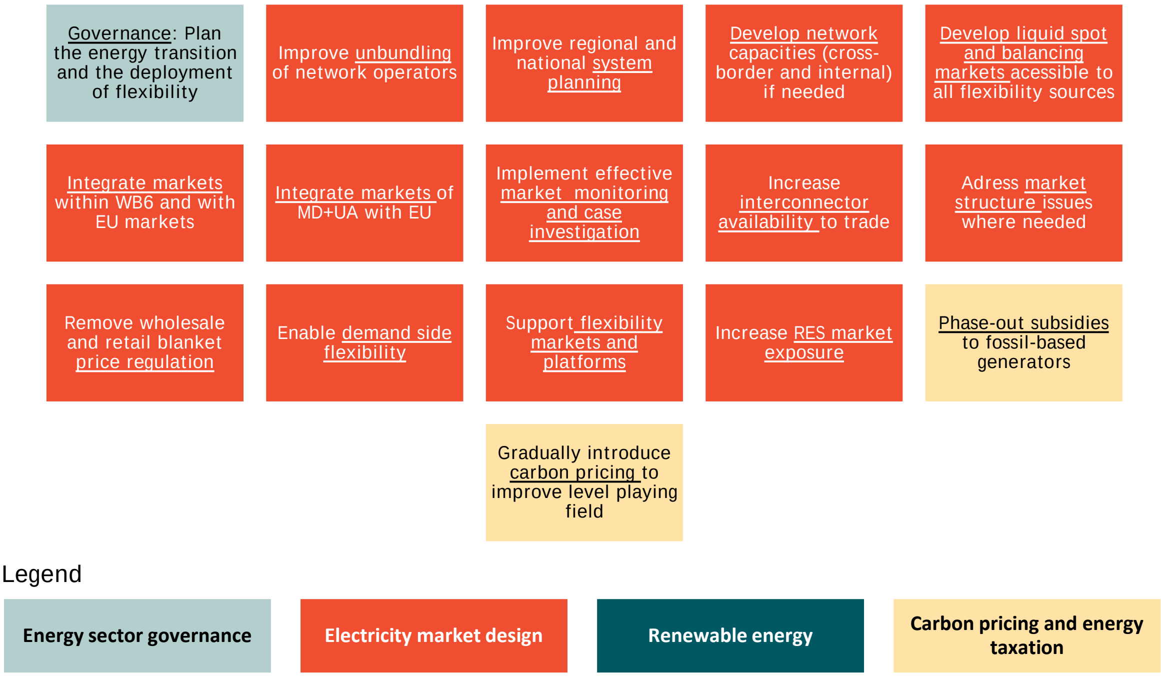
- While political ambitions regarding RES deployment and coal phase-out are increasing, uncertainty remains regarding the direction and speed of the transition.
- The lack of liquid, integrated spot (day-ahead, intraday) and balancing markets in most Contracting Parties hinders market access, in particular for new and small flexibility services providers, and hence leads to higher overall electricity system costs. Further, there is almost no cross-border market integration at this point, with explicit capacity allocation in some borders at most, and TSOs in general do not procure ancillary services yet (e.g. balancing capacity and energy) through cross-border auctions.

[1] Trinomics and Artelys (2021) Study on flexibility options to support decarbonization in the Energy Community - Task 1: Analysis of technical and non-technical sources of flexibility
[2] Artelys and Trinomics (2022) Study on flexibility options to support decarbonization in the Energy Community - Task 2&3

- While the ratio of nominal interconnector capacity versus domestic power generation capacity for Contracting Parties is in general higher than for most EU Member States, its availability for trading purposes is low, among others due to possible congestions in national transmission networks. At present, a high share of the interconnection capacity is unused due to different reasons out of scope of this report; the remaining capacity made available to the market is hence low and reduces the possibility of cross-border trade of flexibility sources.
- Generally, retail electricity markets are still highly concentrated, with few suppliers to choose from and with regulated prices and network tariffs in several CPs and no large-scale roll out of smart meters. This hampers the development of a competitive retail market and the active market participation of retail consumers and prosumers via local means including storage and demand response and other forms of demand side flexibility. The policies and markets do not yet provide adequate incentives (e.g. economic signals via market based electricity prices and time-of-use network tariffs) and instruments (e.g. smart meters, access to markets via aggregators) for the development of distributed flexibility.
- Other barriers, particularly coal subsidies for power generation (including through coal/lignite mining subsidies), administratively-set (i.e. not market-based) support for renewable energy based electricity and general lack of RES market exposure further reduce the competitiveness of non-subsidised flexibility sources by distorting the market, disincentivising renewable energy producer to reduce system flexibility needs, and ultimately leading to an inefficient selection of flexibility options.

The study developed a high-level set of policy and regulatory recommendations for fostering flexibility sources in the Contracting Parties. While there are differences in the individual regulatory frameworks, electricity systems and flexibility needs of the Contracting Parties, the EU energy acquis presents the blueprint for providing a level playing field for flexibility solutions across the Energy Community. Therefore, the study presents a set of measures which every Contracting Party should implement, with the EU acquis as a basis.

The figure below presents the main cross-Contracting Party recommendations for fostering flexibility sources. As can be seen, the majority of the recommendations relate to electricity market design aspects (which here include system planning aspects). As such, a main priority of Contracting Parties should be the creation of organised spot (day-ahead and intra-day) markets. Competitive (and cross-border where appropriate) procurement of ancillary services including balancing and congestion management services through market-based mechanisms as far as possible should complement the creation and integration of liquid spot markets.



Finally, the report concludes by providing, for each Contracting Party:

- The main existing flexibility sources;
- The Tasks 2 & 3 summary of modelling results with regards to the flexibility needs, flexibility contributions and investment needs in 2030 and 2040 for the baseline and ambitious scenarios;
- An overview of the current state of play and main barriers (with a detailed barrier assessment included in the annex); and
- Specific recommendations for optimal utilisation and deployment of flexibility sources.

1 Introduction

Objective and scope

The aim of this report is to provide recommendations to enable 1) the efficient utilisation of flexibility sources in the Energy Community region and 2) develop additional flexibility sources in order to meet future flexibility needs while assuring security of supply standards.

Structure of this report

The first section of the report provides an overview of the flexibility needs and sources in the Energy Community, building on the results from previous tasks of this assignment (chapter 2). This is followed by an analysis of the main barriers for deployment and utilisation of flexibility sources in the Energy Community (chapter 3). Chapter 4 concludes by providing an overarching set of measures which foster flexibility. A similar assessment is then provided in chapter 5 at Contracting Party level, providing an overview of the needs and sources of flexibility, current context and barriers for flexibility sources, followed by specific recommendations per Contracting Party.

Methodology

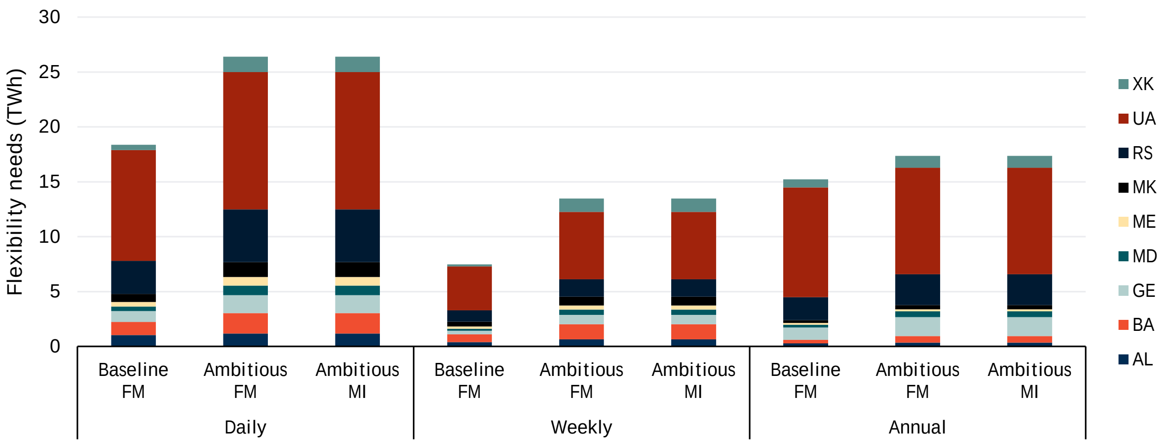
The approach for the study is differentiated according to the three main blocks of chapters:

- ✓ The needs and sources of flexibility presented in chapter 2 brings in the results from the literature review regarding flexibility sources along with those from the modelling exercise regarding flexibility needs.
- ✓ The analysis of barriers of chapter 3 is centred on the development of a survey on the flexibility barriers per Contracting Party, which was pre-filled in by the project team, completed by contact points at each Contracting Party and reviewed by the Energy Community Secretariat. The results of the survey are presented in the Annex.
- ✓ Finally, we have prepared the recommendations, bringing all the previous information together.

2 Policy implications of identified needs and sources of flexibility in the Contracting Parties

This section summarises the findings of the Tasks 2 & 3 report[3] assessing the flexibility needs and main sources in the Contracting Parties which are most relevant to the policy recommendations. Figure 2-1 presents the 2040 flexibility needs in the Contracting Parties across timeframes for different scenarios as calculated in Task 3. Further information on flexibility needs, contributions from the different sources and investments to 2030 and 2040 per Contracting Party is provided in chapter 5.

Figure 2-1 2040 flexibility needs in the Contracting Parties across timeframes for different scenarios



** Note the Ambitious Market Integration scenario does not exist for Georgia as only one projection of interconnection capacity was employed. Flexibility needs shown are from the Ambitious Fragmented Market scenario.*

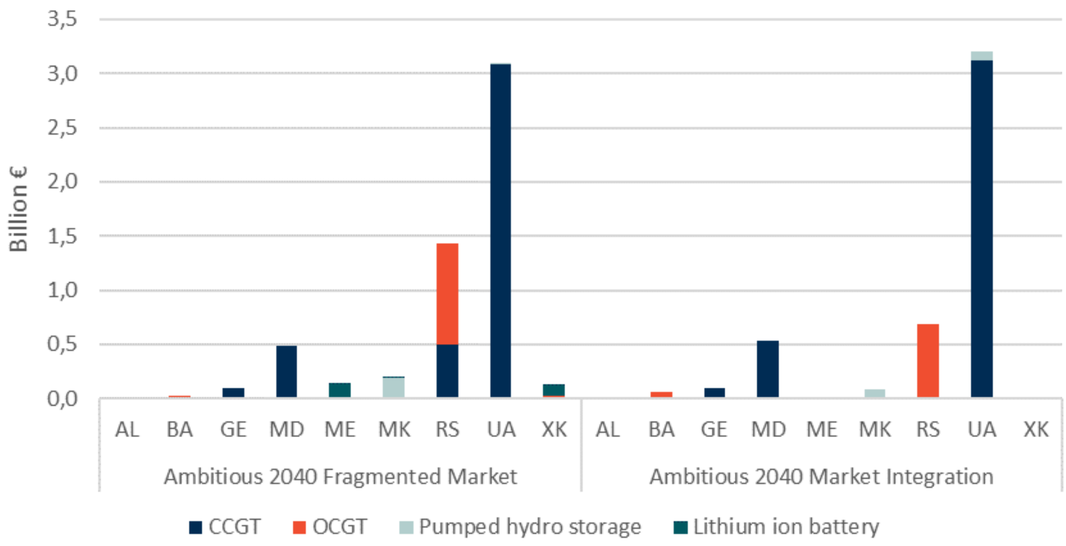
The Tasks 2 & 3 analysis shows that flexibility needs will increase to 2030 and 2040 across all timeframes (daily, weekly and annual), driven by the increasing penetration of renewable electricity sources. Increased renewable electricity penetration (related to more ambitious energy and climate targets) would impact especially daily and weekly flexibility needs, which will increase more strongly than annual flexibility needs, as the complementary seasonal profiles of solar PV and wind generation counterbalance each other to a certain extent.

The Tasks 2 & 3 analysis indicates that while coal, lignite and to a lower extent gas-fired power generation assets are currently important sources of flexibility, the decommissioning of the majority of these assets will significantly reduce their flexibility contributions to 2030 and 2040. It is forecasted that existing hydro and nuclear power plants will maintain their contributions to flexibility in the study horizon. Interconnectors (existing and new) become a more significant source of flexibility (to the extent that market coupling further allows cross-border exchange of flexibility in the future).

[3] Artelys & Trinomics (2022), Study on flexibility options to support decarbonization in the Energy Community: Task 2 - Evaluation of current flexibility sources utilized in the Contracting Parties & Task 3 - Evaluation of existing flexibility potential and future needs for additional flexibility in 2030 and in 2040, in each Contracting Party's power system.

Concerning new flexibility sources, the Tasks 2 & 3 report does not identify the need for investments in the 2030 horizon. Even in the 2040 horizon, investment needs are limited, with Contracting Parties differing significantly in the necessary investment volumes and technologies. Notable (above 1 GW) investment needs include CCGTs in Ukraine, OCTGs in Serbia, and Li-ion batteries in Montenegro. In the Ambitious scenario, investments in the order of 4.5-5.6 billion € to 2040 would be needed, albeit not evenly distributed between technologies and Contracting Parties, as shown in Figure 2-2. The total investments are reduced by 18% in the Market Integration scenario, compared to the Fragmented Market scenario. Moreover, electric vehicles would become a significant contributor of flexibility, although investment costs in electric vehicles were not explicitly considered. Investments are not needed to meet the flexibility needs in 2030 in any scenario, nor in 2040 in the baseline scenario.

Figure 2-2 Estimated investment in flexibility sources for the Contracting Parties



Note: the figure includes capital expenditures only, not fixed operating costs

Of the existing assets which are still in place in 2040 and new flexibility sources, the ones that most stand out are:

- ✓ For the Western Balkans 6, for the provision of daily flexibility, pumped and reservoir hydro, imports and, in the ambitious scenario, electric vehicles; for weekly flexibility, hydro reservoir and imports; and for annual flexibility lignite (in the baseline scenario), imports and CCGT (in more ambitious scenarios);
- ✓ For Ukraine and Moldova, for the provision of flexibility across all timeframes, interconnectors; for daily flexibility, nuclear, pumped and reservoir hydro, and electric vehicles; and for both weekly and annual flexibility, nuclear and CCGTs; and for annual flexibility, nuclear. In this timeframe, interconnectors can also be used to export flexibility in certain scenarios;
- ✓ For Georgia, for the provision of daily and weekly flexibility, hydro reservoirs; for annual flexibility, hydro reservoirs and CCGTs. We note that flexibility exchange through interconnectors was not modelled for Georgia, given it does not neighbour any Member State or Contracting Party.

Thus, under all scenarios, interconnectors play a significant role as a flexibility solution, by allowing countries (both Contracting Parties and Member States) to share flexibility sources. The Tasks 2 & 3 report also assesses the impact of increased system and market integration (represented by increased interconnectors' capacity to reflect their increased higher availability) on flexibility needs. The report finds that market integration decreases the need for flexibility from storage and thermal power generation.

The results of Tasks 2 & 3 have a number of consequences for the policy and regulatory recommendations to the Contracting Parties developed in this report:

- Wholesale electricity markets' design and functioning will be critical to provide a level playing field for flexibility sources: Flexible generation (gas-fired, nuclear and reservoir hydropower), pumped hydro storage, EVs and large-scale stationary batteries[4] will form the cornerstone of system flexibility in the Energy Community according to modelling results. Therefore, with the exception of EVs, all main flexibility sources will be large-scale front-of-the-meter ones directly participating in electricity markets. The provision of a level playing field in all electricity markets, including procurement of balancing capacity and energy by TSOs and between TSOs, will be key to incentivising existing sources to provide flexibility, and also important to incentivise investments in specific technologies in certain Contracting Parties;
- Market coupling between Contracting Parties and with the EU will play a large role in enabling the sharing of flexibility sources and maximising interconnector availability: In addition to national flexibility sources, interconnectors will play a crucial role in the exchange of flexibility, with Contracting Parties being (with some exceptions) net importers of flexibility originating from the EU. Cross-border exchanges will substantially reduce the required reserve and flexible capacity and reduce system costs;
- Retail market design and the provision of adequate price signals to demand response and prosumers (through both electricity prices and network tariffs) will likely be less important from a flexibility perspective. Nonetheless, the contributions to reducing flexibility needs and incentivising the participation of demand side flexibility in electricity markets remain relevant. Electric vehicle smart charging and vehicle-to-grid do appear as a significant flexibility source in the results of Tasks 2 & 3, even if actual deployment of smart/V2G-enabled EVs to 2040 in the Contracting Parties is uncertain. Tasks 2 & 3 did not model other demand-side assets such as industrial assets, heat pumps and electrolysers, which could therefore play a role to reducing flexibility needs and actively providing flexibility by 2040;
- The introduction of carbon pricing with the gradual phase-out of free CO_2 emissions allowances as well as of subsidies to coal/lignite-based generation are necessary in order to remove entry barriers to new flexibility sources, such as Li-ion batteries, pumped hydro and also gas-fired power generation;
- It is likely that additional flexibility sources will arise due to intra-hourly flexibility needs, which would increase the importance of measures for creating a liquid balancing market integrated between CPs and with the EU. Intra-hourly flexibility needs were not assessed in Tasks 2 & 3. Although many of the flexibility sources identified (such as gas-fired power generation, pumped hydro, Li-ion batteries, and smart charging of EVs/V2G) as well as

[4] Large-scale stationary batteries are relevant mainly for Montenegro and Kosovo* in 2040 where the renewable share is extremely high, in the fragmented market scenario.

flexibility sources not modelled are capable of providing intra-hourly flexibility, additional flexible capacity (from the same or new sources) would likely be needed.

3 Analysis of barriers for deployment and utilisation of flexibility sources in CPs

This chapter assesses the different barriers for deployment and utilisation of flexibility sources in the Contracting Parties. First, in section 3.1 a high-level description of barriers hampering flexibility in the Energy Community is presented. Then, as the context in each Contracting Party is different, section 3.2 provides an overview of the barriers per Contracting Party (detailed information is provided in Chapter 5 and in the annex). Finally, we conclude by assessing the main ways in which flexibility is hindered in the Energy Community.

3.1 Overview of barriers for deployment and utilisation of flexibility sources

We have grouped the barriers for deployment and utilisation of flexibility sources in those related to:

- Strategy;
- Regulation and market design;
- Market structure and performance;
- Electricity system planning and operation;
- Taxes and subsidies; and
- Technology specific barriers.

The following sections provide a short description the barriers comprised in each category.

3.1.1 Strategy-related barriers

In some CPs there is a lack of long-term planning for the energy system or a lack of policy strategy for the development of flexibility sources. For most CPs, there is a need to develop the NECPs and to consider system flexibility aspects in a much more integrated way in their NECP.[5] Further, there is a need to further improve the understanding of key stakeholders with regards to the future role and value of flexibility. Additionally, the lack of adequate RES production forecasting can also hinder the deployment and use of flexibility sources.

Addressing flexibility in the long term planning and energy strategy, reflects the political willingness of authorities to stimulate the development of flexibility sources which are considered necessary to ensure the reliability of the electricity system and to cost-efficiently succeed the energy transition. In the case of non-mature innovative technologies (such as smart EV charging and vehicle-to-grid), R&I support can accelerate the development and diffusion of the technologies and compensate for the development cost, in view of their large-scale deployment, cost reductions and performance gains in the medium or long term.

[5] For example, for Albania, the ECS recommends 'setting specific objectives and timelines on smart grids, aggregation, demand response, storage, distributed generation, mechanisms for dispatching, re-dispatching and curtailment, real-time price signals including the roll-out of intraday market coupling and cross-border balancing markets and non-discriminatory participation; consumers participation in the energy system and benefit from self-generation and new technologies, including smart meters, electricity system adequacy, as well as flexibility of the energy system with regard to renewable energy production, and grid congestions'.

3.1.2 Barriers related to regulation and market design

National energy authorities need to create an enabling legal and regulatory environment that gives all existing and new players in the energy market (including generators, storage operators and end-users) equal opportunity in providing flexibility to other market players and to transmission and distribution system operators. To enable small market operators (e.g. residential and small business consumers, prosumers and storage owners) to also value their flexibility potential, aggregators can play an essential role to offer this flexibility potential to the market or to network operators.

In this regard, there are key barriers to market entry related to the regulatory framework, such as the lack of (adequate) definition of prosumers, self-consumption and (independent) aggregators and their rights and obligations. In several CPs, there are no explicit definitions for prosumer or self-consumption and an adequate framework to enable demand response and the market participation of aggregators is often missing.

Cross-border integration of electricity markets (wholesale and ancillary services, especially balancing energy and reserve capacity) and efficient utilisation of cross-border infrastructure is paramount to making efficient use of flexibility resources across the Energy Community and achieving the energy and climate targets at least cost and without jeopardising energy supply security in the Contracting Parties. For flexibility sources to adequately play their role, markets have to enable efficient exchanges of energy to materialise, in particular on short timescales. As such, the absence of liquid day-ahead, intraday and balancing markets, the lack of market coupling, as well as the lack discriminatory procurement or mandatory (non-remunerated) provision of ancillary services are important barriers towards the efficient use of flexibility sources.

Textbox 3-1 Clarification on balancing markets

Balancing is done at different stages and via different instruments :

- BRPs balance their portfolio in the DA time window (their nominations must be in balance) and use the DA market to this end
- BRPs adjust (balance) their position, using the ID spot market to this end
- TSOs address residual imbalances via balancing contracts (capacity and energy), and charge balancing responsible parties for their imbalances

Flexibility resources are traded in all three timeframes in order for market parties and TSOs to address primary and residual imbalances, respectively. However, when mentioning the balancing market, we refer in this report to the procurement of balancing reserves and energy by TSOs.

The EU and Energy Community Contracting Parties aim for an increasing level of regional integration of forward, day-ahead, intraday/ spot and balancing markets[6], the integrated management of congestion, as well as to the achievement of energy & climate targets which will be set in the NECPs. This is an arduous challenge given the complexity of these markets and differences in their design and status of implementation between Contracting Parties, but a necessary step towards a resilient and climate-friendly energy system, given the increasing deployment of (grid-scale and distributed) renewable energy sources as well as the potential for provision of flexibility from sources across the electricity and

[6] Some of these ancillary services are: Balancing capacity and energy for frequency regulation: frequency containment reserve (FCR), manual and automatic frequency restoration reserve (mFRR and aFRR) and replacement reserve (RR); Voltage regulation; Black start capacity; Redispatch. Ancillary services help guarantee the reliability of the electricity systems.

broader energy value chain, from dispatchable power generation to storage and demand response, both large- and small-scale.

Additionally, for some CPs, RES remains exempt from balancing responsibility, excluded from the balancing mechanisms and there is insufficient motivation of RES producers to forecast their production. For example, currently there are discussions in Serbia where RES producers should be balanced by the universal supplier until intraday market is organized, according to the RES Law from 2021. There are disputes regarding how to proceed with the governmental decree that is in preparation which puts balancing responsibility on them. Contrary, WPPs producers in BiH are responsible for imbalances which takes much of their profit since they do not have competitive providers of the balancing energy and they are forced to pay a large amount of money to be balanced.

End-user electricity prices for household and other small consumers are explicitly or implicitly regulated in most CPs. End-user prices should incentivise a consumer's participation in providing flexibility as well as in reducing the system's flexibility needs; however, regulated prices (especially when set below actual marginal costs) do not give the right price signal to end-users to increase energy efficiency, encourage demand response nor to actively provide flexibility.

Temporally varying electricity price signals are important to activate demand side flexibility, as prices are comprehensible signals that can motivate end-users to participate in the flexibility market.[7] The lack of time-differentiated prices to energy consumers represents a barrier towards the deployment and utilisation of flexibility sources.

Currently, the lack of adequate carbon pricing in the Contracting Parties means that the negative externalities of fossil fuel-based generation are not internalised. The potential implementation of a carbon-border adjustment mechanism (CBAM) by the EU could have an important impact on the exchanges of electricity between CPs and EU Member States, and on the speed of the phase-out of fossil fuel based power generation in the Contracting Parties due to their lower level of competitiveness in case a CBAM is implemented.

3.1.3 Barriers related to market structure and performance

Some non-technical barriers to flexibility exist in the CPs as a consequence of their electricity markets' structure and performance. One barrier is the lack of, or non-compliant TSO or DSO unbundling in many CPs. According to best practices in electricity sector regulation, the separation of non-competitive activities (like transmission and distribution) from competitive ones (like generation, trade and retail) is essential to ensure transparent and non-discriminatory system planning, network access and procurement of ancillary services, and thus achieve optimal system efficiency and social welfare to customers.

Relating to the above mentioned welfare and competition issues, highly concentrated electricity wholesale markets or vertically integrated utilities also present a barrier in many CPs. If only one or two players dominate the market, there is in general low liquidity, especially if those players are vertically integrated and thus do not trade on organised markets to meet their energy needs. This leads

[7] Pressmair, G. et al (2021), Overcoming barriers for the adoption of Local Energy and Flexibility Markets: A user-centric and hybrid model. Journal of Cleaner Production. Volume 317, 1 October 2021, 128323.

to entry barriers for new or small participants that need a liquid spot market to trade and balance their positions, and which could otherwise provide significant flexibility.

3.1.4 Barriers related to electricity system planning and operation

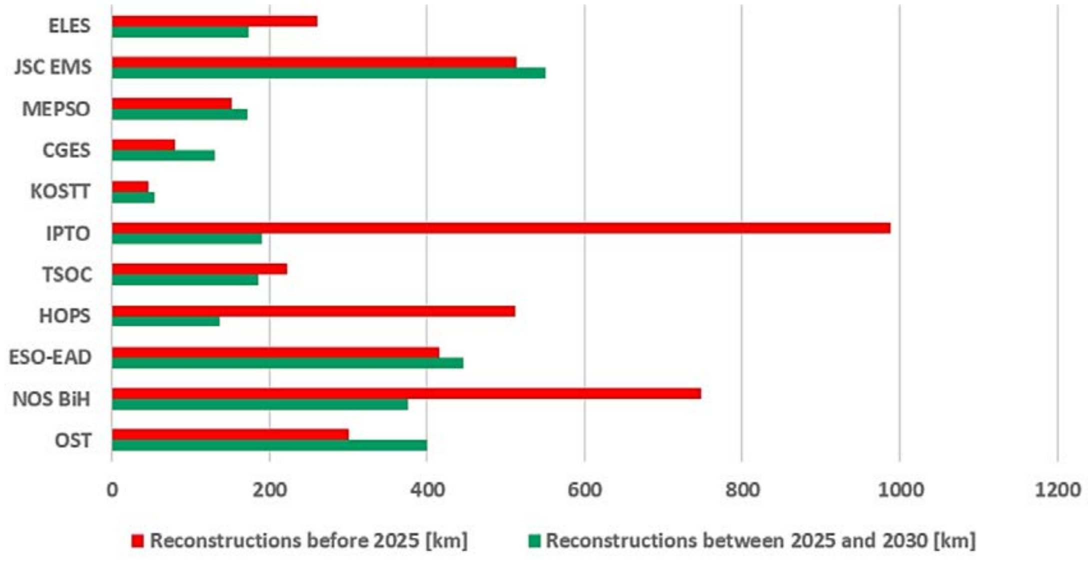
The exchanges of electricity between neighbouring countries can be a key provider of flexibility, complementing domestic resources such as dispatchable power generation assets, storage solutions, and demand side flexibility. First, the structure and profile of the demand differs to various extents between countries, with peaks occurring at different times in different areas. Second, solar PV availability and wind regimes are not perfectly correlated across Europe. Thus, regional and even pan-European market integration can reduce the variability of generation and demand profiles, thus reducing system flexibility needs.[8]

For interconnectors between Contracting Parties and with EU Member States to play their role in the provision of flexibility, several barriers need to be addressed. These entail in particular insufficient physical interconnector capacity (requiring in a few cases further development of cross-border capacities), and most importantly the fact that existing interconnector capacity are not (sufficiently) made available to the market, in most cases remaining below the 70% target to be transposed in the Energy Community acquis, which prevents optimisation of flexibility reservation and use at supra-national level. Whilst the report on the Electricity Interconnection Targets in the Energy Community Contracting Parties recognises that Contracting Parties are generally well interconnected (e.g. in terms of nominal interconnection capacity compared to peak load), the effective level of net transfer capacity is well below the nominal capacity, or e.g. in the case of KS-SR even non-existent. This difference is mainly due to bottlenecks in national transmission networks. In some CPs, in the absence of network expansion domestic transmission constraints are expected to hinder the integration of significant volumes of renewable electricity. Also, for most Contracting Parties interconnector availability for trade is well below 70%.

Internal transmission networks are expected to also need significant refurbishments. ENTSO-E indicates that several Western Balkans TSOs (such as JSC EMS in Serbia) have significant plans for reconstruction of transmission lines under 220 kV (which are often operated significantly beyond their originally planned lifetime) as shown in the figure below. Inadequate grid maintenance could significantly compromise security of supply and the ability to integrate renewable energy sources.[9] The need for reconstruction of internal networks will also lead to significant financing needs for several TSOs.

[8] Artelys (2018), Design of flexibility portfolios at Member State level to facilitate a cost-efficient integration of high shares of renewables
[9] ENTSO-E (2021) Regional Investment Plan - Continental South East

Figure 3-1 Reconstructions of 220 kV lines in the Continental South East Region[10]



Currently, the TSOs of the Western Balkans Contracting Parties are members of ENTSO-E and participate in the TYNDP drafting process, with the exception of the TSO from Kosovo*. However, the TSOs from Ukraine[11], Moldova and Georgia are not yet participating in this joint planning process. This leads to projects in and with these countries not being identified nor assessed in the TYNDP, and thus to difficulties when drafting the lists of Project of Energy Community Interest (PECI) and Projects of Mutual Interest (PMI).[12] More broadly, the lack of participation of all TSOs in the TYNDP process hinders efficient cooperation for the development of cross-border and internal projects of interest to the Energy Community, given that not only PECIs and PMIs may be of interest to share flexibility across Europe, but also other projects listed in the TYNDP. Currently, priority electricity infrastructure projects are documented across a number of different initiatives.[13]

As the boundaries become increasingly blurred between generators and consumers due to the emergence of active consumers[14], issues with cost allocation and inadequate network tariff design (especially for distribution, but also transmission in the case of large commercial and industrial active consumers) represent a barrier towards the deployment and utilisation of flexibility sources, too[15]. If tariffs are not set appropriately to reflect economic signals, consumers don’t have an incentive to contribute to system flexibility through demand response. The right network tariff design could ensure non-discriminatory access to the network and provide price signals to consumers adjusting their injection and demand patterns. For example, time-of-use tariffs could provide such signals, and flexible connection contracts (where network operators are entitled to curtail injections or withdrawal from the

[10] ENTSO-E (2021) Regional Investment Plan - Continental South East
[11] Ukraine became an Observer Member of ENTSO-E on 26 April 2022 after the emergency synchronisation of its electricity system with continental Europe
[12] Energy Community Secretariat (2018) Regional Infrastructure Development Coordination - Infrastructure planning process – from national to regional
[13] TYNDP, Project of Energy Community Interest (PECI) and Projects of Mutual Interest (PMI) lists, Projects of Eastern Partnership Interest (PEPI), and CESEC electricity action plan
[14] Prosumers are generally defined as electricity consumers that produce part of their electricity needs from their own power plant and use the distribution network to inject excess production and to withdraw electricity when self-production is not sufficient to meet own needs.
[15] Eurelectric (2021): Efficient network tariffs: a must for the energy transition (Efficient network tariffs: a must for the energy transition - Eurelectric – Powering People)

network in specified cases, with or without compensation to the network users) are also increasingly employed as a solution to connect new users in highly congested networks.

Smart electricity meters and smart systems are key to unlocking demand side flexibility by shifting loads depending on the grid (reduce peak load to avoid congestion) and market situation. Smart metering is a pre-condition for the development of behind-the-meter flexibility sources, enabling such development in combination with other factors such as the availability of dynamic supply tariffs and time-differentiated network tariffs. Demand-side flexibility sources enabled by smart meters include storage (stationary and mobile, i.e. EV smart charging but also vehicle-to-grid) and other forms of demand response than EV smart charging. The current lack of smart metering for end-users is therefore a barrier for demand response and other demand side flexibility. Roll out of smart electricity meters is taking place in the European Union and is expected to reach 77% penetration among consumers by 2024 in the EU.[16] However, large-scale roll out of smart meters is not yet planned in the CPs (except for Montenegro, which has a significant amount of smart meters).

Even though a well-developed grid infrastructure is essential to enable deployment of distribution power generation and electrification of energy demand, in some cases (such as to address non-structural congestions) the consideration of non-wire alternatives (i.e. other than network expansion) to address grid capacity constraints can be cheaper for network operators, even if they have to remunerate the flexibility provision at market-based conditions. However, in many CPs there is a lack of requirements and incentives for network operators to consider flexibility as alternative for investment in grid capacity. Flexibility sources like e.g. demand response and storage should more systematically be considered during the preparation and approval of network development and investments plans. Proper regulation should avoid that network operators have a bias towards network investments (also called *capex bias*) due to their revenue structure.

3.1.5 Barriers related to taxes and subsidies

Inadequate or high taxation of flexibility sources, such as the electricity generation or consumption tax and/or other levies which exist in all CPs, may negatively affect flexibility sources. For example, storage plants that are directly connected to the grid, may be considered as a consumer (offtake), with subsequently the discharged energy being taxed again when consumed by end-users, thus leading to double taxation[17]. This situation has a negative impact on investments and use of storage. [18] It must be noted that as double taxation occurs during storage offtake and then again during the final energy consumption, it differs from double tariff charging, which takes place when storage charges and then discharges. Storage can be subject to exemptions from or reductions of taxes and other levies which may be specific per voltage level (transmission or distribution), storage technology or application, and thus not fully adequate as they may discriminate against or in favour certain storage assets. In the case of VAT, such issue would be applicable only to natural persons re-selling stored energy, as business are generally able to recover VAT paid on inputs. Moreover, as taxes and levies represent a significant portion of final energy prices, they play a significant role in promoting a level playing field between

[16] European Commission, Smart grids and meters (2021) https://energy.ec.europa.eu/topics/markets-and-consumers/smart-grids-and-meters_en

[17] Double taxation occurs if storage is considered an energy consumer for taxation purposes where energy offtake by storage will constitute a taxable event and, subsequently, the discharge energy will be taxed once again when finally consumed by the end-user.

[18] European Commission, Directorate-General for Energy, Andrey, C., Barberi, P., Nuffel, L., et al., Study on energy storage : contribution to the security of the electricity supply in Europe, Publications Office, 2020, https://data.europa.eu/doi/10.2833/077257

energy carriers and, if desired, incentivising energy efficiency (by promoting direct use of electricity instead of other carriers, for example), renewable energy or innovative energy technologies - as long as this is compatible with State Aid Guidelines.

Direct subsidisation of fossil fuel-based or other power generation (e.g. coal or lignite) also affects the competitiveness of flexibility sources - and without carbon pricing even so. Most Contracting Parties provided direct subsidies to electricity generation from coal/lignite during 2018 and 2019.[19] Moreover, while coal-fired power plants offer daily, weekly and annual flexibility, some coal-fired power plants, besides their high emission factor, cannot be ramped up or down quickly enough to be considered flexible in the intra-hour time-scale, and may actually increase system flexibility needs.

Other types of market distortions can arise due to support scheme design. Most Contracting Parties have some kind of support scheme in place for renewable energy technologies (e.g. net metering or FiT/FiPs). Also, support for large-scale renewables installation may also exist. These support schemes have different levels of market-integration of the supported renewable energy. A lack of market-based support schemes for renewable energy can disincentivise renewable energy producers of reducing system flexibility needs.

3.1.6 *Technology-specific barriers*

Finally, there are technology-specific barriers that may have an impact on the deployment and use of flexibility sources.

For example, in some CPs, the regulatory framework does not allow the participation of demand response in the provision of balancing and other ancillary services, not making it possible for demand response to be actively engaged in market activities. Further, aspects discussed above regarding regulated prices (even set below production costs), lack of time-differentiated network tariffs and/or retail prices and lack of smart meters also act as important barriers towards demand response.

Similarly, for electric vehicle smart charging and vehicle-to-grid the different e-mobility aspects (including recharging infrastructure) are not yet properly defined and considered in the regulatory frameworks in several CPs. In Albania, for example, the policies on e-mobility are not linked to those on demand side management and electricity storage systems for grid flexibility.

Regarding energy storage, there is still work to be done in the regulatory frameworks in some CPs, where there are no legislative provisions in this regard or where legislation has not specified types of storage facilities.

Regarding gas-fired power generation, several CPs that rely on Russian gas imports have underdeveloped gas markets and miss necessary gas infrastructure to enable alternative gas supply sources and routes. Given the Russian invasion of Ukraine in February 2022, alternative supply routes and changes in gas-fired capacity are needed and can be expected in some CPs. The lack of virtual reverse gas flows also hinder flexibility. Currently, the Energy Community Secretariat has an open case against Moldova for lack of virtual reverse gas flow.

[19] Energy Community (2020), Investments into the past: An analysis of Direct Subsidies to Coal and Lignite Electricity Production in the Energy Community Contracting Parties 2018-2019

Regarding other existing power plants, in particular the hydro power plants in Albania, BiH and Serbia, less favourable (due to climate change) hydrological conditions may limit their production, including their potential provision of flexibility services. This may occur on an annual level, but also seasonally, especially during summer months. Further, several CPs rely on coal-fired power plants which are currently not operated in a flexible manner.

3.2 Characterisation of barriers per CP

The following sections provide a short overview of the main barriers per contracting party. An overview of the barrier assessment per CP is presented in the table below while additional detailed information per CP is included in the Annex.

Table 3-1 Overview of barriers per CP

Aspect	Barrier	Albania	BiH	Georgia	Kosovo	Moldova	Montenegro	North Macedonia	Serbia	Ukraine
Strategy	Lack of long-term planning for the development of flexibility sources	P	Y	P	P	P	P	N	P	P
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	P	P	P	N	P	N	Y	N	N
	Aggregators not defined in regulatory framework	Y	Y	Y	Y	-	Y	P	N	Y
	Absence / issues with Day-ahead market	Y	Y	Y	Y	Y	Y	Y	N	P
	Absence / issues with Intra-day market	Y	P	Y	P	Y	Y	Y	P	P
	Absence / issues with balancing market	N	P	Y	P	Y	N	N	Y	P
	Absence of DA/ID market coupling and/or cross-border balancing	Y	Y	Y	Y	Y	Y	P	Y	Y
	Price caps and other restrictions on wholesale markets	-	-	-	-	-	-	P	P	Y
	End-user price regulation / other interventions	P	Y	Y	Y	Y	P	Y	Y	Y
	Lack of time-differentiated retail commodity prices	P	-	Y	P	-	N	P	N	N
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	P	P	P	N	P	N	N	P[20]	N
	Electricity wholesale market concentration	Y	Y	P	Y	Y	Y	P	Y	Y
	Limited/no competition in electricity retail markets	Y	Y	Y	Y	Y	Y	Y	Y	P
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use	N	N	P	N	N	N	N	N	P
	Existing interconnector capacity is not (sufficiently) available to the market	Y	P	Y	Y	Y	P	Y	Y	Y
	Other network capacity, capacity allocation and congestion management issues	-	N	P	P	P	-	N	P	P
	Inadequate network tariff design	Y	N	Y	Y	Y	N	Y	N	Y
	Lack of smart metering for low voltage-connected users	P	P	N	P	N	N	Y	Y	P
	Lack of incentives for network operators to consider non-wire alternatives	Y	-	Y	Y	-	N	N	-	Y
Taxes and subsidies	Inadequate / high taxation of flexibility sources	-	Y	-	N	-	N	N	Y	-
	Subsidisation of fossil-based / other power generation	N	Y	-	Y	-	Y	Y	Y	Y
	Insufficient market integration of (large-scale) RES	P	P	P	N	P	P	N	N	P
Technology-specific barriers	Other barriers to demand response	Y	Y	Y	P	Y	N	Y	N	Y
	Other barriers to gas-fired generation	N	P	-	Y	Y	Y	Y	-	N
	Other barriers to EV smart charging / vehicle-to-grid	P	P	P	Y	P	Y	P	P	P
	Other barriers to Storage (front / behind-the-meter)	-	-	Y	Y	-	-	-	N	N
	Barriers to other technologies / existing power plants	Y	Y	-	Y	Y	-	Y	Y	Y

Legend: Y: Yes, N: No, P: Partially a barrier, -: Not applicable

[20] See section 5.8 for further details

3.3 Impact of barriers on different flexibility sources

The following table provides an overview of which flexibility sources are impacted by the listed barriers. From this summary, on one hand it can be seen that the regulation and market design aspects, in particular the absence or issues with national day-ahead, intraday and balancing markets have an impact in the deployment and utilisation of all flexibility sources, and as such should be a priority when developing the recommendations. Further, aspects such as lack of market integration and TSO/DSO unbundling also impact all flexibility sources.

In terms of improving the efficient utilisation of flexibility sources across the region through market integration, the main barriers are insufficient availability of interconnector capacity to the market, along with related internal network congestion issues.

On the other hand, several other barriers affect only demand side flexibility (i.e. industrial and residential demand response, as well as EV smart charging and V2G). These include the lack of an adequate regulatory framework which defines aggregators and prosumers; and lack of adequate price signals to consumers (due to e.g. price regulation and lack of time-differentiated prices and network tariffs – which in turn are hindered by the lack of smart meter roll-out).

Table 3-2 Main sources of flexibility hindered by the identified barriers

Aspect	Barrier	Coal	Lignite	OCGT	CCGT	Biomass	Nuclear	PHS	Hydro reservoir	Li-ion battery	Electric vehicles	DSMDR	Inter-connectors
Strategy	Lack of long-term planning for the development of flexibility sources	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework									✓	✓	✓	
	Aggregators not defined in regulatory framework									✓	✓	✓	
	Absence / issues with Day-ahead and Intra-day market	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Absence / issues with balancing markets	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Absence of DA/ID market coupling and/or cross-border balancing	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Price caps and other restrictions on wholesale markets			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	End-user price regulation / other interventions									✓	✓	✓	
	Lack of time-differentiated retail commodity prices									✓	✓	✓	
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling			✓	✓	✓	✓	✓	✓	✓	✓	✓	
	Electricity wholesale market concentration			✓	✓	✓		✓	✓	✓	✓	✓	
	Limited/no competition in electricity retail markets										✓	✓	
Network services and operations	Insufficient interconnector capacity and/or capacity available to the market			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Other network capacity, capacity allocation and congestion management issues			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Inadequate network tariff design							✓		✓	✓	✓	
	Lack of smart metering for low voltage-connected users										✓	✓	
	Lack of incentives for network operators to consider non-wire alternatives									✓	✓	✓	
Taxes and subsidies	Inadequate / high taxation of flexibility sources							✓	✓	✓	✓	✓	
	Subsidisation of fossil-based / other power generation					✓		✓	✓	✓	✓	✓	
	Insufficient market integration of (large-scale) RES			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Technology-specific barriers	Other barriers to demand response									✓	✓	✓	
	Other barriers to gas-fired generation			✓	✓								
	Other barriers to EV smart charging / vehicle-to-grid										✓		
	Other barriers to Storage (front / behind-the-meter)							✓	✓	✓	✓		
	Barriers to other technologies / existing power plants	✓	✓	✓	✓	✓	✓		✓				

3.4 Conclusions

While ambitions regarding RES deployment and coal phase-out are increasing, uncertainty remains

The incorporation of the Clean Energy Package into the Energy Community acquis and the adoption of the Energy Community Decarbonisation Roadmap are driving the shift from coal fired power generation to more renewable energy deployment.[21] However, there is a lack of structured energy transition plans in many CPs, including the National Energy and Climate Plans that are still in development, which leads to uncertainty regarding the direction and speed of the transition.[22]

The lack of liquid, integrated spot and balancing markets hinders cost-efficient use of flexibility sources

While wholesale markets are developed to some extent, most CPs have not yet established organised spot (day-ahead and intraday) nor balancing markets, and the spot markets that exist generally have low liquidity. There is also significant concentration in generation at the existing organised markets. Further, currently spot markets are integrated only with explicit capacity allocation, there is limited exchange of balancing energy, and TSOs do not procure ancillary services yet (e.g. balancing capacity and energy) through cross-border auctions. The lack of functioning wholesale spot and balancing markets and their cross-border integration hinders the effective utilisation of flexibility sources. Additionally, RES is excluded from the balancing mechanisms and there is insufficient motivation of RES producers to forecast their production.

While nominal interconnector capacity is in general higher than for EU Member States, its availability for trading purposes is low

While most Contracting Parties are generally well interconnected (e.g. in terms of nominal interconnection capacity compared to national installed generation capacity and their peak load), the effective level of net transfer capacity is well below the physical cross-border lines limitations, among others due to congestion in national transmission networks. In particular, existing interconnector capacity is often not (sufficiently) made available to the market which may restrict the possibility of cross-border trade of flexibility sources. Cross border capacity calculation methodologies are still not harmonized among TSOs of the region, which contributes to the problem.[23] Internal transmission networks in the Western Balkans are also in need of significant refurbishment, especially the oldest lines 110 kV and 220 kV.

Generally, retail markets are still highly concentrated, with regulated prices and network tariffs that do not provide adequate incentives for development of distributed flexibility

In most CPs there is still a high retail market concentration[24] with few suppliers to choose from, which leads to lack of competitive pressure that represent barriers to the development of a competitive retail market and the active market participation of retail consumers and prosumers via demand response and other forms of demand side flexibility, also due to the absence of smart metering in the low voltage market segment. Further, end-user electricity for household customers are still available at regulated

[21] https://balkangreenenergynews.com/energy-community-adopts-clean-energy-package-decarbonization-roadmap/
[22] ECS (2021), WB6 Energy Transition Tracker.
[23] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020
[24] In Albania, Bosnia and Herzegovina, North Macedonia, Serbia and Ukraine more than ten nationwide suppliers were active in the retail market, in Moldova there were seven active nationwide suppliers, while in the other Contracting Parties supply to electricity end-users was offered by one supplier. ECRB (2021), Market Monitoring Report: Gas and electricity retail markets in the Energy Community. Reporting period 2020.

prices in all Contracting Parties, except in Montenegro.[25] Thus, the markets at present do not yet provide adequate incentives for the development of distributed flexibility.

Other barriers, particularly coal subsidies and administratively-set (i.e. not market-based) renewables support further reduce the competitiveness of flexibility sources

Most CPs continue to provide direct subsidies for fossil fuel-based power generation (including through coal/lignite mining subsidies), which has a negative impact on the competitiveness of flexibility resources. In addition, the need for further market-based support schemes for renewable energy technologies (all except small-scale) can also distort the market and ultimately lead to an inefficient selection of flexibility options.

[25] ECRB (2021), Market Monitoring Report: Gas and electricity retail markets in the Energy Community. Reporting period 2020.

4 Policy and regulatory recommendations for fostering flexibility in the Energy Community

This chapter develops policy and regulatory recommendations for fostering flexibility options in the Contracting Parties. It provides a high-level set of measures for fostering flexibility in the Energy Community. This set of measures is largely based on the existing EU energy and climate acquis, and therefore is not tailored to each Contracting Party as it constitutes the target framework which is expected to be implemented in all Contracting Parties.[26] Then, as each Contracting Party is in practice at a different stage of implementation of the EU energy and climate acquis (and as they will have different flexibility needs as shown in Task 3 of this study), in Chapter 5 tailored recommendations for each Contracting Party are provided.

The EU energy acquis[27] defines common aspects that facilitate and improve the participation of flexibility sources in electricity markets. Several EU legal provisions define policies and measures which remove barriers for the participation of flexibility sources in electricity markets and promote a level-playing field between all different sources. Examples of such policies and measures include the large scale roll-out of smart metering (when cost-efficient), and the new provisions regarding storage and demand response introduced in the recast Electricity Directive and Regulation.

The Energy Community has incorporated much of the EU energy acquis into its own acquis, including most elements of the Clean Energy for All Europeans Package,[28] and is continuously updating the latter in order to ensure the increased and sustained alignment of the regulatory framework of the Contracting Parties with the EU's. While there are differences in the individual regulatory frameworks, electricity systems and flexibility needs of the Contracting Parties, the EU energy acquis, and thus the Energy Community acquis, still provide the blueprint for providing a level playing field for flexibility solutions across the Energy Community. Therefore, incorporation of the EU's energy acquis into the Energy Community's and its implementation is pivotal to fostering flexibility sources in the Contracting Parties.

As shown in the previous chapter, the implementation of the Energy Community acquis is still on-going in the different CPs, with differing levels of progress.[29] It must be noted that currently only political measures exist for sanctioning Contracting Parties for breaching their Treaty obligations.[30,31] This means in practice that CPs do not face any financial penalties for not implementing the Energy Community acquis, or even for adopting measures which are contrary to it.[32] The reform of the Energy Community

[26] Although not all EU legislation relevant to flexibility is covered in the current Energy Community Treaty, as discussed below
[27] References to the EU energy acquis or Energy Community acquis here include also environmental, climate and competition regulation legislation which is part of these acquis.
The acquis is here understood as including secondary legislation such as the electricity network codes and guidelines
[28] https://www.energy-community.org/news/Energy-Community-News/2021/11/30.html
[29] Energy Community Secretariat (2021) Annual Implementation Report
[30] That is, the Ministerial Council of the Energy Community may decide that a CP is in breach of its obligations. In theory, the Council could certain rights such as "suspension of voting rights and exclusion from meetings". Energy Community Treaty Title VII
[31] See for more details Buschle (2016) The enforcement of European energy law outside the European Union - Does the Energy Community live up to the expectations? Available at https://www.energy-community.org/dam/jcr:c9f03062-7963-4f6e-8179-2f4f6ff1656a/%20EEJ_Buschle_enforcement_EU_energy_law.pdf
[32] Energy Community Secretariat (2021) Annual Implementation Report

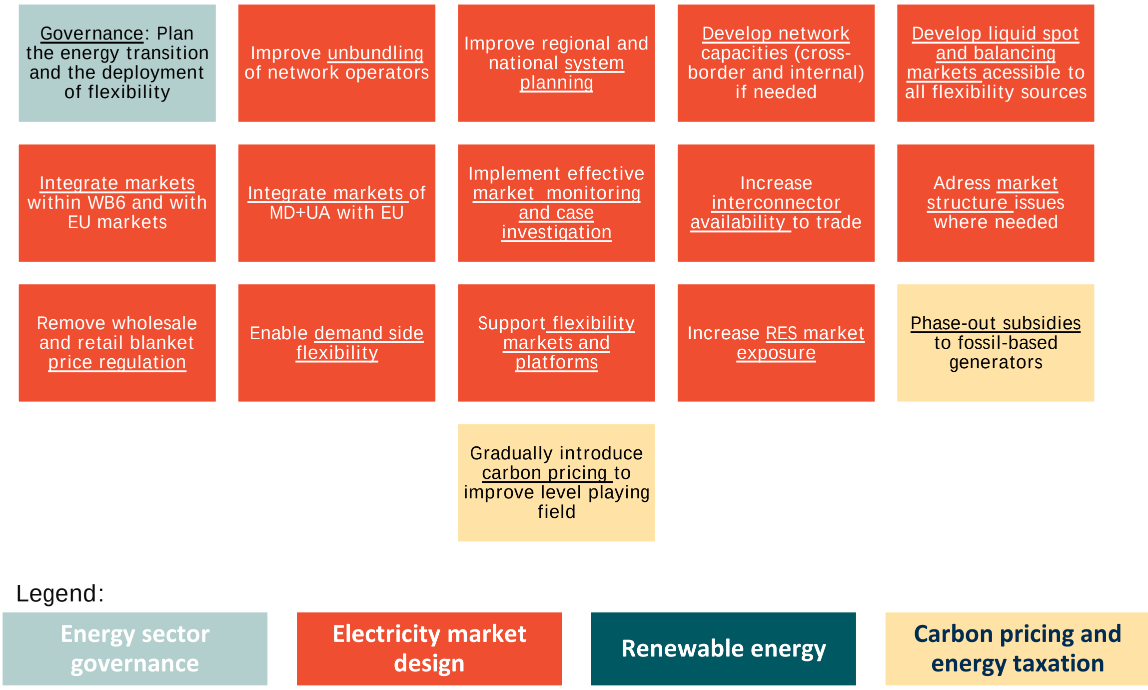
Treaty is however not analysed here as it concerns a larger topic which is out of scope of the present project.

This section therefore presents a set of measures for fostering flexibility in the Contracting Parties, with the Energy Community acquis as a basis (considering planned or necessary changes). The measures are separated in the following categories:

- ✓ Energy sector governance
- ✓ Electricity market design
- ✓ Renewable energy
- ✓ Carbon pricing and energy taxation

Figure 4-1 presents the main cross-Contracting Party recommendations for fostering flexibility sources. As can be seen, the majority of the recommendations relate to electricity market design aspects (which includes system planning aspects).

Figure 4-1 Main cross-CP recommendations for fostering flexibility sources



The analysis and examples provided in the sections below focus on the flexibility sources which were identified in the Tasks 2 & 3 report as making the main contributions in the 2030 and 2040 horizons.

We do not analyse in this report support schemes to facilitate the large-scale deployment of flexibility sources, as the policies and measures of the Contracting Parties should aim at providing a level-playing field for the participation of the flexibility sources in the different electricity market timeframes, coupling markets at the EnC and EU levels, and providing signals to market participants and consumers to take decisions which reduce the system flexibility needs. The most likely exception to this are Contracting Parties' subsidies to facilitate the deployment of electric vehicles, which could indirectly benefit the provision of system flexibility through smart charging and V2G. However, a detailed analysis of policies to foster EV deployment is out of scope of this report. Also, the analysis of Tasks 2 & 3 finds that coal and lignite-fired generation will still play some role in flexibility provision in 2040, especially in the baseline scenario. However, providing recommendations specific to those assets is not a particular focus of this report.

It is of utmost importance that all Contracting Parties adhere to their obligations regarding the implementation of the Energy Community acquis. This chapter however is focused on providing a holistic set of recommendations for Contracting Parties fostering flexibility in the long-term. Nonetheless, where relevant (especially for the efficient use of existing flexibility sources), current developments regarding the implementation of the acquis are also covered.

4.1 Energy sector governance

As shown in the Task 1 report[33], flexibility sources exist along the entire electricity value chain. Therefore, a regulatory framework to facilitate deployment of flexibility sources needs to address several regulatory aspects, which is not possible to do with individual legislative or regulatory pieces – instead, flexibility provision needs to be considered holistically. Therefore, appropriate energy sector governance which adequately considers flexibility is essential to ensure adequate flexibility levels and coordinate the changes across the regulatory framework. Moreover, appropriate governance is a pre-requisite to providing certainty for investors in flexibility sources. In this regard, it is important to note that the Energy Community Council is expected to formalise by the end of the year the decarbonisation targets of the Contracting Parties.

4.1.1 Develop National Energy and Climate Plans and Long-Term Strategies

National Energy and Climate Plans, their associated progress reports as well as Long-Term Strategies are key instruments to define national energy pathways and the required policies and measures to accomplish them. This is necessary in order to provide guidance to energy sector actors on the phase-out of fossil-based electricity generation, development of renewable energy sources, decarbonisation of end-uses and the associated deployment of new flexibility sources necessary. This especially as the implementation of the Energy Community acquis will lead to a greater complexity of the Contracting Parties’ energy systems and thus the need for coordination between market and regulated actors. While price volatility can be expected to increase in the Member States and Contracting Parties’ energy markets, which will serve to incentivise the deployment of new flexibility sources, uncoordinated entries and exits in the energy markets can lead to unwanted imbalances in the available supply and demand.[34] The flexibility needs and fostering of flexibility sources should be addressed especially under the National Energy and Climate Plan dimensions ‘internal energy market’ and ‘energy supply security’.

4.1.2 Develop a strategy on flexibility sources

The planning of policies and measures to foster flexibility sources can be undertaken through energy/electricity sector strategies (or strategies focusing on individual flexibility solution categories such as demand response or storage) in addition to through National Energy and Climate Plans. Several EU Member States have published energy storage or demand response strategies.[35] As strategies are more focused than overall plans, they may be more appropriate to first identify the necessary policies

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[33] Trinomics and Artelys (2021) Study on flexibility options to support decarbonization in the Energy Community - Task 1 Analysis of technical and non-technical sources of flexibility
[34] ACER (2022) ACER’s Final Assessment of the EU Wholesale Electricity Market Design
[35] For example Spain’s Storage Strategy https://www.miteco.gob.es/es/prensa/estrategiaalmacenamiento_tcm30-522655.pdf

and measures, which can then be incorporated into NECPs. Strategies can focus on specific aspects, such as system integration, storage or demand response. Given the diversity of flexibility sources, a global strategy focusing on flexibility in the power system may be warranted (as opposed to developing individual strategies on storage, demand response, etc). This may be part of a larger exercise on a strategy for the power or energy system. The flexibility strategy or the NECP may furthermore indicate clear targets for the deployment of specific (categories of) flexibility technologies, if appropriate and weighing the advantages of providing these targets vs that of only aiming to provide a level-playing field for all flexibility sources.

4.1.3 Ensure regulatory predictability

Contracting Parties should ensure regulatory predictability to provide adequate signals to investors. This does not mean that regulation should remain unchanged, but rather that any reforms should be consulted with stakeholders in a transparent manner, implemented gradually as far as possible and not unduly affect past investments.

In order to mitigate the consequences of the recent fossil fuel price increases affecting the whole of Europe, Contracting Parties have adopted measures which, while they can be justified if they are proportionate and temporary, may make the full implementation of the Energy Community acquis more difficult.[36] Moreover, recent measures[37] which contradict the Energy Community acquis highlight the importance of regulatory predictability in order to provide certainty to investors in flexibility sources - as mentioned by CEER.[38]

This is all the more important in the current context, where Member States and Contracting Parties alike implement emergency measures to address some of the effects of the current energy crisis, which is in essence a gas supply crisis that also affects electricity markets. These measures, if ill-designed, may interfere in price signals and market formation.[39] Contracting Parties should be careful when implementing emergency measures (by the regulator or policy makers), as they may complicate the implementation of the Energy Community acquis, reduce cost reflectivity and lead to cross-subsidies[40] in the energy sector, and negatively affect investments, all of which will hinder the deployment and efficient operation of flexibility sources.

The European Commission has in 2021 provided a toolbox of measures deemed compatible with state aid rules to deal with high energy prices[41] and in 2022 complemented the toolbox with further emergency measures that could be adopted by Member States.[42] These two communications could provide some guidance to Contracting Parties to address the high energy prices with as little distortion of the energy market as possible. However, the need for ensuring regulatory predictability goes beyond the measures taken by Contracting Parties' governments and regulators to address the energy crisis.

[36] Energy Community Secretariat (2021) Annual Implementation Report
[37] Most contracting parties have not changed prices to retail consumers. In addition, Albania, North Macedonia, Moldova and Serbia at least have introduced financial support to companies and/or consumers.
ECRB (2021) Impact of the electricity price surge in Energy Community Contracting Parties and measures undertaken
Balkan Green Energy News (2022) Energy crisis is not emergency but new reality - Trhulj.
https://balkangreenenergynews.com/energy-crisis-is-not-emergency-but-new-reality-trhulj/
[38] CEER (2021) Long-Term Generation Investment Signals in a Market with High Shares of Renewables
[39] ACER (2022) ACER's Final Assessment of the EU Wholesale Electricity Market Design
[40] Depending on how they are implemented, interventions such as blanket (i.e. not targeted only at protecting a restricted group such as vulnerable consumers) price regulation may represent cross-subsidies from energy producers, suppliers and network operators to end-consumers, negatively affecting cost recovery by the former.
[41] https://ec.europa.eu/commission/presscorner/detail/en/IP_21_5204
[42] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_3140

4.2 Electricity market design

4.2.1 *Ensure adequate separation between competitive and regulated activities*

In order to provide their services to other market operators or to TSOs/DSOs, owners/operators of flexibility sources need to have non-discriminatory access to electricity networks and markets. Regulated network operators play a critical role in planning electricity networks and providing connection and access to them for flexibility sources. They are also central to cross-border market integration, both by developing and making available sufficient interconnection capacity to the market, as well as by participating in the market coupling initiatives. Network operators are moreover responsible for the procurement of ancillary and congestion management services, which are an important source of revenues for owners/operators of flexibility sources. Flexibility sources used to avoid or reduce grid congestion may also be an alternative to grid reinforcement, and should be properly considered by network operators in their network plans. Finally, network operators may incentivise passive flexibility through appropriate tariff designs. TSOs and DSOs have hence an essential role in the deployment of flexibility sources, and compliant unbundling (combined with other measures) is necessary to ensure a non-discriminatory access of flexibility sources to networks. This applies especially to TSOs, but given the expected contribution of flexibility sources connected at the distribution level shown in the Tasks 2 & 3 report, unbundling of large DSOs is also important.

4.2.2 *Create and develop organised day-ahead, intra-day and balancing markets*

A main priority of Contracting Parties should be the creation of organised spot (day-ahead and intra-day) and balancing markets. As indicated in the Tasks 2 & 3 report, ambitious renewable energy deployment will lead to increases in flexibility needs especially in the daily (due to solar PV deployment) and weekly (due to wind deployment as well as workweek-weekend load patterns) timeframes. Spot and balancing markets will be critical for allowing market participants to adjust their positions in those timeframes (including intra-hourly) considering updated renewable energy generation forecasts (including demand response assets such as smart-charging EVs which will be relevant flexibility sources in some CPs by 2040), and for system operators to manage residual imbalances.

Annual (i.e. seasonal) flexibility needs should not be overlooked either, as they will also be significant and as shown in Task 1 report there are fewer available non-fossil-based sources for provision of flexibility in the annual than in the daily timeframes, especially in CPs with no reservoir-based hydropower potential. In this regard, liquid spot markets should provide the main reference price signals for long-term markets and for investment decisions by flexibility operators relying on these markets for part of their revenues. Multiple Contracting Parties (AL, GE, MD, ME, MK, XK) realised by June 2022 or planned for the same year the go-live of day-ahead and/or intra-day markets.[43]

Competitive procurement of ancillary services other than balancing and congestion management services (through organised markets where justified) should complement the creation of wholesale markets. The existence and liquidity of such markets and competitive procurement of ancillary and congestion management services are a prerequisite to provide price references as well as the market opportunities for potential flexibility providers to make investment decisions. In the absence of

[43] 27 th Energy Community Electricity Forum Conclusions. https://www.energy-community.org/dam/jcr:02dce2c2-4b89-4079-a299-db0f10607088/AF_conclusions_0622.pdf

adequate price signals, innovation in and deployment of new flexibility resources may be significantly impacted.[44] Given the current state in the Energy Community where most Contracting Parties do not have such markets in place, as shown in the previous chapter, the creation of an enabling regulatory framework and adequate rules and procedures, as well as the designation of a market operator should be a point of attention.

There is significant experience in removing entry barriers to small and new market participants in the EU (although some barriers still remain).[45] Contracting Parties should design organised electricity markets respecting the requirements of the EU electricity market design, such as regarding the removal of price caps, the acceptance of small bids, the possibility for aggregation, minimum and maximum delivery periods, and other aspects. This will not only facilitate the efficient utilisation of existing flexibility sources and provide a positive environment for the entry of new ones, but also facilitate the integration of electricity markets within the Energy Community and with the EU.

Also, Contracting Parties should pay attention, when designing market reforms, to on-going developments in the EU, in order to facilitate future markets integration (and make use of lessons learned). Specifically, future changes to the Capacity Allocation and Congestion Management Guideline should be considered, as they may affect the governance of the market coupling and the designation of Nominated Electricity Market Operators (with a single European market coupling entity being established).

The creation of organised markets may need to be coupled with various measures, especially to address market concentration and increase liquidity where needed (described below). Other measures such as technical assistance to qualify new participants may be needed.

4.2.3 Develop the market-based procurement of non-frequency ancillary and congestion management services

Taking into account the current state of spot and balancing markets, further progress is needed in the competitive procurement by TSOs of services such as voltage control, black start or islanded operation, and redispatch - both in the EU as well as in the Contracting Parties. While not as important as the development of spot and balancing markets, Contracting Parties should promote the market-based procurement of these services. This should be combined with real-time publication of system information (RES forecasts, imbalances,…), to guide market parties in their operational decisions.

System operators may also create mechanisms for procuring new ancillary services such as ramping up/down products, synchronous inertia and fast frequency response if and when needed as a result of an increasing penetration of intermittent renewable energy sources and the phase out of fossil-based synchronous generators. However, for continental Europe this is not expected to be necessary in the short-term, including for Contracting Parties.[46] The same can be said regarding local flexibility platforms and markets – while progress is being made on the development of distributed renewable energy in the Energy Community and Contracting Parties should implement the provisions of the electricity market design regarding local flexibility, distributed energy resources should not play a significant role for flexibility up to at least 2030 as shown in the Tasks 2 & 3 report.

[44] ACER's Final Assessment of the EU Wholesale Electricity Market Design
[45] ACER (2022) ACER Market Monitoring Report 2020 – Electricity Wholesale Market Volume.
[46] EU-SysFlex (2019) D2.4: Scarcity identification for Pan European System

The creation of spot and balancing markets, and the market-based procurement of non-frequency ancillary and congestion management services should provide the main sources of revenue to flexibility sources. Capacity remuneration mechanisms (CRM) may complement revenues, but CRM should only be introduced when duly justified based on an adequacy assessment, and when other means to ensure system adequacy are insufficient.

While existing flexibility sources should be able to readily make use of these different potential revenue streams, investors in new flexibility sources such as storage or demand response may face barriers to make the necessary investment decisions. For example, storage faces barriers related to monetising price volatility, technological uncertainty, as well as high CAPEX costs for several storage technologies.[47] Capacity remuneration mechanisms, when they exist, may make up only a small share of the storage operators' revenues.

However, the introduction of new mechanisms (including capacity remuneration mechanisms and new ancillary services) should first be demonstrated by clear system adequacy (security of supply) needs which cannot be met by existing mechanisms. Moreover, any new mechanism should be technology-neutral, not favouring specific sources of flexibility. We therefore recommend that Contracting Parties do not introduce specific support mechanisms for the large-scale deployment of specific flexibility sources such as storage or demand response. There is however room for mechanisms incentivising innovation and experimentation through pilot projects. These could also facilitate regulatory learning prior to adapting the regulatory framework to remove barriers to entry for flexibility sources.

4.2.4 Address electricity markets concentration and lack of liquidity where needed

The creation of organised markets must be accompanied with the removal of any barriers to entry to those markets which originate from the market structure or other issues, and where needed, implementing measures to promote competitive and liquid wholesale electricity markets. The existence of dominant vertically-integrated energy companies can reduce electricity market liquidity by circumventing the need to trade electricity via an organised platform. Market concentration in electricity generation can further worsen these barriers to entry of new participants, as large generators may sell most of their electricity through OTC long-term contracts and also dominate the organised markets. Market concentration may occur due to structural barriers, where incumbents have a dominant position (e.g. in the case of historical operators, which could have a lower opportunity cost to participate in the electricity markets due to sunk costs, and act strategically to avoid the entry of new actors), and/or legal and regulatory barriers, where measures such as price regulation restrict the entry of new players.[48]

Low market liquidity creates entry barriers for small and new market participants, by reducing the trading opportunities and increasing the transaction costs for participants.[49] Market concentration can occur not only in wholesale markets but also in the procurement of ancillary services, as large conventional power generators are often the main providers of balancing and other ancillary services, foreclosing a significant source of revenue for other flexibility sources. The creation of spot and

[47] CEER (2021) Long-Term Generation Investment Signals in a Market with High Shares of Renewables
[48] Energy Community Secretariat (2019) Policy Guidelines on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchanges
[49] ACER (2022) ACER Market Monitoring Report 2020 – Electricity Wholesale Market Volume. Section 7.2

balancing markets without resolving market structure issues (such as vertically-integrated companies bypassing the organised markets or market concentration leading to the potential abuse of market power by incumbent companies) increases the possibility for abuse of market power by incumbents, requiring ad-hoc measures such as price caps which go against the reasons the markets were created in the first place.

The Energy Community Secretariat provides policy guidelines on promoting competitive and liquid wholesale electricity markets. The guidelines aim to:

- Limit the influence of operators with significant market power and/or reinforce small players with a view to their participation in the markets;
- Eliminate cross-subsidies, margin squeezes or concerted actions within vertically integrated undertakings;
- Enhance liquidity on organized markets;
- Prevent market power abuse in electricity exchanges;
- Measures preventing market power abuse by the power exchange itself.

The guidelines include specific measures such as regulated access to existing generation capacity, termination of bulk supply agreements, and trading and market-making obligations. National governments and regulatory authorities should conduct an analysis of the current market structure and existing legal and regulatory barriers to entry of new market participants, and adopt the most adequate measures, including measures to address potential market concentration in the provision of ancillary and congestion management services. Further, there is also an important role of the Competition Authority to monitor, investigate and sanction abusive conduct of dominant undertakings.

The Secretariat guidelines do not cover measures to address potential market concentration in the provision of ancillary and congestion management services. Even if there are no concentration concerns in spot markets, this may still occur for ancillary and congestion management services as each service is highly specific and potentially only a handful of assets in each Contracting Party could be qualified to provide them. Therefore, measures to address concentration and promote liquidity in this market segment may also be necessary. The transition to a market-based procurement should be preceded by an assessment of the needs on the one hand and the potential service providers on the other hand, and the potential for market abuse. If this assessment indicates insufficient competition for one or several non-frequency ancillary services and for congestion management, regulatory authorities may choose for alternative approaches for non-discriminatory procurement, such as procurement at regulated prices open to all qualified providers, or cost-based mandatory provision. For balancing markets, price limits based on the marginal cost of the most expensive flexibility source may be adopted on a temporary basis to avoid market abuse in the early phases, but should be phased out as they are not compliant with the EU Electricity Target Model.

In order to develop liquid and transparent electricity markets, Contracting Parties should also foresee mechanisms to ensure their integrity and transparency, by transposing and implementing the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT). This is essential to ensure the trust of parties in the functioning of the system, in order to attract investments and new participants. It is important to note that balancing, redispatch and local flexibility markets (which in addition to other electricity and gas market segments can represent important revenue streams for flexibility sources) are within the scope of REMIT.[50] Currently, REMIT is applicable in the Energy Community without the requirement for centralised data reporting. Adoption and implementation of data reporting provisions is expected to be aligned with further integration into the EU day-ahead and intraday coupling regime.

The market-based procurement of electricity network losses could further contribute to enhancing market liquidity. Several different approaches are possible for procuring power losses, such as requiring TSOs and/or DSOs, suppliers, balancing responsible parties or other market participants to procure or pay for the costs of losses.[51] Promoting the use of non-discriminatory, market-based procedures could incentivise market liquidity, and thus indirectly flexibility sources.

4.2.5 Integrate markets

There are multiple arguments in favour of integrating markets regionally. The integration of Contracting Parties' electricity markets within the Energy Community and with EU Member States will improve the utilisation efficiency of flexibility sources across the region.

The development and integration of gas markets of Contracting Parties in order to improve access to gas from multiple sources and hence increase security of supply and reduce gas costs is important given the possible future role of CCGTs and to a lesser extent OCGTs in providing flexibility in the Energy Community, enabling, along other flexibility sources, both the phase-out of coal based power generation (and district heating) as well as the integration of renewable energy sources.[52] However, further detailed recommendations related to gas markets will not be formulated as the gas sector is not within the scope of the present study.

Also, as shown in the Tasks 2 & 3 report, electricity transmission interconnections form as such a major source of flexibility for all Contracting Parties. By interconnecting regions with different load profiles on the one hand and different RES penetration levels and mix of electricity generation sources on the other hand, the flexibility needs are reduced and can be covered at lower costs. The competent Authorities should also ensure that the TSOs maximise the interconnector capacity made available to the market, in order to increase their efficient use.

Moreover, electricity markets integration has been recognised as one of the main approaches to increase competition in Contracting Parties' electricity markets, given the high market concentration in national markets at the moment. Even where competition between national market participants is not yet possible (in the absence of measures addressing structural barriers), cross-border competition between national incumbents is possible, and can gradually increase market liquidity to a point where small and new market players may enter the market.

An important condition for regional market integration is the development of organised national markets, as described in the sub-section above. Contracting Parties should reform their national markets in view of enhancing competition at national level and with the aim of integrating them with the neighbouring markets.

[50] ACER (2021) Guidance on the application of Regulation(EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency
[51] CEER (2020) 2nd CEER Report on Power Losses
[52] Kantor and E3-Modelling (2021) A carbon pricing design for the Energy Community - Final Report

Integrating electricity markets at regional level requires actions in a number of domains. The initiatives should focus on coupling of day-ahead, intra-day and balancing markets, with coordinated interconnection capacity calculation and allocation. A particular important step in this regard is the expected adoption by the Contracting Parties of the market and system operation guidelines and network codes in the 2022 Council of Ministers.[53]

The Energy Community Secretariat has developed a proposal to couple markets in the Energy Community and bilaterally between specific Contracting Parties and Member States, in order to arrive finally at an European market coupling.[54] This would involve initially joint auctions of interconnection capacity by the concerned TSOs. Then, market coupling in the Energy Community would be implemented, with closing of market before EU SDAC closing[55]. Simultaneously, bilateral/regional agreements between Contracting Parties and EU Member States for regional capacity calculation in CCRs and CP-MSs market coupling can take place.

In order to maximise the benefits of market coupling, it will be necessary that TSOs adopt measures to substantially increase the interconnector's capacity availability for trade. While especially Western Balkans Contracting Parties have generally high interconnection capacity levels, their availability for market purposes is low.[56] The ECRB indicates that the capacity shares made available by TSOs for trade are (too) low due to overestimation of internal congestion, pessimistic power generation forecasts, and the fact that the transmission reliability margin is not (yet) calculated according to ENTSO-E rules and ECRB recommendations. Implementation of improved methodologies and ICT systems for the identification of critical network elements and calculation of NTCs is recommended, with the objective to move to (preferentially flow-based) coordinated capacity calculation between Contracting Parties, and also between CPs and EU MSs through specific arrangements, until the pan-European capacity calculation and allocation is implemented. The future adoption of the recast Electricity Regulation (EU) 2019/943 and it's 70% interconnector availability target in the Energy Community acquis should provide the high-level framework for these actions. The report on electricity interconnection targets from the Energy Community Secretariat defines the target in more detail[57].

4.2.6 Enable demand side flexibility

The Tasks 2 & 3 report indicates that flexibility sources such as smart-charging EVs and vehicle-to-grid can make relevant contributions to flexibility in the daily timeframe. Other demand side flexibility sources not modelled in this study, such as heat pumps, could further contribute to flexibility needs. In

[53] 27 th Energy Community Electricity Forum Conclusions. https://www.energy-community.org/dam/jcr:02dce2c2-4b89-4079-a299-db0f10607088/AF_conclusions_0622.pdf
[54] Energy Community Secretariat (2020) Bringing CACM and FCA Guidelines in the Energy Community
[55] Different gate closure times for the Energy Community and EU SDAC markets would be necessary until a pan-European coupling is in place, so that market clearing results from the Energy Community coupled markets can be considered in the bilateral coupling of certain Contracting Parties with Member States
[56] Energy Community Regulatory Board (2021) Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020
[57] Article 16(8) of Regulation (EU) 2019/943 shall be considered to be complied with where the following minimum levels of available capacity for cross-zonal trade are reached:

- for borders using a coordinated net transmission capacity approach, the minimum capacity shall be 70 % of the transmission capacity respecting operational security limits after deduction of contingencies;
- for borders using a flow-based approach, the minimum capacity shall be a margin set in the capacity calculation process as available for flows induced by cross-zonal exchange. The margin shall be 70 % of the capacity respecting operational security limits of internal and cross-zonal critical network elements, taking into account contingencies".

Energy Community Secretariat (2021) Electricity interconnection targets in the Energy Community Contracting Parties this context, measures concerning the design of retail markets are also relevant to activate demand side flexibility in the Contracting Parties in the future.

Contracting Parties should first ensure that the regulatory framework adequately defines and allows self-consumption, as well as active market participation of consumers/prosumers, either directly or via aggregation. Next to this, they should also foster smart metering in the residential and commercial sectors, based on a positive cost-benefit assessment, in order to enable these sectors to effectively provide demand side flexibility. While (large) industrial consumers are in general already equipped with smart meters, there is, as shown in Task 1 report, limited information regarding the potential for demand response in the Contracting Parties, despite some initiatives. Thus, efforts could be conducted to further identify and activate this potential.

While the modelling results indicate a more limited contributions to flexibility from demand-side resources compared to large-scale solutions, with the notable exception of EVs, the actual contributions in the future could turn out to be more significant. DSOs (in coordination with TSOs) will play a central role in providing signals for (active) consumers to reduce the system's flexibility needs, enable the connection and access to the network for distributed flexibility solutions, and procure their local flexibility needs (e.g. for congestion management) in an objective and non-discriminatory way. The regulatory framework should clearly define these tasks of DSOs, in alignment with the EU Electricity Regulation and Directive.

Phasing out blanket retail price regulation for large and small electricity consumers should be pursued as a priority, both to provide adequate price signals for these consumers as well as to improve the financial stability of suppliers and thus decreasing the need for regulatory intervention in the electricity sector. Target measures to protect vulnerable consumers are likely to remain necessary in the Contracting Parties. In order to incentivize demand response, wholesale market based electricity retail price formulas and eventually dynamic (i.e. real-time) electricity priced retail contracts could be promoted (while adequately informing consumers of the risks associated with such tariffs). Novel retail tariff designs such as critical peak pricing could be considered also, depending on the main aims of using time-differentiated tariffs.[58] Implementing time-of-use network tariffs could complement retail energy price signals to consumers. However, such approaches will have to be properly considered in order not to contradict the signals provided by time-differentiated retail energy prices nor over-complicate tariffs design and thus confuse consumers, and will hence not be a priority for short-term implementation.

4.2.7 Support flexibility markets and platforms

Flexibility markets (where flexibility is exchanged) and platforms (connecting flexibility providers with existing market platforms) are gaining significant attention, especially for the provision of local flexibility (but not only - such platforms could also make contributions at the national, and even regional level). Policymakers and regulators of the contracting Parties could further investigate the potential contributions of such initiatives, create a positive regulatory environment (including with the consideration of regulatory sandboxes if useful) and supporting pilots by various stakeholders (TSOs, DSOs, market operators and third parties).

[58] IRENA (2019) Time-of-use tariffs - Innovation landscape brief

4.2.8 Improve electricity infrastructure planning and operation

TSOs should prioritise the implementation of planned infrastructure projects. Even with increased availability of interconnectors following the measures indicated in the market integration section above, TSOs will likely need to undertake investments in additional interconnection capacity as the Tasks 2 & 3 report identified significant cross-border congestion for a few interconnectors in the ambitious scenario in 2040, even under the assumption of increased availability resulting from market integration. Moreover, coordinated planning will become increasingly important to ensure the integration of energy systems and of flexibility sources across sectors, borders and the transmission and distribution levels.

A CESEC study[59] also identified potential cross-border constraints under different scenarios in the region, further indicating that planned interconnection projects[60] would be sufficient to address expected congestions up to 2040, under the assumptions of the study. The Balkan region would currently be the most prone to congestion, confirming the results of Task 3 of the present study. Several of the priority interconnectors for investment identified in the CESEC study concern a Contracting Party and an EU Member State.

TSOs should prioritise not only cross-border projects but also the most important internal transmission projects. Addressing some internal constraints could also improve interconnector availability (even if TSOs are overestimating these constraints currently[61]) and facilitate the integration of electricity from wind energy parks and solar PV, as well as of flexibility sources. Network investments to modernise grids and address domestic constraints affecting interconnector availability should be undertaken by TSOs whenever these are identified as impacting cross-border availability or integration of RES or flexibility sources at present or in the future. The CESEC study identified potential internal constraints under different scenarios in Montenegro, Kosovo* as well as in EU Member States in South-East Europe, particularly Austria.[62] Network development plans should include the reconstruction plans for lines under and equal to 220 kV, as highlighted in chapter 3.

Developing infrastructure (both cross-border and internal), increasing interconnector availability through coordinated TSO actions, and coupling of markets across the different timeframes exhibit important synergies.[63] Therefore, TSOs should take planned market reforms into consideration and coordinate with national authorities and (if applicable) market operators when developing the network development plans.

The Continental South East (CSE) group of ENTSO-E acknowledges that increasing both cross-border and domestic capacities in the Balkans, where the network is less developed compared to other parts of Continental Europe, is a precondition for market integration in the region. It also notes the important benefits of increased interconnection and market integration not only in the region but also with

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[59] Ecorys et al. (2022) Study on the Central and South Eastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables

[60] Those included in the draft ENTSO-E TYNDP 2020, projects submitted for Project of Energy Community Interest (PECI) and Projects of Mutual Interest (PMI) status, the CESEC electricity action plan and network development plans of the Contracting Parties

[61] Energy Community Regulatory Board (2021) Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

[62] Ecorys et al. (2022) Study on the Central and South Eastern Europe energy connectivity (CESEC) cooperation on electricity grid development and renewables

[63] Kogalniceanu (2020) Projects of Energy Community Interest and Mutual Interest (PECI/PMI) - Legal Background and Process Introduction

neighbouring Member States, particularly Italy. Such market integration would further benefit if interconnection capacities between the EU and Turkey were increased.[64]

Electricity infrastructure planning in the Energy Community region is expected to be improved with the eventual ascension of the Ukrainian and Moldovan TSOs as ENTSO-E members, following the (emergency) synchronization of Ukraine and Moldova's power systems (IPS) to the Continental Europe Synchronous Area and further necessary actions. Ukrenergo has already obtained observer status.[65] In addition to improving coordination of planning of electricity infrastructure, this is also expected to improve the non-discriminatory consideration of network infrastructure alternatives in the TYNDP (if the TYNDP regional groups were adapted accordingly), given recent (and expected future) improvements to the TYNDP methodology, such as concerning the consideration of storage projects and the representation of their benefits. This could directly benefit (especially large-scale) flexibility sources. Agreements are in place for the TSOs adopting the necessary measures to comply with technical operational requirements and joining ENTSO-E.[66] Certification of the TSOs will also be required.

The Energy Community Secretariat could furthermore publish an assessment of the Contracting Parties' network development plans, in order to evaluate issues such as coordination with other national plans (such as NECPs), transparency, inclusion of non-TSO projects, and improved project assessment – as is currently conducted by ACER for EU Member States.[67]

TSOs and DSOs in the Contracting Parties will also need to increasingly coordinate network planning and operation, as the penetration of distributed renewable energy and flexibility sources increases. At the moment, this is still limited, but particularly rooftop solar PV could see a significant increase in CPs, as some already have incentive mechanisms such as net billing or net metering in place. This will require first of all information exchange in network planning, for example with DSOs providing distributed generation and load forecasts in the relevant planning timeframe to the TSO. Coordination will also be necessary for the connection, pre-qualification and finally access of flexibility sources for the participation in the different markets. However, the importance of these actions will depend on the stage of deployment in each Contracting Party. DSOs will need to also transparent elaborate network development plans in consultation with stakeholders, in order to ensure that distributions networks are capable of integrating both RES projects and distributed flexibility sources. The distribution network development plans should also consider non-wire alternatives to network expansion.

TSOs should also conduct comprehensive resource adequacy assessments with consideration of the potential of all flexibility sources to contribute to system adequacy. European and if needed national resource adequacy assessments (in accordance with art. 23 of Electricity Regulation 2019/943) will be central to identifying resource scarcity and the potential contributions of the different flexibility sources. The importance of the European Resource Adequacy Assessment (ERAA) will increase with the planned improvements in the methodology such as regarding the analysis of the economic viability assessment of storage, improved representation of demand response, storage and power-to-gas, among

[64] ENTSO-E (2021) Regional Investment Plan - Continental South East
[65] https://www.entsoe.eu/news/2022/04/26/entso-e-welcomes-ukrenergo-as-observer-member/
[66] https://www.gse.com.ge/about-us/international-affairs/Cooperation-with-ENTSO-E
https://www.entsoe.eu/news/2017/07/07/entsoe-ce-agreement-conditions-future-grid-connections-with-ukraine-moldova/
[67] See ACER Opinion 05/2021 on the electricity national development plans

other expected features.[68] The ERAA and if needed national assessments could provide strong signals on the need for flexibility, as well as for the eventual introduction of capacity mechanisms. The participation of TSOs from Kosovo*, Ukraine, Moldova and Georgia suggested above would expand the scope of the ERAA to these Contracting Parties. The remaining Contracting Parties are explicitly modelled in the ERAA. Moreover, once the EU Electricity Regulation is adopted into the Energy Community acquis, TSOs of UA+MD and the Western Balkans 6 as well as the relevant EU and Energy Community authorities should work towards integrating the Contracting Parties' systems into the system operation regions and associated regional coordination centres.

4.3 Specific measures and support for renewable electricity generation

Renewable electricity producers can be incentivised to reduce their contribution to the electricity system flexibility needs, as well as to actively provide flexibility services (such as downward balancing or re-dispatching) when possible. Such incentivisation measures comprise adequate support scheme design, phasing out of net metering / billing, and phasing out of priority dispatch. These measures need to be well-assessed and weighed against potential negative impacts on the achievement of the renewable energy targets of the Contracting Parties.

Feed-in premiums (fixed or with symmetric/asymmetric sliding premiums) with strike prices defined through auctions should be the default design for supporting large-scale renewable electricity projects. Feed-in premiums determined via competitive auctions are a better alternative than feed-in tariffs fixed by authorities. However, project promotors would then likely establish long-term PPAs with market parties to complement revenues, impacting spot market liquidity when those are eventually established.

Also, priority dispatch for large-scale renewable electricity should be removed, where in place, in line with article 12(2) of the Electricity Regulation 2019/943, when this is incorporated in the Energy Community acquis. Renewable energy producers should increasingly be responsible for managing their own primary imbalances. It is important also that liquid intraday and balancing markets exist and allow the entry of renewable energy producer and that transparent non-discriminatory procedures for balancing markets as well as congestion management are in place.

Until liquid markets are developed, hybrid approaches could be employed, with a central party aggregating the production or at least imbalances of the renewable energy producers, thereby reducing the aggregate imbalances (due to imperfect correlation of the RES generation profiles and of forecast errors between different RES producers) and allowing this central party to contract the necessary balancing reserves and energy at lower cost. This service could be offered to renewable energy producers at a fee.

As an example, RES producers could have the option to sell their production to the TSO or another central buyer, at an representative hourly market price. The central buyer would then sell the (aggregated) output in wholesale markets and assume the costs for managing imbalances (potentially passing through part of those costs in the price paid to the RES producers). This approach would contribute to increasing market liquidity - with the central buyer acting somewhat as a market maker - and reduce the balancing costs for especially small RES producers (as large producers with other assets

[68] ENTSO-E (2021) ERAA implementation roadmap. https://www.entsoe.eu/outlooks/eraa/implementation-roadmap/

in their portfolio would be much better placed to manage their own imbalances). It would simultaneously expose the RES producers to market prices, as long as the hourly price paid by the central buyer is set appropriately. Alternatively, RES producers could sell the production in the market, with the TSO managing only the imbalances of the RES producers for a fee, and socialising any residual balancing costs not covered by the fees. This could exposure the RES producers more directly to the market – however, that could be more difficult in the case of an illiquid market.

Further measures should be undertaken to increase the exposure of renewables to market signals. Gradual phase out of net metering and net billing schemes for prosumers should be adopted in order to incentivise prosumers to sell excess energy in the market and install behind-the-meter storage.

4.4 Carbon pricing and energy taxation

The Carbon Pricing study[69] analysed in detail options for the introduction of a carbon pricing mechanisms in the Contracting Parties, favouring the gradual introduction of such mechanisms combined with the integration of electricity and gas markets, and the subsequent integration of the mechanisms with the EU ETS. The study also recommended that Contracting Parties bring taxation rates on energy carriers to similar levels as in neighbouring EU Member States. These measures are not further detailed here but should be pursued by the Contracting Parties.

While it does not affect non-fossil flexibility sources directly, carbon pricing should serve to internalise the negative external costs of fossil-based generation, improving the level playing field for other flexibility sources which will compete in spot and ancillary services markets. Otherwise, for example coal and lignite power plants could crowd-out the other sources from the provision of flexibility.

Moreover, Contracting Parties should also revise the regulatory framework in order to ensure that double taxation of storage does not take place. Moreover, it is important that subsidies to fossil-based producers (as well as to coal mines) and suppliers are removed – in coordination with the removal of price regulation in all segments of the electricity value chain (especially wholesale and retail markets).

[69] Kantor and E3-Modelling (2021) A carbon pricing design for the Energy Community - Final Report

5 Flexibility needs, barriers and recommendations for the Contracting Parties

The following sections provide detailed information, analysis and recommendations per contracting party. For each CP we provide: 1) a summary of the flexibility needs, contributions and investments; 2) a short description of the status and barriers mainly with regards to the market design, structure and performance in each Contracting Party; and 3) recommendations for enabling flexibility sources, taking into account the specific context in each CP together with the set of measures described in chapter 4. As mentioned in Chapter 4, the full implementation of the Energy Community acquis should by each CP be considered as a priority, as the implementation of these provisions will deliver a level playing field for flexibility sources across the Energy Community.

5.1 Albania

5.1.1 Summary of flexibility needs, contributions and investments in Albania

The following table provides a summary of existing flexibilities in Albania.

Table 5-1 Summary of existing flexibilities in Albania

Albania	Current	Residual	
	2020	2030	2040
Flexible power generation	1 807 MW of hydroelectric reservoir capacity		
Storage	1 807 MW and 570 GWh of hydroelectric reservoir storage		
Interconnections	941 MW for import / 900 MW for export (situation as of 2022)		

The following table summarises the flexibility needs, contributions and investments in Albania.

Table 5-2 Summary of flexibility needs, contributions and investments in Albania

Albania		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	9 219	9 439	9 404	10 492	11 996	12 026
	Demand	8 998	9 028	9 028	9 918	10 073	10 073
Flexibility needs	Annual	257	257	257	291	357	357
	Weekly	256	261	261	389	655	655
	Daily	902	901	901	1 033	1 184	1 184
Flexibility contributions (GWh)							
CCGT	Annual	4	19	13	26	0	1
	Weekly	3	14	8	17	23	18
	Daily	6	37	29	20	23	18
Hydro reservoir	Annual	248	160	189	96	- 194	- 181
	Weekly	333	307	325	476	642	454
	Daily	551	508	678	969	839	619
Li-ion battery	Annual	0	0	0	0	0	0

Albania		2030 Baseline	2030 Ambitious FM	2030 Ambitious MI	2040 Baseline	2040 Ambitious FM	2040 Ambitious MI
	Weekly	0	0	0	0	1	0
	Daily	0	0	0	0	23	0
Electric vehicles	Annual	0	0	0	0	0	0
	Weekly	0	0	0	1	12	8
	Daily	2	11	10	22	172	168
Net imports	Annual	5	78	55	169	550	537
	Weekly	- 81	- 61	- 72	- 106	- 24	176
	Daily	342	344	184	22	127	378
Investments							
Investments (MW)	Li-ion battery					61	
CAPEX **(M€)**	Li-ion battery					9	

5.1.2 Main barriers for deployment and utilisation of flexibility sources in Albania

Albania has transposed the third energy package requirements and has unbundled its electricity TSO. However, the lack of proper unbundling of its DSO is subject to an infringement case with respect to the Energy Community acquis. In Albania, there are still no operational day-ahead markets, and the intra-day market is not organised either; however a competitive balancing market is operational since the 1st of April, 2021. Balancing capacity is procured through regular auctions based on pay-as-bid while balancing energy is procured using the marginal price (with no price caps). The cross-border coupling of day-ahead and intra-day markets is in the process of establishment and expected to go live towards the end of 2022. In its current state, the electricity wholesale market suffers from a lack of competition as it is distorted by a non-compliant public service obligation[70]. Albania gets most of its power supply from domestic hydroelectric plants which can provide for great flexibility under normal and satisfactory hydrological conditions.

Households and other customers connected to networks below 20kV are supplied by the universal supplier at regulated prices and without the possibility of switching.[71] This undermines the eligibility right of end-users to switch supplier and the interest of new suppliers to enter the retail market which is still highly concentrated, despite the Electricity Law granting switching eligibility to all customers.

Albania is well interconnected with its neighbours, it had an interconnectivity level[72] of 64% in 2020. However, the availability of the interconnectors for trading is relatively low, as only 20-21% of the Total Available Capacity was made available to market participants in 2020[73] . Albania is closely cooperating with Kosovo* on balancing, and on the establishment of the future power exchange (ALPEX) which is responsible for market coupling and setting up day-ahead and intra-day markets in Kosovo* as well.

[70] A bulk contract between state-owned companies is eliminating the possibility for market participants to compete for 86% of electricity volumes.
[71] ECS (2021), Annual Implementation Report 2021
[72] Total net transfer capacity divided by total installed power generation capacity
[73] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

5.1.3 Recommendations for enabling flexibility sources in Albania

Table 5-3 Recommendations for enabling flexibility sources in Albania

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Before 2030				
Complement draft NECP with transparent estimation of flexibility needs by 2030 and contribution from flexibility sources, and associated policies and measures	Governance	AL	New flex. Sources (Hydro RoR and reservoir, PV, EV smart charging/V2G, interconnectors)	Low
Unbundle electricity DSO Operatori i Shpërndarjes së Energjisë Elektrike Sh.A. (OSHEE) in line with EnC acquis	Unbundling	AL	All	Low
Assess adequacy and apply measures from ECS policy guidelines on increasing liquidity for wholesale markets, cease public service obligation of electricity purchases between state companies	Market structure/ Demand side flexibility	AL	EV smart charging/V2G, other DSM	Medium
Define aspects related to retail markets and distributed energy resources in regulatory framework, such as aggregators	Demand side flexibility	AL	EV smart charging/V2G, other DSM	Low
Develop organised DA and intra-day markets	Market development	AL	All	Medium
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	AL + neighbours	Interconnectors	Medium
Complete AIMS market coupling project	Market integration	AL, IT, ME, SE	Interconnectors	Medium
Develop bilateral market coupling arrangements with EU Member States and couple spot and balancing energy markets	Market integration	WB6	Interconnectors	Medium to High
Fully implement REMIT	Market monitoring	AL	All	Medium
De-regulate retail market prices and implement time-varying electricity pricing	Demand side flexibility	AL	EV smart charging/V2G, other DSM	Medium
Conduct CBA and implement smart meter roll-out, if favourable	Demand side flexibility	AL	EV smart charging / V2G, other DSM	Medium
Adopt secondary legislation to enable implementation of Article 15(8)[74] of the EE Directive (EED) under the NEEAP201	Regulation	AL	EV smart charging/V2G, other DSM	Low
Explicitly define prosumers in regulatory framework (Energy Law) and allow participation of all potential providers of demand response flexibility in the provision of balancing and other ancillary services	Demand side flexibility	AL	EV Smart charging/V2G, other DSM	Low
To 2030 and beyond				
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High

[74] According to Article 15(8) Member States shall ensure that national energy regulatory authorities encourage demand side resources, such as demand response, to participate alongside supply in wholesale and retail markets.

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	AL	CCGT, External costs internalisation	High
Adopt policies to develop and expand Li-ion Battery storage capacities	Demand-side flexibility / Storage	AL	Reduces flexibility needs	Medium
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	AL	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.2 Bosnia and Herzegovina

5.2.1 Summary of flexibility needs, contributions and investments in BiH

The following table provides a summary of existing flexibilities in Bosnia and Herzegovina.

Table 5-4 Summary of existing flexibilities in Bosnia and Herzegovina

Bosnia and Herzegovina	Current	Residual	
	2020	2030	2040
Flexible power generation	1 456 MW of hydroelectric reservoir capacity		
	2 065 MW of lignite capacity	1 353 MW of lignite capacity	600 MW of lignite capacity
Storage	1 456 MW and 1 711 GWh of hydroelectric reservoir storage 440 MW and 11 GWh of PHS		
Interconnections	2 100 MW for import / 2 100 MW for export		

The following table summarises the flexibility needs, contributions and investments in Bosnia and Herzegovina.

Table 5-5 Summary of flexibility needs, contributions and investments in Bosnia and Herzegovina

Bosnia and Herzegovina		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	17 707	14 507	14 370	13 759	17 022	16 919
	Demand	15 030	15 069	15 069	16 257	16 466	16 465
Flexibility needs	Annual	246	270	270	300	585	585
	Weekly	552	608	608	713	1 366	1 366
	Daily	996	1 025	1 025	1 206	1 844	1 844
Flexibility contributions (GWh)							
Lignite	Annual	168	- 18	- 18	81	39	32
	Weekly	216	98	101	168	89	62
	Daily	433	178	161	292	114	90
OCGT	Annual	0	0	0	0	3	8
	Weekly	0	0	0	0	1	3
	Daily	0	0	0	0	3	7
Hydro reservoir	Annual	247	173	269	234	9	55
	Weekly	430	322	358	447	476	431
	Daily	1 289	861	1 209	1 056	757	709
PHS	Annual	14	5	3	2	- 17	- 23
	Weekly	107	140	136	172	203	176
	Daily	217	312	341	283	656	639
Electric vehicles	Annual	0	0	0	0	0	- 1
	Weekly	0	1	1	2	24	20
	Daily	4	20	19	36	298	292
Net imports	Annual	- 183	110	15	- 17	546	510
	Weekly	- 202	48	12	- 76	567	668
	Daily	- 947	- 346	- 705	- 461	10	100

Bosnia and Herzegovina		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Investments							
Investments (MW)	OCGT					64	174
CAPEX **(M€)**	OCGT					24	66

5.2.2 Main barriers for deployment and utilisation of flexibility sources in BiH

The third energy package is still to be transposed in this CP. During the process of reform of the electricity sector, the Independent System Operator in Bosnia and Herzegovina, Sarajevo (NOSBIH) and Elektroprijenos Bosne i Hercegovine JSC Banja Luka (the Company for Transmission of Electric Power in BiH) started to operate in July 2005 and in February 2006 respectively. Bosnia and Herzegovina has an unbundled TSO, but not yet in line with the third energy package. The Independent System Operator in Bosnia and Herzegovina is responsible for power system control and is also the operator of the balancing market. Elektroprijenos Bosne i Hercegovine (Transmission company) is responsible for operation and maintenance, expansion and construction of the high voltage network (400 kV, 220 kV and 110 kV). Legal unbundling of the DSO in Republika Srpska was completed, but not in Federation of BH. There is no power exchange in BiH, thus neither day-ahead nor intra-day markets are operational, and market coupling depends on their establishment. A balancing market is operational since 2016 and ancillary services auctions are also operational. All customers in BiH have the possibility to choose their suppliers on the market. Customers that do not chose their supplier on the market are supplied by public suppliers, while households and small customers are supplied within the universal service at regulated prices. In 2020 a total of 6,542.92 GWh was delivered to the customers supplied within the universal service (65.6% of total final electricity consumption), while 3,427.73 GWh (34.4%) was delivered to customers at unregulated prices.

End-user electricity prices for household consumers and for small enterprises connected to the 0.4 kV network are regulated, and there is a high retail market concentration. BiH is well interconnected with its neighbours, with an interconnectivity level of 51% in 2020, meaning interconnector’s total net transfer capacity is equivalent to half the total installed generation capacity. However, the availability of the interconnectors for trading is relatively low, as only 42-40% of the Total Available Capacity was made available to market participants in 2020[75]. Despite that, no congestions have been reported on the cross-border and internal transmission network.

[75] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

5.2.1 Recommendations for enabling flexibility sources in BiH

Table 5-6 Recommendations for enabling flexibility sources in Bosnia and Herzegovina

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implemen-tation costs
Before 2030				
Define aspects related to retail markets and distributed energy resources in regulatory framework, such as aggregators and demand response	Demand side flexibility	BiH	EV smart charging/V2G, other DSM	Low
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	BiH	New flex. sources (EV smart charging)	Low
Develop organised day-ahead and intra-day market	Market development	BiH	All	Medium
Phase out price regulation while protecting vulnerable consumers	Price regulation	BiH	EV smart charging/V2G, other DSM	Medium
Assess adequacy and apply measures from ECS policy guidelines on increasing liquidity for wholesale markets[76]	Market structure/ Demand side flexibility	BiH	EV smart charging/V2G, other DSM	Medium
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	BiH + neighbours	Interconnectors	Medium
Adopt relevant regulations/by-laws supporting new RS RES Law (expected in the next 6-12 months) and market-based RES support schemes and adopt FBIH RES Law	Regulation	BiH	System-friendly RES / reduces flex. needs	Low
To consider EV smart charging/vehicle to grid aspects under the UNDP TA study "E-mobility and Market study in Bosnia and Herzegovina"	Demand side flexibility	BiH	EV smart charging/V2G, other DSM	Low
Incentivise market exposure to all new supported large-scale RES	RES market exposure	BiH	System-friendly RES / reduces flex. needs	Low
Develop bilateral market coupling arrangements with EU Member States	Market integration	WB6, UA+MD	Interconnectors	Medium to High
Fully couple with EU spot and balancing energy markets	Market integration	EU27, WB6	Interconnectors	High
Conduct a CBA and implement a smart meter roll out, if favourable	Demand side flexibility	RS	EV smart charging/V2G, other DSM	Medium
Phase-out subsidies to lignite power producers	Subsidies phase-out	BiH	Lignite external costs internalisation	High
Finalise trans-Balkans interconnector project	Network development	BiH	Interconnectors	Medium
To 2030 and beyond				
Ensure new OCGT/CCGT investments do not increase gas supply import dependency, by assessing alternative gas supply and route scenarios	Governance	BiH	Increased system resilience	Low

[76] Energy Community Secretariat (2019) Policy Guidelines on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchange

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implemen-tation costs
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	BiH	EV smart charging/V2G, DSM	Medium
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	BiH	Lignite external costs internalisation	High
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.3 Georgia

5.3.1 Summary of flexibility needs, contributions and investments in Georgia

The following table provides a summary of existing flexibilities in Georgia.

Table 5-7 Summary of existing flexibilities in Georgia

Georgia	Current	Residual	
	2020	2030	2040
Flexible power generation	2 381 MW of hydroelectric reservoir capacity 13 MW of coal capacity 485 MW of CCGT		
	682 MW of OCGT		110 MW of OCGT
Storage	2 381 MW and 950 GWh of hydroelectric reservoir storage		
Interconnections	1 480 MW for import / 1 480 MW for export		

The following table summarises the flexibility needs, contributions and investments in Georgia.

Table 5-8 Summary of flexibility needs, contributions and investments in Georgia*

Georgia		2030		2040	
		Baseline	Ambitious FM	Baseline	Ambitious FM
Supply / demand / flex needs (GWh)					
Annual generation and demand	Generation	14 048	19 912	15 143	23 530
	Demand	13 802	19 435	15 099	24 565
Flexibility needs	Annual	1 065	1 369	1 139	1 734
	Weekly	243	809	320	864
	Daily	839	1 341	980	1 637
Flexibility contributions (GWh)					
Coal	Annual	6	0	0	0
	Weekly	0	0	0	0
	Daily	1	0	0	0
CCGT	Annual	590	469	426	537
	Weekly	21	113	29	64
	Daily	50	131	66	77
Hydro reservoir	Annual	347	623	690	859
	Weekly	215	569	281	529
	Daily	773	1 063	883	1 087
Electric vehicles	Annual	0	0	0	3
	Weekly	0	2	1	17
	Daily	1	9	10	83
Net imports	Annual	122	212	0	295
	Weekly	6	66	0	228
	Daily	13	82	0	359
Curtailment	Annual	1	65	22	39
	Weekly	1	60	10	26
	Daily	1	57	21	30

Investments					
Investments (MW)	CCGT	103	84	34	174
CAPEX **(M€)**	CCGT	60	48	20	100

* Note the Ambitious Market Integration scenario does not exist for Georgia as only one projection of interconnection capacity was employed.

5.3.2 Main barriers for deployment and utilisation of flexibility sources in Georgia

Georgia has progressed well in some areas regarding electricity sector reforms in the past years. The unbundling of its electricity DSO is completed, however proper unbundling of the TSO is still pending. There are no operational day-ahead, intra-day and balancing markets; their launch was expected by January 2022. DA market now expected to go live in September 2022, ID market in December 2022. Cross-border market mechanisms and regional integration with other contracting parties are currently not possible as the electricity system of Georgia is not yet connected to any other Energy Community CPs or EU Member States, but building interconnectors is a long-term objective. Georgia's electricity system is connected and synchronized with Azerbaijan and Russia's system. Depending on the season, electricity is either exported or imported from its neighbours, including Turkey.

The electricity wholesale market of Georgia is less concentrated than that of other CPs, with the top three companies controlling only 43% of the market. End-user electricity prices for household and small consumers are regulated, and there is a high retail market concentration, with low switching rates and only two retail providers.

Georgia is well interconnected with its neighbours (Russia, Armenia and Turkey), with an interconnectivity level of 48% in 2020, meaning interconnectors' total net transfer capacity is equivalent to half the total installed power generation capacity. The available NTC of the interconnectors is however relatively low, with net transfer capacities amounting to only 51% of the nominal transmission capacities. Since GSE (the TSO) heavily restricts permitted loading of the 500 kV lines to Russia and Azerbaijan, the exchange possibilities between Georgia and Russia/Azerbaijan are limited, thus potentially creating needs for the construction of additional cross-border lines. Modernisation of the existing 500 kV lines could also be considered in order to increase the transmission capacities of Georgia toward its neighbours. Capacity allocation is implemented only on the borders with Turkey, but in a manner which is not compliant with the EU rules.

5.3.3 Recommendations for enabling flexibility sources in Georgia

Table 5-9 Recommendations for enabling flexibility sources in Georgia

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	GE	New flex. sources (CCGT, OCGT, Hydro RoR and reservoir, interconnectors)	Low
Incentivise market exposure of all new supported large-scale RES	RES market exposure	GE	System-friendly RES / reduces flex. needs	Low
Unbundle TSOs GSE in line with EnC acquis	Unbundling	GE	All	Low
Launch organised day-ahead, intra-day and balancing services markets in Q2 2022 as planned	Market development	GE	All	Medium
Fully implement REMIT	Market monitoring	GE	All	Medium
Build new cross-border interconnector with neighbouring EU countries (Romania) or Azerbaijan, Armenia and Turkey if necessary, to diversify imports	Interconnector availability	GE + neighbours	Interconnectors	High
Rehabilitate exiting interconnections and increase their maximum permitted loading up to the nominal transmission capacities	Interconnector availability	GE + neighbours	Interconnectors	High
De-regulate retail market and implement time-varying electricity pricing	Market design / Demand side flexibility	GE	EV smart charging/V2G, other DSM	Medium
Define aspects related to retail markets and distributed energy resources in regulatory framework, such as aggregators and demand response	Demand side flexibility	GE	EV smart charging/V2G, other DSM	Low
To 2030 and beyond				
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	GE	OCGT, CCGT external costs internalisation	High
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	GE	EV smart charging/V2G , other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.4 Kosovo*

5.4.1 Summary of flexibility needs, contributions and investments in Kosovo*

The following table provides a summary of existing flexibilities in Kosovo*.

Table 5-10 Summary of existing flexibilities in Kosovo*

Kosovo*	Current	Residual	
	2020	2030	2040
Flexible power generation	1 288 MW of lignite capacity	678 MW of lignite capacity	
Storage	-		
Interconnections	1 166 MW for import / 1 025 MW for export		

The following table summarises the flexibility needs, contributions and investments in Kosovo*.

Table 5-11 Summary of flexibility needs, contributions and investments in Kosovo*

Kosovo*		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	3 751	4 310	4 310	1 275	6 506	6 013
	Demand	6 050	8 581	8 581	6 513	9 504	9 504
Flexibility needs	Annual	699	964	964	742	1 060	1 060
	Weekly	137	550	550	170	1 204	1 204
	Daily	438	827	827	485	1 388	1 388
Flexibility contributions (GWh)							
Lignite	Annual	561	389	332	11	34	9
	Weekly	127	96	76	- 4	5	- 3
	Daily	591	335	278	5	18	2
CCGT	Annual	0	0	0	0	9	0
	Weekly	0	0	0	0	3	0
	Daily	0	0	0	0	4	0
OCGT	Annual	0	0	0	0	9	0
	Weekly	0	0	0	0	3	0
	Daily	0	0	0	0	5	0
Li-ion battery	Annual	0	0	0	0	5	0
	Weekly	0	0	0	0	16	0
	Daily	0	0	0	0	385	0
Electric vehicles	Annual	0	0	0	0	1	1
	Weekly	0	0	0	0	9	7
	Daily	1	6	6	12	96	90
Net imports	Annual	138	575	632	731	977	1 006
	Weekly	10	454	474	173	1 132	1 149
	Daily	- 154	486	543	469	854	1 259
Curtailment	Annual	0	0	0	0	25	44
	Weekly	0	0	0	0	35	52
	Daily	0	0	0	0	26	38

Kosovo*		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Investments							
Investments (MW)	CCGT	0	0	0	0	10	0
	OCGT	0	0	0	0	47	0
	Li-ion battery	0	0	0	0	745	0
CAPEX (M€)	CCGT	0	0	0	0	6	0
	OCGT	0	0	0	0	18	0
	Li-ion battery	0	0	0	0	112	0

*5.4.2 Main barriers for deployment and utilisation of flexibility sources in Kosovo**

Kosovo* is currently revising its 2017 energy strategy. The transmission and distribution system operators have been unbundled in Kosovo*. There are no operational day-ahead, intra-day and balancing markets. ALPEX, the Albanian power exchange is responsible for setting up day-ahead and intra-day markets in Kosovo* as well as cross-border coupling the two markets once these are established.

End-user electricity prices for household and non-household customers connected to the DSO network are regulated, and there is only one retailer as the liberalisation of the retail market was postponed for the 4th consecutive year.

Kosovo* is well interconnected with its neighbours, with an interconnectivity level of 106% in 2020, meaning interconnector's total net transfer capacity is slightly higher than the total installed power generation capacity.[77] However, the availability of the interconnectors is relatively low, with net transfer capacities amounting to only 23-25% of the nominal transmission capacities, restricting the possibility of cross-border trade of flexibility sources. Due to an ongoing dispute with the Serbian TSO (EMS) about the NTC values at the Serbian-Kosovo* border there is, at the time being, no allocation of capacity between biding zones. Transmission capacity allocations have been organized on all other borders (Montenegro, Albania, North Macedonia).

[77] ECS (2021), Electricity Interconnection Targets in the Energy Community Contracting Parties

5.4.3 Recommendations for enabling flexibility sources in Kosovo*

Table 5-12 Recommendations for enabling flexibility sources in Kosovo*

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Before 2030				
Approve Energy Strategy 2022-2031 and finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures as planned[78]	Governance	XK	New flex. sources (CCGT, EV smart charging/V2G)	Low
Finish drafting and publish Renewable Law enforcing market-based RES support	Governance	XK	System-friendly RES / reduces flex. needs	Low
Define aspects related to retail markets and distributed energy resources in regulatory framework, such as aggregators	Demand-side flexibility	XK	EV smart charging/V2G, other DMS	Low
Incentivise market exposure to all new supported large-scale RES	RES market exposure	XK	System-friendly RES / reduces flex. needs	Low
Launch organised day-ahead market as planned in Q1 2023 after ALPEX operationalisation	Market development	XK, AL	All	Medium
Develop organised intra-day market	Market development	XK	All	Medium
Fully implement REMIT	Market monitoring	XK	All	Medium
Couple DA market with Albania two months after the Albanian DA market goes live	Market integration	XK, AL	Interconnectors	Medium
Set the NTC values on Kosovar*-Serbian border and start to allocate capacity	Market integration	XK, RS	Interconnectors	Low
Ensure compliance of interconnector use with 70% availability target (while coordinating capacity calculation)	Interconnector availability	XK + neighbours	Interconnectors	Medium
Develop bilateral market coupling arrangements with other CPs and EU Member States	Market integration	WB6/neighbouring EU countries	Interconnectors	Medium to High
Fully couple with EU spot and balancing energy markets	Market integration	EU27, WB6	Interconnectors	High
Open retail markets and phase out price regulation while protecting vulnerable consumers	Price regulation	XK	EV smart charging/V2G, other DSM	Medium
Conduct a CBA and implement a smart meter roll out, if favourable	Demand side flexibility	XK	EV smart charging/V2G, other DSM	Medium
Adopt require secondary legislation to enable implementation of Articles 15(4) and 15(8) of the EE Directive (EED)	Regulation	XK	EV smart charging/V2G	Low

[78] Revised Energy Strategy document is planned to be approved by the Government by the end of June 2022. First NECP draft expected to be approved by Q2 2023, while final draft expected to be approved in Q2 2024 (Decision of the Ministerial Council of the Secretariat of the Energy Community dated 30.11.2021).

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Phase-out subsidies to lignite power producers	Subsidies phase-out	XK	Lignite external costs internalisation	High
To 2030 and beyond				
Ensure new OCGT/CCGT investments do not increase gas supply import dependency, by assessing gas supply and route scenarios (following the recommendations from Gas Development Plan, North Macedonia-Kosovo* Gas Interconnection Pipeline: Feasibility Study and the new Strategy of Energy 2022-2031).	Governance	MK, XK	Increased system resilience	Low
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS (maintaining a small share of free allowances in 2040)[79]	Carbon pricing	XK	Lignite external costs internalisation	High
Adopt policies to develop and expand large scale Li-ion Battery storage capacities	Demand-side flexibility / Storage	XK	Reduces flexibility needs	Medium
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	XK	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

[79] These small share of free allowances reflects the persisting difficulty of Kosovo* to deploy domestic renewables and storage facilities. Source: Energy Community (2021), A carbon pricing design for the Energy Community - Final Report

5.5 Moldova

5.5.1 *Summary of flexibility needs, contributions and investments in Moldova*

The following table provides a summary of existing flexibilities in Moldova.

Table 5-13 Summary of existing flexibilities in Moldova

Moldova	Current	Residual	
	2020	2030	2040
Flexible power generation	800 MW of coal capacities		-
	1 321 MW of natural gas capacities		40 MW of natural gas capacities
Storage	-		
Interconnections	800 MW for import / 1 200 MW for export		

The following table summarises the flexibility needs, contributions and investments in Moldova.

Table 5-14 Summary of flexibility needs, contributions and investments in Moldova

Moldova		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	1 736	2 820	2 802	2 523	7 269	7 411
	Demand	4 810	6 915	6 915	5 420	8 422	8 422
Flexibility needs	Annual	222	362	362	258	515	515
	Weekly	141	269	269	199	478	478
	Daily	351	529	529	428	878	878
Flexibility contributions (GWh)							
Coal	Annual	0	0	0	2	7	7
	Weekly	0	0	0	2	5	4
	Daily	0	0	0	1	0	0
CCGT	Annual	0	13	2	37	868	890
	Weekly	0	10	2	16	212	189
	Daily	0	9	2	21	205	201
OCGT	Annual	0	0	0	11	20	21
	Weekly	0	0	0	12	15	16
	Daily	0	0	0	7	2	1
Electric vehicles	Annual	0	0	0	0	2	2
	Weekly	0	1	0	2	24	21
	Daily	3	20	19	24	258	247
Net imports	Annual	222	349	360	208	- 386	- 412
	Weekly	141	259	267	168	217	239
	Daily	348	500	508	375	406	419
Investments							
Investments (MW)	CCGT	0	0	0	0	848	922
CAPEX (M€)	CCGT	0	0	0	0	488	530

5.5.2 Main barriers for deployment and utilisation of flexibility sources in Moldova

Moldova has transposed the third energy package requirements and has completed the unbundling of DSOs. However, the lack of unbundling of the electricity TSO is subject to an infringement case[80]. There are no operational day-ahead, intra-day and balancing markets. There is an administered balancing mechanism in operation. Market coupling is considered a long term objective and depends on the establishment of the day-ahead and intra-day markets. A cross-border procurement by the TSO of balancing capacity and energy is seen as a medium term objective, with the need for implementation of imbalance netting and the assessment of potential for cross-border exchange of other balancing reserves/services. The entry into force of the wholesale electricity market rules, which was initially envisaged for 2nd October 2021, was postponed but entered into force in the meantime.

In its current state, the electricity wholesale market suffers from a lack of competition, and is mainly limited to imports from Ukraine and the Moldavskaya GRES (MGRES) plant, which together supplied 81% of electricity demand in 2019 and 2020. Moldova was fully dependent on power generation owned by Russia (as well as Russian gas supply for power generation) and located in break-away Transnitria region. Moldova and Ukraine Hydrenergo signed contract to supply 30% of the country's needs, already operational.[81]

End-user electricity prices for household and small consumers are regulated, and there is a high retail market concentration, with low switching rates. Despite the Electricity Law granting switching eligibility to all customers, the competitiveness of retail suppliers is hampered because they only have limited access to wholesale supply of electricity. As a result, there are very few retail suppliers for consumers to choose from.

Moldova has an interconnectivity level of 27% in 2020, meaning its interconnectors' total net transfer capacity is equivalent to a quarter of the total installed power generation capacity. However, the availability of the interconnectors is relatively low, with net transfer capacities amounting to only 31% (import direction) and 46% (export direction) of the nominal transmission capacities, with values down to zero during certain periods. Until recently, Moldova's electricity grid was synchronously interconnected with Ukraine's Integrated Power System (IPS) and, in turn, Russia's Unified Power System (UPS) but not with Romania (part of ENTSO-E's Continental Europe Synchronous Area, with stricter regulations). As of 16 March 2022 an emergency synchronisation of the continental European power system (CESA) with the power systems of Ukraine and Moldova (IPS) has commenced following an urgent request by Ukrenergo and Moldova upon the Russian invasion of Ukraine[82], which will increase transmission capacities and transform electricity markets in both countries. The implementation of cross-border capacity allocation on the Moldovian-Ukrainian border has been agreed by TSOs, agreements and allocation rules were expected in Q1 of 2022.

[80] The Energy Community Secretariat opened dispute settlement proceedings against Moldova for lack of unbundling in May 2021. Source: https://www.energy-community.org/implementation/Moldova/EL.html
[81] https://circabc.europa.eu/rest/download/b4d9e0d9-03b0-4f05-acbd-c6463c0670f5?ticket=
[82] See more under *Ukraine*

5.5.3 Recommendations for enabling flexibility sources in Moldova

Table 5-15 Recommendations for enabling flexibility sources in Moldova

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	MD	New flex. sources (CCGT, OCGT, interconnectors)	Low
Develop organised intra-day, day-ahead markets and balancing markets	Market development	MD	All	Medium
Unbundle the electricity TSO in line with the EnC acquis	Unbundling	MD	All	Low
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	MD + neighbours	Interconnectors	High
Commission infrastructures supporting the integration of Ukraine and Moldova power systems into European electricity market (new RO-MD interconnector)	Interconnector availability	MD+RO	Interconnectors	High
Develop bilateral market coupling arrangements with EU Member States and couple spot and balancing energy markets	Market integration	EU27, MD+UA	Interconnectors	Medium to High
Explicitly define prosumers in regulatory framework and allow participation of all potential providers of demand response flexibility in the provision of balancing and other ancillary services.	Demand side flexibility	MD	EV smart charging/V2G, other DSM	Low
Phase out price regulation while protecting vulnerable consumers	Price regulation	MD	EV smart charging/V2G, other DSM	Medium
Phase out tax distortions created by reduced VAT on natural gas and zero VAT on electricity and heat for residential consumers	Subsidies phase-out/ Demand side flexibility	MD	EV smart charging/V2G, other DSM	Medium
Assess adequacy and apply measures from ECS policy guidelines on increasing liquidity for wholesale markets[83]	Market structure/ Demand side flexibility	MD	EV smart charging/V2G, other DSM	Medium
Incentivise market exposure to all new supported large-scale RES under the Renewable Law being drafted	RES market exposure	MD	System-friendly RES / reduces flex. needs	Low
To 2030 and beyond				
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	MD	Coal external costs internalisation	High
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	MD	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

[83] Energy Community Secretariat (2019) Policy Guidelines on increasing Competition and Liquidity of Wholesale Electricity Markets, including Power Exchange

5.6 Montenegro

5.6.1 Summary of flexibility needs, contributions and investments in Montenegro

The following table provides a summary of existing flexibilities in Montenegro.

Table 5-16 Summary of existing flexibilities in Montenegro

Montenegro	Current	Residual	
	2020	2030	2040
Flexible power generation	684 MW of hydroelectric reservoir capacity		
	210 MW of lignite capacity	-	
Storage	684 MW and 460 GWh of hydroelectric reservoir storage		
Interconnections	2 100 MW for import / 2 041 MW for export		

The following table summarises the flexibility needs, contributions and investments in Montenegro.

Table 5-17 Summary of flexibility needs, contributions and investments in Montenegro

Montenegro		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	2 922	3 870	2 922	3 083	5 122	4 649
	Demand	4 063	4 054	4 063	4 417	4 463	4 463
Flexibility needs	Annual	143	140	143	150	190	190
	Weekly	195	174	195	191	362	362
	Daily	361	305	361	410	792	792
Flexibility contributions (GWh)							
Lignite	Annual	0	- 25	0	26	0	0
	Weekly	0	33	0	10	0	0
	Daily	0	74	0	32	0	0
Hydro reservoir	Annual	140	80	115	191	82	131
	Weekly	98	104	84	103	136	128
	Daily	504	574	466	391	328	296
Li-ion battery	Annual	0	0	0	0	2	0
	Weekly	0	0	0	0	21	0
	Daily	0	0	0	0	494	0
Electric vehicles	Annual	0	0	0	0	0	0
	Weekly	0	0	0	0	4	2
	Daily	5	1	4	7	59	64
Net imports	Annual	3	85	28	- 68	105	52
	Weekly	97	37	111	77	199	221
	Daily	- 148	- 344	- 109	- 20	- 90	417
Curtailment	Annual	0	0	0	0	1	7
	Weekly	0	0	0	0	2	11
	Daily	0	0	0	0	2	15
Investments							

Montenegro		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Investments (MW)	Li-ion battery	0	0	0	0	975	0
CAPEX (M€)	Li-ion battery	0	0	0	0	146	0

5.6.2 Main barriers for deployment and utilisation of flexibility sources in Montenegro

Montenegro is advanced with regards to the electricity market reforms. It has completed the unbundling of TSOs and DSOs according to the Energy Community acquis. There are no operational day-ahead and intra-day markets yet, however a power exchange is established and was expected to be operational in day-ahead timeframe in 2020, and balancing market is competitive and functional. Market coupling depends on day-ahead and intra-day market establishment; although Montenegro has the intention to couple its markets with Albania, Italy and Serbia (AIMS), this project ongoing for years with precondition analyses finalised and having the Albanian PX onboarded in 2021. A cross-border balancing mechanism between TSOs is in place with Serbia and Bosnia and Herzegovina on a bilateral basis.

Montenegro's electricity consumption is mainly covered by hydropower, wind power and one lignite-fired power plant. There is no gas supply. The wholesale market is formally deregulated, and the country has an open market without regulatory obstacles for competition and new entrants. In its current state however, the market concentration is very high and the incumbent covers the whole retail market which results in no competition at all. Increases of end-user electricity prices for households have been limited by the Energy Law; however 42% of non-household customers (consuming 95% of electricity supplied to non-households) were supplied at unregulated prices.

Montenegro is well connected with its neighbours, with an interconnectivity level of 210% in 2020, meaning that its interconnectors' total net transfer capacity is double that of the total installed electricity generation capacity. However, the availability of the interconnectors is relatively low, with net transfer capacities amounting to only 37-38% of the nominal transmission capacities. Nonetheless, the availability for trading of the capacity is relatively high, with 74-72% of the Total Available Capacity made available to market participants in 2020.[84]

[84] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

5.6.3 Recommendations for enabling flexibility sources in Montenegro

Table 5-18 Recommendations for enabling flexibility sources in Montenegro

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	ME	New flex. sources (Hydro RoR and reservoir, system-friendly RES, battery storage)	Low
Transpose Clean Energy Package in primary legislation and regulate aggregators	Demand side flexibility	ME	EV smart charging / V2G, other DSM	Low
Assess adequacy and apply measures from ECS policy guidelines on increasing liquidity for wholesale markets	Market structure/ Demand side flexibility	ME	EV smart charging/V2G, other DSM	Medium
Develop organised DA and intra-day markets	Market development	ME	All	Medium
Fully implement REMIT	Market monitoring	ME	All	Medium
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	ME + neighbours	Interconnectors	Medium
Complete AIMS market coupling project	Market integration	AL, IT, ME, SE	Interconnectors	Medium
Develop bilateral market coupling arrangements with (neighbouring) EU Member States	Market integration	WB6	Interconnectors	Medium
Fully couple with EU spot and balancing energy markets	Market integration	EU27, WB6	Interconnectors	High
Finalise trans-Balkans interconnector project	Network development	BiH, ME, RS, RO	Interconnectors	Medium
Phase-out subsidies to coal/lignite power producers	Subsidies phase-out	ME	Lignite external costs internalisation	High
To 2030 and beyond				
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High
Adopt policies to develop and expand Li-ion Battery storage capacities	Demand-side flexibility / Storage	ME	Reduces flexibility needs	Medium
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	ME	Lignite external costs internalisation	High
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	ME	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.7 North Macedonia

5.7.1 Summary of flexibility needs, contributions and investments in North Macedonia

The following table provides a summary of existing flexibilities in North Macedonia.

Table 5-19 Summary of existing flexibilities in North Macedonia

North Macedonia	Current	Residual	
	2020	2030	2040
Flexible power generation	539 MW of hydroelectric reservoir capacity 311 MW of CCGT		
	829 MW of lignite capacity		-
Storage	539 MW and 609 GWh of hydroelectric reservoir storage		
Interconnections	1 050 MW for import / 991 MW for export		

The following table summarises the flexibility needs, contributions and investments in North Macedonia.

Table 5-20 Summary of flexibility needs, contributions and investments in North Macedonia

North Macedonia		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	6 209	5 983	5 547	5 397	8 836	8 640
	Demand	8 597	9 901	9 901	9 243	11 279	11 279
Flexibility needs	Annual	239	297	297	262	389	389
	Weekly	400	495	495	439	815	815
	Daily	660	863	863	733	1 345	1 345
Flexibility contributions (GWh)							
Lignite	Annual	175	0	0	5	0	0
	Weekly	77	0	0	0	0	0
	Daily	281	0	0	6	0	0
CCGT	Annual	154	141	111	190	82	144
	Weekly	38	54	24	57	56	46
	Daily	112	278	161	141	123	100
Hydro reservoir	Annual	128	317	372	282	376	427
	Weekly	103	141	106	96	229	152
	Daily	505	614	629	295	427	367
PHS	Annual	0	0	0	0	17	10
	Weekly	0	0	0	0	59	37
	Daily	0	0	0	0	363	157
Li-ion battery	Annual	0	0	0	0	1	0
	Weekly	0	0	0	0	2	0
	Daily	0	0	0	0	54	0
Electric vehicles	Annual	0	0	0	0	1	0
	Weekly	0	0	0	1	12	9
	Daily	2	9	10	16	141	146

North Macedonia		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Net imports	Annual	- 217	- 161	- 185	- 215	- 91	- 204
	Weekly	182	299	364	285	447	547
	Daily	- 241	- 39	63	275	229	555
Curtailment	Annual	0	0	0	0	5	12
	Weekly	0	0	0	0	10	24
	Daily	0	0	0	0	8	20
Investments							
Investments (MW)	CCGT	0	0	0	0	0	0
	Li-ion battery	0	0	0	0	108	0
	OCGT	0	0	0	0	0	0
	PHS	0	0	0	0	214	98
CAPEX **(M€)**	CCGT	0	0	0	0	0	0
	Li-ion battery	0	0	0	0	16	0
	OCGT	0	0	0	0	0	0
	PHS	0	0	0	0	188	86

5.7.2 Main barriers for deployment and utilisation of flexibility sources in North Macedonia

With the adaptation of the Energy Law in 2018 in North Macedonia, the overall electricity market became liberalized, with TSO and DSOs unbundled. January 1st, 2019 started the full liberalization of the Electricity Market. Since July 1st, 2019, the electricity price applied by the largest electricity producer AD Elektrani of the Republic of North Macedonia, is no longer subject to determination by the Energy Regulatory Commission, thus enabling full opening of the Wholesale Electricity Market. One of the most significant events in the electricity market is the nomination of MEMO DOOEL Skopje, the electricity market operator, as operator of the organized electricity market, that is obliged to organize and to administer the day-ahead and the intra-day electricity markets. Since October 1st, 2019, MEMO DOOEL Skopje, is charged with the electricity market organization and management, based on the license issued by the Energy Regulatory Commission. Previously, this activity was performed by the TSO AD MEPSO Skopje. A market-based system for ancillary services was established: MEPSO procures both the balancing reserve and energy in a competitive procedure, although only with two registered balancing service providers. There are obstacles in purchasing balancing services from other countries because of the difficulties with the VAT Law. The country is in the process of solving this obstacle. The Macedonian TSO is in the process of implementing Imbalance Netting within the SMM (Serbia-Macedonia-Montenegro) Block.

End-user electricity prices for household and other small consumers are regulated, and there is a high retail market concentration. North Macedonia is well interconnected with its neighbours, with an interconnectivity level of 55% in 2020, meaning interconnectors' total net transfer capacity is equivalent to over half the total installed power generation capacity. However, the availability of the interconnectors is relatively low, with net transfer capacities amounting to only 20-22% of the nominal (thermal ratings of the lines) transmission capacities. Moreover, only 25-34% of the Total Available

Capacity was made available to market participants in 2020[85]. This may restrict the possibility of cross-border trade of flexibility sources if there is congestion.

[85] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

5.7.3 Recommendations for enabling flexibility sources in North Macedonia

Table 5-21 Recommendations for enabling flexibility sources in North Macedonia

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	MK	New flex. sources (PHS, V2G, interconnectors)	Low
Develop organised intra-day and day-ahead markets	Market development	MK	All	Medium
Fully implement REMIT	Market monitoring	MK	All	Medium
Phase out price regulation while protecting vulnerable consumers	Price regulation	MK	EV smart charging/V2G, other DSM	Medium
Conduct a CBA and implement a smart meter roll out, if favourable	Demand side flexibility	MK	EV smart charging/V2G, other DSM	Medium
Introduce real-time price signals as considered in draft NECP	Demand side flexibility	MK	EV smart charging/V2G, other DSM	Low
Adopt draft Law on Energy Efficiency	Demand side flexibility	MK	EV smart charging/V2G, other DSM	Low
Revise the current Rulebook on renewable energy sources such that households and industrial facilities can sell surplus electricity to the universal supplier	Demand side flexibility	MK	EV smart charging/V2G, other DSM	Low
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	MK + neighbours	Interconnectors	Medium
Develop market coupling with IBEX (Bulgarian day-ahead market) as mentioned in NECP	Market integration	MK, BG	Interconnectors	Medium
Develop bilateral market coupling arrangements with EU Member States	Market integration	WB6	Interconnectors	Medium to High
Fully couple with EU spot and balancing energy markets	Market integration	EU27, WB6	Interconnectors	High
Incentivise market exposure to all new supported large-scale RES	RES market exposure	MK	System-friendly RES / reduces flex. needs	Low
Phase-out subsidies to lignite power producers	Subsidies phase-out	MK	Lignite external costs internalisation	High
To 2030 and beyond				
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	MK	Lignite external costs internalisation	High

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled	Implementation costs
Adopt policies to develop and expand Li-ion Battery storage capacities	Demand-side flexibility / Storage	MK	Reduces flexibility needs	Medium
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	MK	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.8 Serbia

5.8.1 Summary of flexibility needs, contributions and investments in Serbia

The following table provides a summary of existing flexibilities in Serbia.

Table 5-22 Summary of existing flexibilities in Serbia

Serbia	Current	Residual	
	2020	2030	2040
Flexible power generation	472 MW of hydroelectric reservoir capacity		
	4 437 MW of lignite capacity	4 073 MW of lignite capacity	
	255 MW of CCGT capacity	120 MW of CCGT capacity	-
Storage	472 MW of power capacity and 500 GWh of storage capacity of hydroelectric reservoir 639 MW of power capacity and 194 GWh of storage capacity of PHS		
Interconnections	3 825 MW for import / 4 025 MW for export		

The following table summarises the flexibility needs, contributions and investments in Serbia.

Table 5-23 Summary of flexibility needs, contributions and investments in Serbia

Serbia		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	36 445	28 906	29 125	23 456	32 003	29 619
	Demand	38 652	38 753	38 753	41 397	41 933	41 932
Flexibility needs	Annual	1 911	2 164	2 164	2 085	2 818	2 818
	Weekly	909	1 028	1 028	1 047	1 568	1 568
	Daily	2 603	3 074	3 074	3 007	4 817	4 817
Flexibility contributions (GWh)							
Lignite	Annual	3 495	1 425	1 408	1 769	246	179
	Weekly	1 059	405	402	292	46	30
	Daily	1 919	990	1 060	615	85	82
CCGT	Annual	124	119	117	221	1 003	149
	Weekly	40	34	30	43	212	32
	Daily	106	130	131	85	403	62
OCGT	Annual	0	0	0	0	210	88
	Weekly	0	0	0	0	29	19
	Daily	0	0	0	0	145	62
Hydro reservoir	Annual	- 36	- 33	- 36	- 36	- 35	- 41
	Weekly	115	91	112	143	132	145
	Daily	367	369	402	359	297	292
PHS	Annual	44	47	71	60	110	116
	Weekly	210	222	190	258	172	153
	Daily	518	822	1 004	754	1 649	1 639
Electric vehicles	Annual	0	0	0	0	7	7
	Weekly	1	5	4	10	65	61
	Daily	11	50	50	89	807	809

Serbia		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Net imports	Annual	-1 716	606	603	71	1 272	2 316
	Weekly	- 517	271	290	302	907	1 120
	Daily	- 319	713	427	1 107	1 427	1 866
Curtailment	Annual	0	0	0	0	4	5
	Weekly	0	0	0	0	5	7
	Daily	0	0	0	0	4	5
Investments[86]							
Investments (MW)	CCGT	0	0	0	0	863	0
	OCGT	0	0	0	0	2451	1787
CAPEX **(M€)**	CCGT	0	0	0	0	496	0
	OCGT	0	0	0	0	939	684

5.8.2 Main barriers for deployment and utilisation of flexibility sources in Serbia

In Serbia, the distribution system operator was unbundled in 2021. According to the Energy Community Secretariat, the transmission system operator Elektromreza Srbije (EMS) is not yet unbundled in a way which is fully compliant with the Energy Community acquis,[87] although this is disputed by the Serbian government and energy regulator. The day-ahead market is operational. Volumes traded reached 10% of electricity supplied to end-users in 2020. There is no intraday market, though it is expected to be operational in the first quarter of 2023. The legal basis for market coupling is defined in the Serbian Energy Law and a decree on day-ahead and intraday market coupling was adopted. Serbia participates in several market coupling initiatives, but there is no market coupling with neighbouring countries yet.[88] Recently the operator of the Serbian and Slovenian power exchanges as well as the respective TSOs have agreed to create the first regional power exchange covering the two countries and with the aim to integrate Hungary and other countries in the region - the Adriatic Danube Power Exchange (ADEX).[89] A market based procurement by the TSO of balancing capacity and energy was established in 2013. However, the publicly-owned EPS remains the dominant balancing service provider[90] and the prices of balancing reserves are still regulated.[91] Balancing cross-border cooperation is restricted to bilateral exchanges between TSOs from Bosnia and Herzegovina, Montenegro, Hungary and Romania.[92] The TSO EMS is a non-operational member of the IGCC imbalance netting project, planning to connect to the platform in April 2022.[93]

End-user electricity prices for household consumers are regulated, and there is a high retail market concentration, with low switching rates.[94] Serbia is well interconnected with its neighbours, with an interconnectivity level of 50% in 2020, meaning interconnector's total net transfer capacity is

[86] Note in the upcoming Serbian NECP, the reversible hydro power plant (RHPP) "Bistrica" project should be proposed as a flexibility source, instead of gas-fired power plants
[87] Energy Community Secretariat (2021) Annual Implementation Report
[88] Energy Community Secretariat (2021) Annual Implementation Report
[89] https://www.bsp-southpool.com/news-item/announcement-of-establishing-the-regional-power-exchange-for-Central-and-South-Eastern-Europe-ADEX.html
[90] EKC and IMP (2019) Technical Assistance to Connectivity in the Western Balkans, Component 2: Regional Energy Market. Final Report: Assessment of national balancing markets of beneficiary countries (Task 1)
[91] Energy Community Secretariat (2021) Annual Implementation Report
[92] ACER and CEER (2021) Market Monitoring Report 2021 - Electricity wholesale volume
[93] https://www.entsoe.eu/network_codes/eb/imbalance-netting/*
[94] ACER and CEER (2021) Market Monitoring Report 2021 - Electricity wholesale volume

equivalent to half the total installed power generation capacity. However, the availability of the interconnectors is relatively low, with net transfer capacities amounting to only 41-44% of the nominal transmission capacities.[95] Also, only 37-42% of the Total Available Capacity was made available to market participants in 2020. [96]

[95] Energy Community Secretariat (2021) Electricity Interconnection Targets in the Energy Community Contracting Parties
[96] ECRB (2021), Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020

5.8.3 Recommendations for enabling flexibility sources in Serbia

Table 5-24 Recommendations for enabling flexibility sources in Serbia

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	RS	New flex. sources (OCGT, CCGT)	Low
Develop organised intra-day market	Market development	RS	All	Medium
Qualify new BSPs and increase liquidity of balancing market to remove current price regulation	Market development	RS	PHS, OCGT, CCGT, interconnectors	Medium
Fully implement REMIT	Market monitoring	RS	All	Medium
Incentivise market exposure to all new supported large-scale RES	RES market exposure	RS	System-friendly RES / reduces flex. needs	Low
Phase out blanket price regulation while protecting vulnerable consumers	Price regulation	RS	EV smart charging/V2G, other DSM	Medium
Increase spot market competition through regional market integration and potentially market-making obligations for EPS	Market development	RS	PHS, interconnectors	High
Finalise the EMS unbundling process in cooperation with the EnC Secretariat	Unbundling	RS	All	Low
Set the NTC values on Serbian-Kosovo* border and start to allocate capacity	Market integration	RS, XK	Interconnectors	Low
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	RS + neighbours	Interconnectors	Medium
Complete AIMS market coupling project	Market integration	AL, IT, ME, SE	Interconnectors	Medium
Develop bilateral market coupling arrangements with EU Member States	Market integration	WB6	Interconnectors	Medium
Fully couple with EU spot and balancing energy markets	Market integration	WB6, EU27	Interconnectors	High
Finalise trans-Balkans interconnector project	Network development	RS	Interconnectors	Medium
Conduct a CBA and implement a smart meter roll out, if favourable	Demand side flexibility	RS	EV smart charging/V2G, other DSM	Medium
Phase-out subsidies to lignite power producers	Subsidies phase-out	RS	Lignite external costs internalisation	High
To 2030 and beyond				
Ensure new OCGT/CCGT investments, if they take place, do not increase gas supply import dependency, by assessing alternative gas supply and route scenarios	Governance	RS	Increased system resilience	Low
Develop regional WB6 market coupling following WB6 MoU	Market integration	WB6, SEE MSs	Interconnectors / reduces flex. needs	High

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	RS	Lignite external costs internalisation	High
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions	Demand side flexibility	RS	EV smart charging/V2G, other DSM	Medium

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

5.9 Ukraine

***Disclaimer: Following Russia's invasion of Ukraine on 24 February 2022, unforeseen changes in** the energy system of Ukraine (reduced power demand[97], damaged assets[98] and consecutive supply disruptions) have occurred that might change the below assessment. Resulting from an emergency synchronisation on 16 March 2022, **Ukraine's e**lectricity system is now interconnected with the Continental European Synchronous Area.*

5.9.1 Summary of flexibility needs, contributions and investments in Ukraine

The following table provides a summary of existing flexibilities in Ukraine.

Table 5-25 Summary of existing flexibilities in Ukraine

Ukraine	Current	Residual	
	2020	2030	2040
Flexible power generation	4 637 MW of hydroelectric reservoir capacity 13 835 MW of nuclear capacity		
	2 000 MW of fuel oil capacity	-	
	19 125 MW of coal capacity	4 820 MW of coal capacity	1 979 MW of coal capacity
	6 104 MW of CHP (nuclear and fuel oil) capacity	3 400 MW of CHP capacity	1 900 MW of CHP capacity
Storage	4 637 MW and 890 GWh of hydroelectric reservoir storage 1 834 MW and 13.8 GWh of PHS capacity		
Interconnections	1 900 MW for import (in the CESA) / 2 035 MW for export (in the CESA)		

Note that Tasks 2-3 assumed that the nuclear generation capacity decommissioned to the 2030-2040 horizon would be replaced by new capacity. The figures indicated refer only to currently existing capacity that would remain in the 2030-2040 horizon.

The following table summarises the flexibility needs, contributions and investments in Ukraine.

Table 5-26 Summary of flexibility needs, contributions and investments in Ukraine

Ukraine		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
Supply / demand / flex needs (GWh)							
Annual generation and demand	Generation	165 495	165 702	165 532	185 684	186 760	184 965
	Demand	162 112	163 838	163 838	182 920	186 322	186 313
Flexibility needs	Annual	9 236	8 677	8 677	10 005	9 703	9 703
	Weekly	3 087	4 563	4 563	4 006	6 152	6 152
	Daily	7 870	9 034	9 034	10 084	12 506	12 506
Flexibility contributions (GWh)							
Coal	Annual	3518	3727	2926	875	634	509

[97] According to IEA, UA's electricity demand has fallen by ca. 40% since Russia's invasion, mainly reducing nuclear generation https://www.iea.org/articles/ukraine-real-time-electricity-data-explorer?utm_content=buffer2e310&utm_medium=social&utm_source=linkedin.com&utm_campaign=buffer
[98] According to Ukrainian energy holding DTEK, 1,600km of power lines have been destroyed as of mid-April https://dtek.com/en/media-center/news/energetiki-povernut-svitlo-vsim-spozhivacham-kiivskoi-oblasti-do-1-chervn/

Ukraine		2030			2040		
		Baseline	Ambitious FM	Ambitious MI	Baseline	Ambitious FM	Ambitious MI
	Weekly	621	876	631	126	57	13
	Daily	2125	2065	1947	290	82	15
CCGT	Annual	615	578	528	1006	7401	7333
	Weekly	74	131	119	178	1787	1657
	Daily	429	450	466	218	1827	1572
OCGT	Annual	82	268	58	389	342	323
	Weekly	52	105	34	36	14	-1[99]
	Daily	54	142	30	87	23	14
Nuclear	Annual	313	486	506	5833	1968	2691
	Weekly	267	490	408	1794	1626	1624
	Daily	376	696	715	4980	2160	2907
Hydro reservoir	Annual	1256	1053	1047	1233	1055	1064
	Weekly	472	673	376	705	1142	767
	Daily	2038	1985	1821	2393	1588	1334
PHS	Annual	71	46	94	17	131	185
	Weekly	309	452	317	382	411	360
	Daily	2148	2431	2283	1406	2082	2526
Electric vehicles	Annual	0	1	1	-2	25	39
	Weekly	3	14	9	28	361	293
	Daily	78	576	580	533	5302	5082
Net imports	Annual	3380	2519	3516	653	-1856	-2442
	Weekly	1288	1823	2669	757	749	1438
	Daily	623	688	1195	176	-563	-947
Investments							
Investments (MW)	CCGT	0	0	0	0	5359	5434
	PHS	0	0	0	1	63	297
CAPEX **(M€)**	CCGT	0	0	0	0	3082	3125
	PHS	0	0	0	1	17	78

5.9.2 Main barriers for deployment and utilisation of flexibility sources in Ukraine

Ukraine has organised spot and balancing markets in place, and its deployment of RES and distributed energy sources is more advanced than in most other CPs. It should have in 2030 and 2040 the highest flexibility needs. Nonetheless, significant barriers still exist.

The unbundling of the TSO Ukrenergo was certified in 2021, and DSOs are also unbundled in Ukraine.[100] The day-ahead, intra-day and balancing markets are operational, but with significant interventions such as price caps (also for the procurement by the TSO of balancing capacity and energy) and the existence of a guaranteed buyer for electricity from RES under a support scheme which affect price formation.

[99] Negative flexibility contributions can be observed in very specific cases, due to 1) operational constraints in the model, particularly in the case of hydropower, and 2) dispatch constraints in neighbouring countries, when the technology is used to meet flexibility needs in neighbouring countries, which may appear as negative flexibility contributions in the host Contracting Party.
[100] Energy Community Secretariat (2021) Annual Implementation Report

Since the start of operation, wholesale market design has suffered continuous changes. Moreover, end-user price regulation for household creates cross-subsidies and leads to various financial imbalances in the value chain.

Up until early 2022, the system was separated between the Ukrainian Power System and the Burshtyn Energy Island (BEI), the latter of which was already synchronised with the Continental Europe Synchronous Area (CESA). Ukraine and the TSO planned to fully synchronise with the CESA by 2023, however progress has been accelerated in need of an emergency response and as of 16 March 2022 a trial synchronisation of the continental European power system with the power systems of Ukraine and Moldova has commenced following an urgent request by Ukrenergo and Moldova upon the Russian invasion of Ukraine[101]. Although trading is not happening yet[102], TSOs of Continental Europe are working with the two countries and regulators that are operating their respective power systems to assist in emergency needs. Moreover, Continental Europe TSOs under ENTSO-E and Ukrenergo have agreed on the pre-conditions that need to be met for the gradual development of electricity trade with Ukraine.[103]

The retail market is relatively competitive, with the three largest suppliers having a market share of 30%, and the penetration rate for residential smart meters was 10% of total number of residential smart meters in 2020[104]. However, price regulation for households and cross-subsidies still significantly distort retail market. At 11%, the interconnectivity level is low compared to other Energy Community Contracting Parties, and is lower if only interconnections to ENTSO-E members are considered. Before Russia's invasion of Ukraine, market players in the BEI could access cross-border capacities to/from Hungary, Slovakia and Romania, with BEI being a net exporter. However, total export available transfer capacity was capped at 650 MW (depends on import nominations), leading to a reduction of the cross-border capacity (unilaterally) auctioned in a yearly, monthly and daily basis. Consequently, the availability of interconnectors was relatively low before the synchronisation, with net transfer capacities (for all of Ukraine) amounting to only 34-37% of the nominal transmission capacity, but with the full synchronisation with the ENTSO-E network it should increase[105].

[101] https://www.entsoe.eu/news/2022/03/16/continental-europe-successful-synchronisation-with-ukraine-and-moldova-power-systems/
[102] https://www.reuters.com/business/energy/europe-ukraines-plan-link-power-grids-2022-03-01/
[103] https://www.entsoe.eu/news/2022/06/08/continental-europe-tsos-confirm-the-technical-pre-conditions-for-the-gradual-opening-of-electricity-trade-with-ukraine/
[104] ECRB (2021), Market Monitoring Report: Gas and electricity retail markets in the Energy Community. Reporting period 2020.
[105] According to the Minister of Energy in UA, technological initiatives following the synchronisation could increase the transmission capacity of Ukrainian power grid connected with ENTSO-E countries up to 4 GW and even 5 GW. https://interfax.com.ua/news/economic/815778.html

5.9.3 Recommendations for enabling flexibility sources in Ukraine

Table 5-27 Recommendations for enabling flexibility sources in Ukraine

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
Before 2030				
Finalise NECP with transparent estimation of flexibility needs and contribution from flexibility sources, and associated policies and measures	Governance	UA	New flex. sources (CCGT, nuclear, interconnectors)	Low
Define aspects related to retail markets and distributed energy resources in regulatory framework, such as aggregators	Demand side flexibility	UA	EV smart charging/V2G, other DSM	Low
Develop liquidity of DA and intra-day markets	Market development	UA	All	Medium
Make qualification of new ancillary services providers easier, increase competition and remove price caps on ID, DA and balancing/ancillary markets	Market development	UA	Hydro reservoir, PHS, CCGT, nuclear, interconnectors/ reduces flex. needs	Medium
Incentivise market exposure to all new supported large-scale RES	RES market exposure	UA	System-friendly RES / reduces flex. needs	Low
Fully implement REMIT	Market monitoring	UA	All	Medium
Modernise electricity networks, attract investments into post-war sustainable and resilient infrastructure accommodating flexibility needs	Develop network capacities	UA	All	High
Fully couple with EU DA, ID and balancing energy markets after emergency synchronisation	Market integration	EU27, MD, UA	Interconnectors	Medium to High
Ensure compliance of interconnector use with 70% availability target	Interconnector availability	UA, neighbour MSs	Interconnectors	Medium
Increase cross-border flows via CESA / Make use of increased interconnection & transmission capacity after full synchronisation with CESA	Interconnector availability	EU27, MD, UA	Interconnectors / reduced flex. needs	Low
Phase out price regulation while protecting vulnerable consumers	Price regulation	UA	EV smart charging/V2G, other DSM	Medium
Conduct a CBA and implement a wider smart meter roll out, if favourable	Demand side flexibility	UA	EV smart charging/V2G, other DSM	Medium
Lift barriers for demand response (finalise Data Hub for accurate and timely data access; ensure adequate monitoring, verification and enforcement; improve institutional capacity and knowledge)	Market monitoring and case investigation	UA	EV smart charging / V2G, other DSM	Medium
Phase-out subsidies to coal/lignite mines and power producers	Subsidies phase-out	UA	Coal external costs internalisation	High
To 2030 and beyond				
Develop carbon pricing with complete phase-out of free allowances for power generation and integration with EU ETS, to be completed by 2040	Carbon pricing	UA	Coal external costs internalisation	High
Adopt policies to increase penetration of EV smart charging and vehicle-to-grid solutions (such as potentially requirements or incentives that new publicly accessible as	Demand side flexibility	UA	EV smart charging/V2G, other DSM	Medium

Recommendation	Category	Concerned CPs/MSs	Main impacts/ flex. sources enabled*	Implementation costs
well as private charging stations allow unidirectional, and if beneficial, bidirectional charging)				
Ensure new OCGT/CCGT investments do not increase gas supply import dependency, by assessing gas supply and route scenarios	Governance	UA	Increased system resilience	Low

** Only the main flexibility sources identified in the T2/T3 report are mentioned, plus other demand side flexibility. Measures could nonetheless facilitate other flexibility sources not mentioned.*

6 Annex: Barriers to flexibility deployment and utilisation per CP

6.1 Albania

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Albania's draft Draft NECP was submitted to the Energy Community Secretariat, and ECS' recommendations received. Based on the comments Albania needs to consider system flexibility aspect in a much more integrated way in its NECP. The ECS recommends '*setting specific objectives and timelines on smart grids, aggregation, demand response, storage, distributed generation, mechanisms for dispatching, re-dispatching and curtailment, real-time price signals including the roll-out of intraday market coupling and cross-border balancing markets and non-discriminatory participation; consumers participation in the energy system and benefit from self-generation and new technologies, including smart meters, electricity system adequacy, as well as flexibility of the energy system with regard to renewable energy production, and grid congestions*' , as well as recommends to involve more stakeholders in the consultation on long-term energy plans.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	Partially	Energy Law Article 3(88) defines: 'self-producer is a person who produces electricity and consumes mainly for its own needs most of the energy produced.' There is no clear prosumer definition but essentially, the definition self-producers in the Energy Law also covers the concept of prosumers. Renewable law is being reviewed and is expected to cover this area.
	Aggregators not defined in regulatory framework	Yes	A framework to enable demand response and aggregators is missing.
	Absence / issues with Day-ahead market	Yes	The day-ahead market is not yet operational.
	Absence / issues with Intra-day market	Yes	The intra-day market is not yet operational, although gate closure for intraday nominations is H-2 before the delivery.
	Absence / issues with Balancing market	No	Balancing market is operational.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Market coupling depends on the establishment of organised DA and ID markets.
	Price caps and other restrictions on wholesale markets not indicated above	-	No DA, ID market established, lack of competition on wholesale markets
	End-user price regulation / other interventions	Partially	End-user electricity prices for household consumers were regulated in 2020. In Albania, there is no price regulation for non-households connected to the 35kV network and since 2022 also not for those connected to the 20kV. 78 metering points supplied at non-regulated prices 2020. This is expected to increase in 2022.
	Lack of time-differentiated retail commodity prices	Partially	The regulator applies different tariffs at peak times; however, there is no proper implementation of time-varying electricity pricing; as the retail market remains highly regulated.
	Lack of / non-compliant TSO or DSO unbundling	Partially	The lack of unbundling of electricity DSO is subject to an infringement case in the Energy Community, but in the last 2 years significant process has been achieved. Unbundling of the transmission system operator is completed.

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Market structure and performance	Electricity wholesale market concentration	Yes	Generation CR1 of 58%. In its current state, the electricity wholesale market suffers from a lack of competition.
	Limited/no competition in electricity retail markets	Yes	High market concentration, CR3 >90% for whole market and at or near 100% for residential sector 7-25 retailers exist. High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. The Electricity Law grants switching eligibility to all customers, however, while there was some initial interest, with the price surge everyone preferred to stay under USS.
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Albania is well interconnected with neighbours, with an interconnectivity level of 64% in 2020, meaning interconnector's total net transfer capacity is equivalent to half the total installed generation capacity. In reference and RES scenarios, Albania-Greece interconnection could face structural congestion in 2030 and 2050.[106] However, there is one line 400 kV between two countries, at the moment underutilized.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The availability of the interconnectors is relatively low, with net transfer capacities amounting to only 29-30% of the nominal transmission capacities. Also, only 20-21% of the Total Available Capacity was made available to market participants in 2020 (ECRB, 2021, Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020).
	Other network capacity, capacity allocation and congestion management issues	-	NA
	Inadequate network tariff design	Yes	Time-of-use tariffs not in place
	Lack of smart metering for low voltage-connected users	Partially	In the framework of Law 43/2015 "Over Energy Sector" requirements in article 78 " Intelligent metering systems", OSSH sh.a has already implemented two small Pilot Projects (installing of smart meters in more than 3 500 low voltage costumers that are supplied by four feeders placed in Tirana & Durres). With regard to meter installation for self-consumers (prosumers) there are defined rules which include: Law 7/2017 "Over fostering of RES", Guideline No 3 approved in 2019 by MIE, Methodology of self -consumers connection into the DSO grid prepared by DSO (OSSH sh.a) not yet approved by ERE.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	Yes	According to the ECS comments on the draft NECP[107], *"Grid stability planning should take into account both renewable energy and electricity in transport in an integrated manner. The policies and measures on the electrification of transport are not linked to the policy and measure on demand side management and electricity storage systems for grid flexibility."*
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	-	NA
	Subsidisation of fossil-based / other power generation	No	No fossil fuel generation at the moment

[106] Ecorys et al. (2021), Study on CESEC cooperation on electricity grid development and renewables
[107] https://www.energy-community.org/regionalinitiatives/NECP.html

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Market distortions due to support schemes	Partially	Administratively-set FiT in place (legacy of previous project), foreseen to be converted to CfDs once DA market is operational. Auctions with a fixed purchase price were conducted, envisaging conversion into CfD once a day-ahead market is operational.[108]
Technology-specific barriers	Other barriers to demand response	Yes	Regulatory framework does not provide for the participation of demand response in the provision of balancing and other ancillary services. Article 15(8) of the EE Directive has not been transposed and the issue is not tackled under the EED progress report. Measures outlined under the NEEAP201 in relation to art. 15(8) appear insufficient. The regulator applies different tariffs at peak times; however, there is no proper implementation of time-varying electricity pricing; as the retail market remains highly regulated. There are certain plans for investments in smart grids and deployment of smart metering; as well as plans for developing net metering for solar generators.
	Other barriers to Gas-fired generation	No	Gas network not developed in Albania. However, the new TAP pipeline has been recently put in operation, passing through Albania. Locations close to this pipeline may be used for new gas fired power plants. TPP Vlore is planned to be switched to gas, it is not very distanced from TAP but there is an option also for LNG.
	Other barriers to EV smart charging / vehicle-to-grid	Partially	No e-mobility issues defined in legislation. The policies and measures on the electrification of transport in Albania's draft NECP are not linked to the policies and measures on demand side management and electricity storage systems for grid flexibility. In the master plan "Investment and Network Development Plan for the Electricity Distribution Sector in Albania " , period 2018-2034, conducted by VPC GmbH, "Electric mobility and Digitalization" are among the influencing factors that must be qualitatively assessed for the future.
	Other barriers to Storage (front / behind-the-meter)	-	NA
	Barriers to other technologies / existing power plants	Yes	It is worth to note, in particular for the flexibility aspects, that there is significant small must-run hydro capacity which during the wet periods produces up to circa 40% of consumption. Since Albania relies on HPPs, unfavourable hydrological conditions may limit their production, including a provision of the flexibility services. This may occur on an annual level, but also seasonally, especially during summer months.

108 ECS (2021), Annual Implementation Report 2021

6.2 Bosnia and Herzegovina

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Yes	Third Energy Package still to be transposed, and a state-level law that would allow the creation of DA markets and then market coupling is still to be adopted. An early version of the NECP was submitted to the Secretariat in November 2020. Legal basis needed for NECP has not yet been established (BiH Implementation Report 2021 EnC). At the end of November 2020, the Clean Energy Package II was adopted within the Energy Community Treaty, ie Energy Efficiency Directive 2012/27 / EU amended by (EU) 2018/2002, Renewables Directive (EU) 2018/2001 and Governance Regulation (EU) 2018/1999. Having in mind the above, activities on the development of the NECP have been intensified, which will fully take into account these obligations as well as other strategic documents. Once implemented (expected by the end of 2022), NECP will enable BiH to integrate energy and climate goals, as well as policies and measures, helping to align energy policies with the EU, and as such will serve as a long term strategic document that will define future development of the energy sector. On the other hand, NOS BiH (ISO) prepares the Indicative generation development plans regularly and the transmission company (Elektroprijenos BiH) prepares TYNDPs based on the generation plans. Both are based on the expressed interest by investors in the new generation facilities and certain maturity of projects development/ permitting process.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	Partially	New RS RES Law is adopted on 22nd February 2022, No 01-020-635/22. This law is basis for prosumer (buyer-producer), renewable energy communities, RES auctions, etc. Relevant regulations/by-laws will be adopted in a period from 6 months to one year. Pre-draft of FBIH RES Law is prepared. It is expected to be placed in adoption procedure very soon. Article 3 of RS RES Law provided definition of prosumer as "buyer-producer" of electricity from renewable energy sources meaning: end customer, who operates within its premises located within limited areas and who produces electricity from renewable energy sources for its own consumption, or who can store or sell electricity produced from renewable energy sources is self-produced, and for customers who do not belong to the household category, these activities do not represent their main commercial or professional activity. Calculation of taken and deliver electricity to the grid is done by net-metering (for facilities up to 10.8kW), net-billing schemes (for facilities from 10,8 - 50 kW), standard billing scheme (for facilities over 50kW).
	Aggregators not defined in regulatory framework	Yes	No definition of aggregators in the national regulatory framework or other provision related to aggregators has been identified.
	Absence / issues with Day-ahead market	Yes	No operational day-ahead market. Adoption of a new legal act to establish day-ahead markets was postponed.
	Absence / issues with Intra-day market	Partially	No operational intra-day market. Network users can submit to TSOs intraday schedules, and conduct bilateral trades after D-1.[109]
	Absence / issues with Balancing market	Partially	The balancing market is operational (established on 1 January 2016), with caps defined by the regulator. However, there are limited providers so there is lack of certain load and frequency reserves resulting in significant cross-border deviations occasionally.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Market coupling depends on the establishment of organised day-ahead and intra-day markets. Network users could in 2019 access cross-zonal capacities in intra-day timeframe on all borders. There are no legal obstacles for purchasing services from other countries.

[109] ECS (2019), State of electricity intraday markets in the Energy Community

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Price caps and other restrictions on wholesale markets not indicated above	-	No DA, ID market established.
	End-user price regulation / other interventions	Yes	End-user electricity prices for household consumers were regulated in 2020. Small enterprises connected to the 0.4 kV network were entitled to supply under regulated end-user electricity prices; for all other customers (about 10% of non-household customers who consumed 67% of the electricity consumed by all non-household customers) prices were not regulated.
	Lack of time-differentiated retail commodity prices	-	NA
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	Partially	BiH has unbundled TSO (ISO + transmission company), but not in line with the Third energy package. Legal unbundling of the DSO in Republika Srpska was completed, but not in Federation of BH.
	Electricity wholesale market concentration	Yes	Generation CR2 of 41+32+13%.
	Limited/no competition in electricity retail markets	Yes	High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. 7-25, competition is still to develop.
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Well interconnected with neighbours, with an interconnectivity level of 51% in 2020. The large interconnection capacity may act as a deterrent to developing domestic sources of flexibility. In reference and RES scenarios[110], HR-BiH interconnection could face structural congestion in 2030 and 2050 though this may be linked to (unrealistically) high RES development. There are 2 lines 400 kV and 6 lines 220 kV between the two countries and, under certain conditions, there might be some congestions but this should be manageable with re-dispatching.
	Existing interconnector capacity is not (sufficiently) made available to the market	Partially	The availability of the cross-zonal capacity given to the market players is relatively low, with net transfer capacities amounting to only 28% of the nominal transmission capacities, in average which may restrict the possibility of cross-border integration of flexibility sources. Also, only 42-40% of the Total Available Capacity was made available to market participants in 2020 (ECRB, 2021, Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020). However, existing capacities are not congested, which is confirmed by the low auction prices. BiH has a relatively high electricity surplus (circa 5 TWh) which is exported without any problems.
	Other network capacity, capacity allocation and congestion management issues	No	Coordinated Auction Office in South East Europe (SEE CAO) performs explicit allocation of cross-border transmission capacities between Bosnia and Herzegovina and Croatia and Bosnia and Herzegovina and Montenegro. NOSBiH participate in work of SEE CAO. Explicit allocation capacities on Bosnia and Herzegovina-Serbia border is performed on the basis Allocation Rules approved by SERC. There were not congestions registered on the cross-border nor internal transmission lines in the previous period.
	Inadequate network tariff design	No	Time-of-use tariffs are applied / possible, though they depend on the daily high and low load conditions, not on imbalances in the system. No other barriers identified in this aspect.
	Lack of smart metering for low voltage-connected users	Partially	The residential smart meter penetration was 21% in 2020.[111] Smart metering is a pre-condition for the development of behind-the-meter flexibility sources. Prosumers are required to have bi-directional meters installed in their premises.

[110] Ecorys et al. (2021), Study on CESEC cooperation on electricity grid development and renewables
[111] ECRB (2021). Market Monitoring Report Gas and Electricity Retail Markets in the Energy Community. Reporting period 2020.

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	-	NA
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	Yes	Federation of BiH yet to allow self-consumption; Republika Srpska enabled net metering for small installations. Natural persons are still taxed for self-generated electricity that is fed into the grid. New RS RES Law was adopted in February 2022 and pre-draft of FBIH RES Law is prepared and expected to be adopted soon. The new RS RES law is the basis for prosumer (buyer-producer), renewable energy communities, RES auctions, other. Relevant regulations/by-laws will be adopted in a period from 6 months to one year.
	Subsidisation of fossil-based / other power generation	Yes	42.91M EUR of direct subsidies provided to coal/lignite electricity producers in 2018/2019, or an equivalent average of 2.1 EUR/MWh. This affects the competitiveness of flexibility sources.
	Market distortions due to support schemes	Partially	Two self-consumption schemes for small-scale renewable energy technologies, namely net metering and net billing. FiPs exist. Adoption pending for regulatory framework establishing market-based support schemes.
Technology-specific barriers	Other barriers to demand response	Yes	There is no framework to enable demand response. Demand side response was, in some cases, activated through ancillary services.
	Other barriers to Gas-fired generation	Partially	Bosnia and Herzegovina purchases natural gas imported from Russia through the only interconnector with Serbia and its gas market is underdeveloped.
	Other barriers to EV smart charging / vehicle-to-grid	Partially	New RS RES Law defines (article 49 and 50) that Government can introduce certain measures for development of market for RES in transport sector, including development of infrastructure for use of electricity and alternative fuels. In this case, Government will adopt Regulation on use or RES and alternative fuels in transport sector. Content of this regulation would be: types of fuels, measures for support infrastructure development and monitoring of application of this Regulation. When it comes to development and improvement of e-mobility in BiH, MoFTER requested technical assistance from UNDP, through which a study "E-mobility and Market study in Bosnia and Herzegovina" is being developed. Planned content of the Study: 1. Review and analysis of the existing market and institutional framework 2. Business models for the rapid introduction of e-mobility infrastructure 3. List of tasks and impact of the measures identified under tasks 1 and 2. 4. Possibility of electrification and investment in the BiH fleet 5. The overall impact of demand and energy supply constraints on e-mobility 6. Stakeholder consultation and awareness raising 7. Recommendations on necessary policy measures at the state level Following these activities and what is being done through NECP process, MoFTER has established a Working group for e-mobility in Bosnia and Herzegovina, whose main goal is to identify major obstacles to the development of e-mobility in Bosnia and Herzegovina and draft solutions for the development and effective improvement of e-mobility. The Secretariat of the Energy Community also participates in the work of this group.
	Other barriers to Storage (front / behind-the-meter)	-	NA

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Barriers to other technologies / existing power plants	Yes	BiH generation mix consists mainly of HPPs and inflexible coal-fired TPPs. HPPs are affected by the hydrological conditions, which are less favourable during late spring to early autumn months. One PSHPP (Capljina) has very limited number of operational hours due to lack of water, that is preferably used to feed other HPPs system (HPP on the Trebjesnica river and HPP Dubrovnik).

6.3 Georgia

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Georgia is currently drafting its NECP, for which the legal basis is adopted.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	Partially	Prosumers not explicitly defined, but primary legislation (the Law on Electricity and Natural Gas) defines a micro power plant as a renewable source of power with the capacity not exceeding 100 kW[112], possessed by a retail customer and connected to the electricity distribution network at the consumption point of the retail customer. Requirements for micro power plants have been moved to the rules of the retail market and the rules of the distribution network, which define them as: An electricity generation facility owned / used by a customer or a group of customers, which uses renewable energy sources, is connected to the electricity distribution network and whose installed capacity does not exceed 500 kW.
	Aggregators not defined in regulatory framework	Yes	Regulatory framework does not make it possible for aggregators to be active in the market
	Absence / issues with Day-ahead market	Yes	The day-ahead market is not yet operational. Launch postponed until Q3 2022.
	Absence / issues with Intra-day market	Yes	The intra-day market is not yet operational. Launch postponed until Q3 2022.
	Absence / issues with Balancing market	Yes	The balancing market is not yet operational. Launch postponed until Q3 2022.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	No DA, ID or balancing market in place.
	Price caps and other restrictions on wholesale markets not indicated above	-	No DA, ID or balancing market in place. Price caps are planned with the launch of the market.
	End-user price regulation / other interventions	Yes	End-user electricity prices for household consumers were regulated in 2020. In Georgia all non-household customers had the possibility to be supplied at regulated prices. 0 metering points supplied at non-regulated electricity prices in 2020.
	Lack of time-differentiated retail commodity prices	Yes	NA
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	Partially	TSOs not completely unbundled, unbundling of the two DSOs completed.
	Electricity wholesale market concentration	Partially	Less concentrated than other CPs, generation top companies /CR3 had 42% of the market, nevertheless few Generation companies operate under the PSO obligations.
	Limited/no competition in electricity retail markets	Yes	High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. 2 retailers exist.

[112] The installed capacity does not exceed 100 kW, unless a higher upper limit is set by the Commission; In addition, even in such a case, the upper limit should not exceed 500 kW

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	Partially	Well interconnected with neighbours (Russia, Armenia, Turkey), with an interconnectivity level of 48% in 2020, meaning interconnector's total net transfer capacity is equivalent to half the total installed generation capacity. However not interconnected with other Contracting Parties or EU Member States.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The available NTC of the interconnectors is relatively low, with net transfer capacities amounting to only 51% of the nominal transmission capacities. In case of Georgia, despite low or high interconnection capacity, it should be noted that it may not benefit in terms of flexibility form its neighbours due to their non-consistent regulatory frameworks (no obligation on competitive markets and use of interconnection capacity).
	Other network capacity, capacity allocation and congestion management issues	Partially	Georgia has strong interconnections with its neighbouring countries (except Armenia with only one 220 kV line). However, the country is situated in between three synchronous areas and the Georgian internal network cannot fully support a very high level of exchanges. Since GSE heavily restricts permitted loading of the existing 500 kV lines to Russia and Azerbaijan, the exchange possibilities between Georgia and Russia/Azerbaijan are limited, thus potentially creating needs for the construction of additional cross-border lines. Revitalisation of the existing 500 kV lines should also be considered in order to increase the transmission capacities of Georgia toward its neighbours. Capacity allocation is implemented only on the borders with Turkey, but in a non-compliant manner. General principles on congestion management, including the use of congestion revenues, have not been implemented yet.
	Inadequate network tariff design	Yes	Time-of-use tariffs not in place
	Lack of smart metering for low voltage-connected users	No	In Georgia, all prosumers are required to have bi-directional meters installed in their premises. Company has a commitment to install meters for micro power plants, as required by the Distribution network rules - Article 22, paragraph 10c.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	Yes	No incentives available
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	-	NA
	Subsidisation of fossil-based / other power generation	-	NA
	Market distortions due to support schemes	Partially	All Contracting Parties, except Albania and Serbia, have introduced two self-consumption schemes for small-scale renewable energy technologies, namely net metering and net billing. FiP expanded to producers above 5 MW.
Technology-specific barriers	Other barriers to demand response	Yes	Respective regulatory framework does not make it possible for demand response to be actively engaged in the market activities
	Other barriers to Gas-fired generation	-	NA
	Other barriers to EV smart charging / vehicle-to-grid	Partially	Some e-mobility issues defined in legislation. NRA is authorized to set connection costs for recharging infrastructure.
	Other barriers to Storage (front / behind-the-meter)	Yes	Little progress observed regarding the development of energy storage technologies and flexible generation capacity. Relevant government support and the appropriate legislative provisions have also not been provided.

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Barriers to other technologies / existing power plants	-	NA

6.4 Kosovo*

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Kosovo* is currently drafting its NECP. The legal basis for the NECP is under development. NECP drafting process is prolonged until the Energy Strategy 2022-2031 is approved. Furthermore, based on the latest developments of the Ministerial Council of the Secretariat of the Energy Community, the first draft will be approved by Q2 2023, while the final draft will be approved in Q2 2024 (Decision of the Ministerial Council of the Secretariat of the Energy Community dated 30.11.2021). Kosovo* is in the process of reviewing the Energy Strategy 2017-2026 which will cover the period 2022-2031. Revised Energy Strategy document is planned to be approved by the Government by the end of June 2022
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	No	The concept of a prosumer was defined in the Rulebook on Support Scheme for Renewable Energy Sources.
	Aggregators not defined in regulatory framework	Yes	No definition of aggregators in the national regulatory framework or other provision related to aggregators has been identified.
	Absence / issues with Day-ahead market	Yes	Establishment of an operational day-ahead market is delayed - launched expected in Q1 2023 after ALPEX operationalisation in AL.
	Absence / issues with Intra-day market	Partially	There is no organised intraday market. Network users can submit to TSOs intraday schedules, and conduct bilateral trades after closure of the day-ahead market, up to H-2.
	Absence / issues with Balancing market	Partially	There is a market-based imbalance price set by KOSTT. Balancing cooperation with Albania for aFRR and mFRR, Albania-Kosovo* (AK) control block. There are limitations in terms of competition, but mechanism works perfectly given the circumstances.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Market coupling depends on the establishment of organised DA and ID markets. Establishment of a DA market and its coupling with Albania is delayed and should follow two months after the Albanian DA market goes live.
	Price caps and other restrictions on wholesale markets not indicated above	-	No DA or ID market established. ALPEX, the Albanian power exchange is responsible for setting up the DA and ID markets in Kosovo* as well as coupling the two markets.
	End-user price regulation / other interventions	Yes	End-user electricity prices continue to be regulated. All non-household customers that are connected to the DSO network have regulated prices, and customers that are connected to the TSO network (220 kV and 110 kV voltage level) are supplied under non-regulated prices.
	Lack of time-differentiated retail commodity prices	Partially	There have been limited measures to ensure that tariffs allow suppliers to improve consumer participation in system efficiency including demand response or that network tariffs support the development of demand response services. As of 9 February 2022, however, there are new tariffs, including also change of structure. There is a day-night tariff (no seasonality) and the block-tariff is introduced for HH Consumption above 800kW charged at higher price.
	Lack of / non-compliant TSO or DSO unbundling	No	TSO and DSO are both unbundled.

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Market structure and performance	Electricity wholesale market concentration	Yes	Generation top company had 95% of the market in 2020, a high level of concentration. However, important to note that 2020 was a year with low consumption and high KEK production, thus a more appropriate figure is circa 80-85% with the rest covered by small generations and import. Competition in the wholesale market is hindered by a 'bulk supply agreement' between KEK and KESCO, through which KEK sells its output to KESCO to the extent it needs it to supply its public service portfolio.
	Limited/no competition in electricity retail markets	Yes	High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. 1 retailer. Opening of retail markets was postponed for the 4th consecutive year.
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Well interconnected with neighbours, with an interconnectivity level of 106% in 2020.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The availability of the interconnectors is relatively low, with net transfer capacities amounting to only 23-25% of the nominal transmission capacities. This restricts the possibility of cross-border integration of flexibility sources. However, it is important to note that the NTC calculation methodology and approval is based on the lowest value calculated by interconnected TSOs, meaning the limitation of NTCs depends on the NTC evaluation of interconnected TSO-s, where the smallest value is approved. In addition, there is a lack of coordinated capacity calculation and coordinated process, in particular in the short term.
	Other network capacity, capacity allocation and congestion management issues	Partially	Forward and daily cross-border capacities are allocated through SEE CAO, except with Serbia, where capacities are not offered to the market at all - this is a concern for market participants and also a complaint which KOSTT filed with ECS. Intraday capacity is allocated bilaterally.
	Inadequate network tariff design	Yes	Time-of-use tariffs not in place
	Lack of smart metering for low voltage-connected users	Partially	The residential smart meter penetration was 11%.[113] All prosumers are required to have bi-directional meters installed in their premises. Smart metering is a pre-condition for the development of behind-the-meter flexibility sources.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	Yes	Due to the small number of smart meters installed, there are no load profiles for categories of consumers therefore it is difficult for network operators to target consumers that could be used for demand side response.
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	No	According to legislation in force, there are no taxes foreseen for self-generation, neither for storage.

[113] ECRB (2021). Market Monitoring Report Gas and Electricity Retail Markets in the Energy Community. Reporting period 2020.

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Subsidisation of fossil-based / other power generation	Yes	12.7M EUR of direct subsidies provided to coal/lignite electricity producers in 2018/2019, or an equivalent average of 1.22 EUR/MWh.[114] This affects the competitiveness of flexibility sources. KEK has received no grants from the Government of Republic of Kosovo* since the year 2010, neither of operating expenditures nor for financing of non-current assets. The records presented in the financial statements relate to proportionate registration as revenues and expenditures of the portion of annual depreciation for the assets which are financed in year 2010, for the same amount
	Market distortions due to support schemes	No	Feed-in tariff as a support scheme is finished by December 2020, therefore the only support schemes remains RES generating facilities under regulated framework and self-consumption schemes for small-scale renewable energy technologies, namely net metering. The installed capacity of the self-consumption generator shall not exceed 100kW and the voltage level is 0.4 kV. Renewable Law is being drafted to enforce market based mechanisms for supporting renewables.
Technology-specific barriers	Other barriers to demand response	Partially	TSO makes use of load shedding for balancing as a last resort measure, but with no commercial incentive. Articles 15(4) and 15(8) of the EE Directive (EED) have been transposed into primary legislation; but the regulator has not yet adopted required secondary legislation to enable implementation. The DSR was not properly addressed under the NEEAP nor under EED progress reports.
	Other barriers to Gas-fired generation	Yes	Kosovo* is still highly reliant on its two lignite power plants that supply 95% of Kosovo*'s electricity generation. On the other hand there is no gas market, infrastructure or supplies of natural gas that could ease dependency on these plants, and the debate is still ongoing about gas access. Supply routes could be established with North Macedonia and Albania. The recommendation from the Gas Development Plan, North Macedonia-Kosovo* Gas Interconnection Pipeline: Feasibility Study and the new Strategy of Energy 2022-2031 will determine the policy and measures regarding natural gas. Discussions about gas-fired power plant intended primarily for balancing are ongoing but decisions will be made once the gas master plan and the feasibility study for the North Macedonia-Kosovo gas interconnection pipeline are finalized.
	Other barriers to EV smart charging / vehicle-to-grid	Yes	No e-mobility issues defined in legislation. No current primary or secondary national legislation that deals with building publicly accessible recharging infrastructure for EV.
	Other barriers to Storage (front / behind-the-meter)	Yes	Current primary and secondary national legislation has not specified types of storage facilities, however it is specified that the owner of such facility cannot be TSO.
	Barriers to other technologies / existing power plants	Yes	Existing coal-fired units are inflexible and there are no other more important production facilities. Hydro power plants are small and of the run-of-river type so they cannot provide flexibility services.

[114] ECS (2020), Investments into the past - An analysis of Direct Subsidies to Coal and Lignite Electricity Production in the Energy Community Contracting Parties 2018-2019

6.5 Moldova

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	In 2013, Moldova introduced its updated National Energy Strategy (NES) 2030. Complementing the NES are the National Energy Efficiency Action Plans (NEEAPs) 2013-15, 2016-18, 2019-21 and the National Renewable Energy Action Plan (NREAP) 2013-20. The NES, NEEAPs and the NREAP were designed consistent with Moldova's commitments under the Energy Community Treaty. Moldova fully transposed its Third Energy Package requirements. Currently drafting its NECP. The development of the legal basis for the NECP is planned. Therefore, there is a lack of strategy guidance for the energy sector.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	Partially	The concept of a prosumer is not explicitly defined in legislation. However, according to Art. 39 (1) of the Law on promoting the use of RES, a final consumer, who owns a power plant, which produces electricity from RES for his own use and who has signed with the supplier a contract for the supply of electricity at a regulated price, has the right to deliver the surplus to the network and apply the net metering mechanism.
	Aggregators not defined in regulatory framework	-	NA
	Absence / issues with Day-ahead market	Yes	The day-ahead market is not yet operational.
	Absence / issues with Intra-day market	Yes	There is no intra-day market. Network users cannot/do not submit to TSOs intraday schedules, nor conduct bilateral trades after closure of the day-ahead market.
	Absence / issues with Balancing market	Yes	No balancing market or mechanism in place. Cross-border balancing mechanism seen as a medium term objective, with the need for implementation of imbalance netting and the assessment of potential for exchange of other balancing reserves/services. There is a monthly balancing performed implicitly through bilateral contracts. Balancing mechanism postponed again due to Russian aggression in Ukraine.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Market coupling depends on the establishment of organised DA and ID markets. It is considered a long term objective.
	Price caps and other restrictions on wholesale markets not indicated above		No DA, ID or balancing market established.
	End-user price regulation / other interventions	Yes	End-user electricity prices for household and small consumers were regulated in 2020. Furnizare Energie Electrică Nord (state-owned) and Premier Energy Furnizare (privately owned), both sell electricity at regulated prices and act as suppliers of last resort in their respective supply areas.
	Lack of time-differentiated retail commodity prices	-	NA
	Lack of / non-compliant TSO or DSO unbundling	Partially	The lack of unbundling of electricity TSO is subject to an infringement case of the Energy Community. Unbundling of the distribution system operators is completed.

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Market structure and performance	Electricity wholesale market concentration	Yes	Generation CR3 of 79+15+2%. The entry into force of the wholesale electricity market rules, initially envisaged for 2 October 2021, was postponed until 1 April 2022. In its current state, the electricity wholesale market suffers from a lack of competition, and is mainly limited to imports from Ukraine[115] or the Moldavskaya GRES (MGRES) plant situated in Transnistria, which together supplied 81% of electricity demand in 2019 and 2020.
	Limited/no competition in electricity retail markets	Yes	High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. 7-25 retailers exist. Despite the Electricity Law granting switching eligibility to all customers, the competitiveness of retail suppliers is hampered because they only have limited access to wholesale supplies of electricity. As a result, there are very few retail suppliers for consumers to choose from. In 2019, the share of electricity sold by retailers on a competitive market was 7.4%, with this share then increasing to about 9.6% in 2020.
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Limited interconnectivity level up to 31% (import) and 46% (export) in 2020. Until recently, Moldova's electricity grid was synchronously interconnected with Ukraine's Integrated Power System (IPS) and, in turn, Russia's Unified Power System (UPS) but not with Romania (part of ENTSO-E's Continental Europe Synchronous Area, with stricter regulations). As of 16 March 2022 an emergency synchronisation of the continental European power system with the power systems of Ukraine and Moldova (IPS) has commenced following an urgent request by Ukrenergo and Moldova upon the Russian invasion of Ukraine[116], which will increase transmission capacities and transform electricity markets in both countries.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The available NTC of the interconnectors is relatively low, with net transfer capacities amounting to only 31%/46% of the nominal transmission capacities. This restricts the possibility of cross-border integration of flexibility sources. Efficient use of cross-border capacity is a short term objective and requires the cooperation on cross-border capacity calculation and market-based and non-discriminatory cross-border capacity allocation (explicit).
	Other network capacity, capacity allocation and congestion management issues	Partially	Moldova and Ukraine are mutually very strongly interconnected but import to Moldova from Ukraine is heavily restricted, thus negatively influencing market competition in both countries. The implementation of cross-border capacity allocation on the Moldovian-Ukrainian border has been agreed by TSOs, agreements and allocation rules were expected in Q1 of 2022.
	Inadequate network tariff design	Yes	Time-of-use tariffs not in place
	Lack of smart metering for low voltage-connected users	No	In Moldova, there are no specific requirements regarding the meters but prosumers should have a meter which is capable to count both consumed and injected electricity
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	-	NA
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	-	NA

[115] Ukrainian companies have regained access to the Moldovan market after the lifting of electricity export restrictions imposed by Ukraine in November 2014 due to the unavailability of coal-fired power plants in Eastern Ukraine.
[116] See more under *Ukraine*

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Subsidisation of fossil-based / other power generation	-	NA
	Market distortions due to support schemes	Partially	Moldova has introduced two self-consumption schemes for small-scale renewable energy technologies, namely net metering and net billing. Policymakers should ensure a level playing field in the energy sector by phasing out tax distortions created by reduced VAT on natural gas and zero VAT on electricity and heat for residential consumers. Renewable Law being drafted to enforce market-based mechanism for supporting renewables.
Technology-specific barriers	Other barriers to demand response	Yes	The regulatory framework does not provide for the participation of demand response in the provision of balancing and other ancillary services.
	Other barriers to Gas-fired generation	Yes	Natural gas accounts for more than half of the country's total primary energy supply, with all of Moldova's consumption being met through imports, mainly from Russia. Trans-Balkan route expected to stimulate trading with the South-Eastern European region.
	Other barriers to EV smart charging / vehicle-to-grid	Partially	No e-mobility issues defined in legislation, though special laws are in preparation. There are tax advantages for EV owners but building of recharging points is on a voluntary base.
	Other barriers to Storage (front / behind-the-meter)	-	NA
	Barriers to other technologies / existing power plants	Yes	The only power plant providing balancing service is MGRES. Other CHP facilities are inflexible. No other power plants within the country which may participate at the balancing market.

6.6 Montenegro

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Montenegro is currently drafting its NECP, for which the legal basis is adopted. There is an Energy Development Strategy in place until 2030, as well as a National Renewable Energy Action Plan by 2020.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	No	Energy Law annexed in 2020 (Article 96) defines prosumer as a final customer that generates electricity from RES or High-Efficiency Cogeneration where installed capacity is limited to predefined connection capacity as consumer.
	Aggregators not defined in regulatory framework	Yes	The terms Aggregation and Independent aggregator have been introduced by 944/2019 Directive Common Rules for Internal Market for Electricity. However, the Clean Energy Package has not been transposed in primary legislation in the CP's. There are no provisions in force that regulate the aggregators. Related to Demand response, there are provisions defined in Methodology for ancillary services.
	Absence / issues with Day-ahead market	Yes	The day-ahead market is not yet operational.
	Absence / issues with Intra-day market	Yes	The intra-day market is not yet operational.
	Absence / issues with Balancing market	No	Balancing market is competitive and functional, but the price of balancing reserve is still regulated.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Market coupling depends on the establishment of organised DA and ID markets.
	Price caps and other restrictions on wholesale markets not indicated above	-	No DA or ID or market established
	End-user price regulation / other interventions	Partially	Increase of end-user electricity prices for households has been limited in 2020. However in Montenegro, about 42% of non-household customers were supplied at un-regulated prices who consumed almost 95% of electricity consumed by all non-household customers.
	Lack of time-differentiated retail commodity prices	No	There are two tariffs defined, covering two different periods of a day
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	No	The TSOs and DSOs are unbundled.
	Electricity wholesale market concentration	Yes	Wholesale market is open for competition and formally deregulated. Incumbent/Generation top company however had 84% of the market.
	Limited/no competition in electricity retail markets	Yes	High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. Only one active retailer, though there are five more licensed retailers (suppliers).

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Well interconnected with neighbours, with an interconnectivity level of 210% in 2020, meaning interconnector's total net transfer capacity is equivalent to double that of the total installed generation capacity. In reference and RES scenarios, ME-IT interconnection could face some congestion in 2050.[117]
	Existing interconnector capacity is not (sufficiently) made available to the market	Partially	The availability of the interconnectors is relatively low, with net transfer capacities amounting to only 37-38% of the nominal transmission capacities. This restricts the possibility of cross-border integration of flexibility sources. Nonetheless, 74-72% of the Total Available Capacity was made available to market participants in 2020. Efficient use of cross-border capacity requires the cooperation on cross-border capacity calculation and market-based and non-discriminatory cross-border capacity allocation.
	Other network capacity, capacity allocation and congestion management issues	-	NA
	Inadequate network tariff design	No	Time-of-use tariffs are in place, based on methodologies for determining regulated revenue and prices for using transmission and distribution systems
	Lack of smart metering for low voltage-connected users	No	The residential smart meter penetration was 83%.[118] In Montenegro, all prosumers are required to have bi-directional meters installed in their premises.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	No	There is no explicit incentive, but according to Methodology for setting prices, deadlines and conditions for provision of ancillary and balancing services, providers of these services in Montenegro are all electricity producers connected to the transmission system, except for privileged producers, as well as end customers who have appropriate technical and technological capabilities and business interest in providing such services. In addition to this, all cost that derive from provision of mentioned services are covered through allowed revenues of system operators determined by NRA. Rules governing preparation and approval of network development and investment plans prescribe that flexibility is taken into account in the process of approval of investments.[119]
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	No	No taxes on self-consumption
	Subsidisation of fossil-based / other power generation	Yes	1,14M EUR or 0,4 EUR/MWh of direct subsidies provided to coal/lignite electricity producers in 2018/2019

[117] Ecorys et al. (2021), Study on CESEC cooperation on electricity grid development and renewables
[118] ECRB (2021). Market Monitoring Report Gas and Electricity Retail Markets in the Energy Community. Reporting period 2020.
[119] https://regagen.co.me/wp-content/uploads/2021/12/20210527_Metodologija_za_utvrdjivanje_cijena_rokova_i_uslova_za_pruzanje_pomocnih_usluga_i_usluga_balansiranja_prenosnog_sistema_elektricne_energije.pdf
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Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Market distortions due to support schemes	Partially	All Contracting Parties have introduced two self-consumption schemes for small-scale renewable energy technologies, namely net metering and net billing. Administratively-set net metering in place for small projects, with tenders for larger projects. In Montenegro, two support schemes are in place: privileged producers status scheme and prosumers scheme. Prosumers scheme or self-consumption scheme have been introduced as net-metering and net-billing.
Technology-specific barriers	Other barriers to demand response	No	Provides for the participation of demand response in the provision of balancing and other ancillary services.
	Other barriers to Gas-fired generation	Yes	The country is not connected to natural gas systems and does not have a gas market, but could provide facilities for small quantities of LNG to be further transported by railway.
	Other barriers to EV smart charging / vehicle-to-grid	Yes	No e-mobility issues defined in legislation.
	Other barriers to Storage (front / behind-the-meter)	-	NA
	Barriers to other technologies / existing power plants	-	NA

6.7 North Macedonia

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	No	National energy strategy adopted. Draft NECP submitted to the Secretariat. In accordance with the Article 12 of the Energy law ("Official Gazette of the Republic of Macedonia" No. 96/18 and "Official Gazette of the Republic of Northern Macedonia" No. 96/19) the Ministry of Economy prepared the Program for implementation of the energy development strategy 2021-2025. The Energy development strategy of the Republic of North Macedonia until 2040, was adopted in December, 2019 year.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	Yes	The concept of a prosumer was defined in the Rulebook on renewable energy sources, Article 4(1) ("Official Gazette of the Republic of North Macedonia" No. 96/2018), and is also included in Article 68, draft distribution grid code. According to the new balancing rules adopted by MEPSO in August 2019, it is possible for consumers to appear in the role of balance service provider. However, according to feedback received, one of the biggest regulatory barriers for deployment of households - prosumers on the grid is the inapplicable provision in the Rulebook on RES, according to which the status of consumer-producer can be acquired only if the household/legal entity is supplied with electricity from a supplier other than the universal supplier though at the moment the only household supplier is the universal supplier. The Ministry of Economy is working on changing and amending the current Rulebook on renewable energy sources, with the aim households and industrial facilities to be able to sell surplus electricity to the universal supplier.
	Aggregators not defined in regulatory framework	Partially	Virtual producer will be defined with the amending of the Electricity Market Rules.
	Absence / issues with Day-ahead market	Yes	The day-ahead market is still not operational.
	Absence / issues with Intra-day market	Yes	The intra-day market is still not operational.
	Absence / issues with Balancing market	No	Balancing market is operational. MEPSO procures both the balancing reserve and balancing energy in a competitive procedure, although only with two registered balancing service providers.
	Absence of DA and/or ID market coupling, balancing market integration	Partially	Draft NECP 2020 includes plans for coupling with IBEX (Bulgarian day-ahead market) and participation in the initiative for establishing a regional electricity market. However, Macedonia is still missing a national power exchange that will determine reference price as a prerequisite for market coupling with neighbors. Network users could in 2019 access cross-zonal capacities in intra-day timeframe on borders with Serbia/Kosovo*. According to TRINITY[120], the DA market is coupled with all neighbouring countries and the ID market is coupled only with Serbia so far.
	Price caps and other restrictions on wholesale markets not indicated above	Partially	There are obstacles in purchasing balancing services from other countries because of the difficulties with the VAT Law.[121] The country is in the process of solving this obstacle. The Macedonian TSO is in the process of implementing Imbalance Netting within the SMM (Serbia-Macedonia-Montenegro) Block.

[120] Trinity (2020), TRansmission system enhancement of regIoNal borders by means of IntelligenT market technology - D2.2. Boundary conditions report
[121] Trinity (2020), TRansmission system enhancement of regIoNal borders by means of IntelligenT market technology - D2.2. Boundary conditions report

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	End-user price regulation / other interventions	Yes	End-user electricity prices for household and other small consumers are regulated. In the regulated supplier (EVN HOME DOO Skopje) there is a continuous reduction of the total purchased quantities of electricity[122], which is correlated with the process of full liberalization of the electricity market.
	Lack of time-differentiated retail commodity prices	Partially	Draft NECP considers introduction of real-time price signals that will encourage the consumers to have a pro-active role in balance services, thus increasing the capacity of demand side response. At the moment, there are no real-time price signals.
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	No	With the adaptation of the Energy Law in 2018, the overall electricity market became liberalized. TSOs and DSOs are unbundled.
	Electricity wholesale market concentration	Partially	Generation CR2 of 71+21%. Average share of suppliers and traders on the wholesale market electricity, 2018: top 5 shares of 32.3%, 21.1%, 13.8%, 13%, 6.4%. 2020 was the first year when electricity consumption in the open market was greater than the electricity consumption in the regulated market and it was 52.24% of the total gross electricity consumption. This trend is expected to continue in the future. In 2020, the number of the completed procedures on Supplier Switch was 16.200, indicating an increase by 124,2 % compared to 2019, when the number of completed procedures on electricity Supplier Switch was 7.231.
	Limited/no competition in electricity retail markets	Yes	Retail market open for competition. High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 88% for whole market and at or near 100% for residential sector. 7-25 retailers exist.
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Well interconnected with neighbours, with an interconnectivity level of 55% in 2020, meaning interconnector's total net transfer capacity is equivalent to half the total installed generation capacity. The country plans to improve the currently high level of connection, by finishing the new interconnection with Albania (as a project on the PECI List), thus enhancing the interconnectivity of the region. In reference and RES scenarios[123], BG-MK interconnection could face structural congestion in 2030 and 2050. However, this may be due to an unnecessarily low NTC value, meaning that the interconnection might not be in fact congested.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The availability of the interconnectors is relatively low, with net transfer capacities amounting to only 20-22% of the nominal (thermal ratings of the lines) transmission capacities. Also, only 25-34% of the Total Available Capacity was made available to market participants in 2020 (ECRB, 2021, Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020). This restricts the possibility of cross-border integration of flexibility sources.

[122] According to the Energy Law (dated 2018), the producer with the largest installed capacity in MK (ESM) shall provide to universal supplier (EVN Home) these quantities of electricity: in 2019, min 80 % of total needs of the supplier; in 2020, min 75 % of total needs of the supplier; in 2021, min 70 % of total needs of the supplier; in 2022, min 60 % of total needs of the supplier; in 2023, min 50 % of total needs of the supplier; in 2024, min 40 % of total needs of the supplier; in 2025, min 30 % of total needs of the supplier.
[123] Ecorys et al., 2021, Study on CESEC cooperation on electricity grid development and renewables

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Other network capacity, capacity allocation and congestion management issues	No	The new Grid Code for electricity transmission (released in Jan, 2022) is in full compliance with EU Grid Codes. D MEPSO Skopje, allocates cross-border transmission capacities in accordance with the Rules on Allocation of Cross-Border Transmission Capacities ("Official Gazette of the Republic of North Macedonia" no. 228/19 and "Official Gazette of the Republic of North Macedonia" no. 294/2020). The Energy Regulatory Commission approves the Rules before they enter into force. In accordance with these Rules, cross-border capacities can be allocated via coordinated auction, joint auction with neighboring electricity transmission system operators and one share (50%) of the available cross-border transmission capacity can be allocated unilaterally. In the border with Greece and in the border with Kosovo*, AD MEPSO Skopje conducts coordinated auction through the Coordinated Auction Office in Southeast Europe in Podgorica, Montenegro. In the border with Bulgaria and Serbia, joint auctions are performed in an annual, monthly, daily, and intra-day level.
	Inadequate network tariff design	Yes	Time-of-use tariffs are not in place, but it is applied the peak tariff and the off peak tariff.
	Lack of smart metering for low voltage-connected users	Yes	All prosumers are required to have bi-directional meters installed in their premises. The Secretariat recommends that deployment of smart metering is more explicitly addressed in the final NECP. Smart metering is a pre-condition for the development of behind-the-meter flexibility sources.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	No	Development plans of the transmission grid relies on flexibility sources both from national and regional power systems.
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	No	With the Program for promotion of renewable energy sources and stimulation of energy efficiency in the household for 2021 the Ministry of Economy provides reimbursement of part of the costs for purchase and installation of photovoltaic panels for generation of electricity up to 4 kW for own consumption for households, on a building on which they have the right of ownership or use.
	Subsidisation of fossil-based / other power generation	Yes	8.83M EUR of direct subsidies provided to coal/lignite electricity producers in 2018/2019, or an equivalent average of 0.64 EUR/MWh.[124] This affects the competitiveness of flexibility sources.
	Market distortions due to support schemes	No	Two self-consumption schemes for small-scale renewable energy technologies introduced, namely net metering and net billing. Administratively-set net metering in place for smaller projects, with FiP for larger projects. The preferential tariff (introduced 2007) and the premium tariff (introduced by the Law on Energy, 2018) are available as measures to support electricity production from RES. The preferential producers operating under preferential tariff are guaranteed with the tariff of each kWh produced electricity under which the Electricity Market Operator is obliged to purchase the total of electricity produced by the preferential producers in a period of 15 to 20 years, depending on the type of the Power Plant. The benefit for the preferential producers that use the preferential tariff is that the electricity market operator takes the balance responsibility for these producers. The Decree on the measures to support the electricity production from renewable energy sources, establishes the types of technologies awarded with preferential tariff, the special criteria to be fulfilled by the Power Plant in order the producer to obtain the status of preferential producer, the upper limit of the installed capacity in the Power Plant. The premium tariff represents an additional amount out of the price that the preferential producer has achieved by selling the produced electricity in the electricity market. The preferential producer that uses premium tariff is chosen via tender procedure with auction, carried out by the Ministry of Economy.

[124] ECS (2020), Investments into the past - An analysis of Direct Subsidies to Coal and Lignite Electricity Production in the Energy Community Contracting Parties 2018-2019

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Technology-specific barriers	Other barriers to demand response	Yes	North Macedonia does not provide the right conditions for the participation of demand response in the provision of balancing and other ancillary services. The draft law on Energy Efficiency (to be adopted), transposes only partially Article 15 of the EE Directive. This draft law will also regulate aggregators and smart meters. At the moment, demand response providers are excluded from participation due to lack of necessary framework. Pursuant to draft Law on Energy Efficiency, the regulator shall adopt tariffs and measures to enable the participation of the DSR.
	Other barriers to Gas-fired generation	Yes	Gas volumes consumed are modest and imported from Russia through an interconnector with Bulgaria. Supply is based on contracts with Gazprom and its affiliates.
	Other barriers to EV smart charging / vehicle-to-grid	Partially	No e-mobility issues defined in legislation but there is a national action plan for the introduction of recharging infrastructure for EVs and some issues are stipulated in the distribution grid code. NRA is authorized to set connection costs for recharging infrastructure. The Energy Strategy envisages introduction of a significant share of electric vehicles in the system, as a way of increasing the RES share in the transport and increasing the capacity of energy storage. In order to efficiently integrate them in the system, this process has to be accompanied by improved demand response capabilities, the introduction of real-time price signals and smart grids. In this regard, MEPSO has seriously considered these opportunities and has already made analyses within two projects concerning EV integration and demand response.
	Other barriers to Storage (front / behind-the-meter)	-	NA
	Barriers to other technologies / existing power plants	Yes	According to feedback received, there are long and complicated procedures for the implementation of large energy investments (for example the planed pumping accumulation hydropower plant Chebren), especially in the part of land expropriation which is a prerequisite for obtaining a building permit or concluding Public Private Partnership. In the future, this obstacle is expected to be overcome with the already adopted Law on Strategic Investments.

6.8 Serbia

	Barrier	Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Serbia is currently completing its NECP. The legal basis for the NECP is adopted. The preparation of the Development Energy Strategy of the Republic of Serbia until 2040 with projections until 2050 is also in its final phase. Once they are adopted, these strategic documents will set the direction, measures and targets for implementing the green energy transition and define the guidelines for the development of the energy sector.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	No	The concept of a prosumer was defined in the new renewable energy law. The 2021 "Decree on the criteria, conditions, and the method of billing between prosumers and suppliers" streamlined the process to become a prosumer.
	Aggregators not defined in regulatory framework	No	The figure of the aggregator was defined in the 2021 Energy Law amendments
	Absence / issues with Day-ahead market	No	The day-ahead market is operational. Volumes traded reached 10% of electricity supplied to end-users in 2020. (ECS, 2021, Annual Implementation Report)
	Absence / issues with Intra-day market	Partially	There is no organised intraday market. Network users can submit to TSOs intraday schedules, and conduct bilateral trades after closure of the day-ahead market (ECS, 2019, State of electricity intraday markets in the Energy Community).
	Absence / issues with Balancing market	Yes	A balancing market was established in 2013. However, ESP remains the dominant balancing service provider and the prices of balancing reserves are regulated (Energy Community Secretariat (2021) Annual Implementation Report). For producers under the FIT scheme, there is no balancing responsibility obligation by law (E3-Analytics, 2020)
	Absence of DA and/or ID market coupling, balancing market integration	Yes	The legal basis for market coupling is defined in the Serbian Energy Law and Serbia participates in several market coupling initiatives, but there is no market coupling with neighbouring countries yet. Balancing cross-border cooperation is restricted to bilateral exchanges with TSOs from Bosnia and Herzegovina, Montenegro, Hungary and Romania (ACER and CEER, 2021, MMR 2020 - Electricity wholesale volume). TSO EMS is a non-operational member of the IGCC imbalance netting project with a forecast to connect to the platform in April 2022 (ENTSO-E). EMS also has the status of an observer in the MARI project (Republic of Serbia, 2019, SoS statement)
	Price caps and other restrictions on wholesale markets not indicated above	Partially	Prices in DA market are limited to 0 to 3000 EUR/MWh, which is appropriate (SEEPEX, 2021) However, balancing reserve prices are regulated, with EPS constituting the sole balancing service provider (see section above).
	End-user price regulation / other interventions	Yes	End-user electricity prices for household consumers were regulated in 2020 (ACER retail MMR, 2021). Recently, due to supply crisis, the prices for other consumers were limited to 75 €/MWh until 30 June 2022 in line with the Government's recommendation
	Lack of time-differentiated retail commodity prices	No	Time-of-use tariffs (3 periods, regulated) for households and small customers are available (AERS, 2021). However, this 3-tariff system will not help flexibility issues to be resolved as the periods of different tariffs are related to the load with an intention to make a load duration curve more flat.
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	Partially	The distribution system operator was unbundled in 2021, but the transmission system operator EMS is not unbundled in line with the ECS opinion (ECS, 2021, Implementation report). This is disputed by the Serbian government and energy regulator.
	Electricity wholesale market concentration	Yes	EPS had 96% of the generation in 2020, a high level of concentration. The day-ahead market CR3 was 34% in 2020, the CR7 of 66% (ACER MMR, 2021).

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Limited/no competition in electricity retail markets	Yes	Prices of universal supply to households and small customers are regulated at the level that does not provide an incentive for customers to switch from the incumbent suppler. High retail market concentration leads to lack of competitive pressure, which hampers development of retail market and thus of prosumers. CR3 >90% for whole market and at or near 100% for residential sector. 7-25 retailers exist (ACER, 2021, retail MMR)
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	No	Serbia is well interconnected, with an interconnectivity level of 50% in 2020 (ECS, 2021, Electricity Interconnection Targets in the Energy Community Contracting Parties). The large interconnection capacity may act as a deterrent to developing domestic sources of flexibility.
	Existing interconnector capacity is not (sufficiently) made available to the market	Yes	The availability of the interconnectors is relatively low, with net transfer capacities amounting to only 41-44% of the nominal transmission capacities (ECS, 2021, Electricity Interconnection Targets in the Energy Community Contracting Parties). Also, only 37-42% of the Total Available Capacity was made available to market participants in 2020 (ECRB, 2021, Annual Monitoring Report on activities related to cross-border transmission capacity in the Energy Community for the period of 2020). This restricts the possibility of cross-border integration of flexibility sources.
	Other network capacity, capacity allocation and congestion management issues	Partially	There may be domestic transmission constraints to integrating significant volumes of renewables to 2030.
	Inadequate network tariff design	No	Time-of-use tariffs are applied / possible. No other barriers identified in this aspect.
	Lack of smart metering for low voltage-connected users	Yes	The residential smart meter penetration was very low, at 0.9%.[125] Smart metering is a pre-condition for the development of behind-the-meter flexibility sources.
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	-	NA
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	Yes	Prosumers feeding-in electricity to the network need to pay VAT
	Subsidisation of fossil-based / other power generation	Yes	88.76M EUR of direct subsidies provided to coal/lignite electricity producers in 2018/2019, or an equivalent average of 1.92 EUR/MWh (ECS, 2020, Investments into the past - An analysis of Direct Subsidies to Coal and Lignite Electricity Production in the Energy Community Contracting Parties 2018-2019). This includes subsidies to mining coal used for other purposes as well as for electricity generation. This affects the competitiveness of flexibility sources.
	Market distortions due to support schemes	No	Net metering introduced in 2021 (ECS, 2021, Implementation Report). Both FiTs and FiPs exist, but the producer can use only one support mechanism for one production facility (AERS, 2021).
Technology-specific barriers	Other barriers to demand response	No	The market rules provide for the participation of demand response in the provision of balancing and other ancillary services The amendments to the Energy Law allow for the aggregators to enter the market. Article 15(8) of the EE Directive has not been transposed. The obligation to implement Directive 944/2019 for Energy Community CPs is until the end of 2023).
	Other barriers to Gas-fired generation	-	NA

[125] ECRB (2021). Market Monitoring Report Gas and Electricity Retail Markets in the Energy Community. Reporting period 2020.

Barrier		Is it a barrier?	Please provide details on the current situation and why it is a barrier (or not)
	Other barriers to EV smart charging / vehicle-to-grid	Partially	The Energy Law introduced the definition of charging point, secondary legislation is being developed.
	Other barriers to Storage (front / behind-the-meter)	No	The figure and responsibilities of the storage operator were defined in the 2021 Electricity Act amendments (sog.rs; Republic of Serbia)
	Barriers to other technologies / existing power plants	Yes	Serbian generation mix consists of mainly coal-fired units and large hydro power plants, with some gas fired units, small hydro, wind and solar power plants. Since the gas-fired capacity is small, flexibility services within the national borders may be provided by the hydro units only. Since their production is dependent on the hydrological conditions their support can be restricted during certain parts of a year.

6.9 Ukraine

	Barrier	Is it a barrier?	Please provide details
Strategy	Lack of long-term planning for the energy system / policy strategy for the development of flexibility sources	Partially	Ukraine is currently drafting its NECP. The legal basis for the NECP is adopted. In 2021, the regulator NEURC approved Ukrenergo's Report on Adequacy Assessment of the Generating Facilities of 2020[126], an important instrument to assess generation adequacy in Ukraine and enable necessary investments. More Generation Adequacy Reports are also available. In 2021 the latest Energy Security Strategy of Ukraine and Economic strategy of Ukraine till 2030 were published. Also the Second National Contribution under Paris Climate Agreement was adopted in 2021. The market design and responsibility of actors changes continuously, and can often be inconsistent. The New Energy Strategy up to 2035 has been published as well as an Action Plan for RES Development.
Regulation and market design	Prosumers / Self-consumption not defined in regulatory framework	No	Self-consumers are defined in the legislation. In 2019 non-household consumers (e.g. energy cooperatives) were also authorised to install renewable generation capacity of up to 150 kW (ECRB, 2020, Prosumers in the Energy Community).
	Aggregators not defined in regulatory framework	Yes	No definition of aggregation in the regulatory framework was identified.Further, there are no aggregators (as defined by the EU legislation). Consumers are represented only by suppliers.
	Absence / issues with Day-ahead market	Partially	DAM/IDM in operation. Average liquidity but shallow, but many restrictions/regulatory interventions. See details below. (ECS, 2021, Cross-border Trading in Ukraine - Roundtable on Electricity Supply and Trade in the New Market Model)
	Absence / issues with Intra-day market	Partially	DAM/IDM in operation. Relatively liquid, but many restrictions/regulatory interventions. See details below. (ECS, 2021, Cross-border Trading in Ukraine - Roundtable on Electricity Supply and Trade in the New Market Model)
	Absence / issues with Balancing market	Partially	Balancing market in operation (with the energy market being called balancing market and the reserve market being called the ancillary services market). Services are procured through competitive procedures. Qualification of providers to the ancillary services market is challenging as ancillary market is at the developmental stage, and thus market participants have limited experience with the qualification process (IEA, 2021, Ukraine Energy Profile). Following a technical assistance program that was initiated to promote qualification, improvements are still needed for a well-functioning AS market (USAID, 2020, A Year of Operation of the Competitive Wholesale Electricity Market in Ukraine) but some new AS providers and capacities were qualified by the TSO in 2021.
	Absence of DA and/or ID market coupling, balancing market integration	Yes	Ukrainian electricity markets are not coupled with neighbouring countries. Market and grid integration with [Continental Europe Synchronous Area] has been faster than initially planned: emergency synchronization with CESA has happened as of 16 March 2022, and trial synchronization of the Continental European Power System (CESA) with the power systems of Ukraine and Moldova has commenced following an urgent request by Ukrenergo and Moldova upon the Russian invasion of Ukraine[127]. Although trading is not happening yet, TSOs of Continental Europe are working with the two countries and regulators that are operating their respective power systems to assist in emergency needs.

[126] https://www.nerc.gov.ua/news/regulyator-zatverdiv-zvit-z-ocinki-vidpovidnosti-generuyuchih-potuzhnostej-dlya-pokrittya-prognozovanogo-popitu-elektro-ta-zabezpechennya-neobhidnogo-rezervu-2020
[127] https://www.entsoe.eu/news/2022/03/16/continental-europe-successful-synchronisation-with-ukraine-and-moldova-power-systems/

	Barrier	Is it a barrier?	Please provide details
	Price caps and other restrictions on wholesale markets not indicated above	Yes	There are price caps in the DA, ID and balancing markets in Ukraine, in ancillary service market which have been reviewed several times recently (Razumkov Centre, 2021). Public service obligations, PSO for nuclear and hydro generators, trading obligations of the guaranteed buyer and state-owned generators, and continuous changes to the market design (including regarding bilateral contracts) affect price formation.
	End-user price regulation / other interventions	Yes	End-user electricity prices for household and other categories of customers which are allowed to benefit from household prices are regulated.[128] For all other non-household customers prices were not regulated (about 8% of non-household customers who consumed more than 68% of the electricity consumed by all non-household customers). (ACER retail MMR, 2020; ECRB MMR 2021)
	Lack of time-differentiated retail commodity prices	No	(Regulated) time-of-use tariffs exist (CMS Law). Time-use tariffs approved by the CMU Resolution No.483 of 05.06.2019 [129] and CMU Resolution No.859 of 11.08.2021[130]
Market structure and performance	Lack of / non-compliant TSO or DSO unbundling	No	The transmission system operator was certified in December 2021, under ISO model with certain conditions. Distribution system operators are legally and functionally unbundled in compliance with the acquis (ECS, 2021, Implementation Report)
	Electricity wholesale market concentration	Yes	The generation CR3 was 63% in 2020. The day-ahead market CR3 was 53% in 2020, with companies with a <5% share having the remainder of the DA market (ACER MMR, 2021). Market concentration and the importance and opacity of the bilateral market affects market transparency, with concerns regarding market manipulation (Tetra Tech, 2020, A Year of Operation of the Competitive Wholesale Electricity Market in Ukraine; ECS, 2021, Cross-border Trading in Ukraine - Roundtable on Electricity Supply and Trade in the New Market Model). Two companies, Energoatom and DTEK, are in a pivotal position which means that their capacity is most of the time needed to meet the demand. Among the marginal cost plants, DTEK represents 2/3 of the production capacity. The only other company that owns a significant amount of coal fired power production, is Centerenergo (state-owned). In peak demand situations, smaller companies may also temporarily be in a pivotal position. Similarly, Ukrhydroenergo is providing much of the balancing power and is in a pivotal position regarding balancing markets. (Supponen, 2021, Reforming Ukraine's electricity market) Up until the synchronization of Ukraine's electricity system with CESA, market power in BEI of the main electricity supplier seemed to be significant (TetraTech, 2021, The Analysis on Market Power in Burshtyn Trading Zone) in no import periods. BEI does not exist anymore due to the synchronization. There is alleged opposition to the introduction of market integrity and transparency rules (Energy Security Strategy of Ukraine, 2021), currently several draft Laws are under consideration in the Parliament (Verkhovna Rada of Ukraine).
	Limited/no competition in electricity retail markets	Partially	Retail markets are competitive, with a CR3 of 30% for the whole market and of 28% for the residential sector (i.e. households), with 464 retailers present (ACER, 2021, retail MMR). Nonetheless, Supponen (2021) alleges "Retail sales are dominated by companies linked to the regional DSOs (distribution system operators), and it is not uncommon that power production cross-subsidises sales activities, because margins in the retail supply are generally small".

[128] Small non-household prices are not regulated, though they may use universal service supply (where the price is not regulated but calculated by the supplier following the methodology approved by the NEURC. https://www.nerc.gov.ua/acts/pro-zatverdzhennya-poryadku-formuvannya-tsin-na-universalni-poslugi?id=35077
[129] https://zakon.rada.gov.ua/laws/show/483-2019-%D0%BF#Text
[130] https://zakon.rada.gov.ua/laws/show/859-2021-%D0%BF#Text

	Barrier	Is it a barrier?	Please provide details
Network services and operations	Insufficient interconnector capacity not allowing to optimise flexibility use at supra-national level	Partially	At 11%, the interconnectivity level is low compared to other Energy Community Contracting Parties, and is lower if only interconnections to ENTSO-E members are considered (ECS, 2021, Electricity Interconnection Targets in the Energy Community Contracting Parties). With the full synchronisation to the ENTSO-E network however it should increase (see Generation Adequacy report).
	Existing interconnector capacity is not (sufficiently) made available to the market	Partially	Before Russia's invasion of Ukraine, market players in the BEI could access cross-border capacities to/from Hungary, Slovakia and Romania, with BEI being a net exporter. However, total export available transfer capacity was capped at 650 MW, leading to a reduction of the cross-border capacity (unilaterally) auctioned in an yearly, monthly and daily basis (Le Trading, 2021, Barriers and Constraints in the Electricity Market in Ukraine). Consequently, the availability of interconnectors is relatively low, with net transfer capacities (for all of Ukraine) amounting to only 34-37% of the nominal transmission capacity (ECS, 2021, Electricity Interconnection Targets in the Energy Community Contracting Parties). Joint capacity auctions with neighboring TSOs are now possible with a change in the legislation in 2021 (ECS, 2021, Cross-border Trading in Ukraine - Roundtable on Electricity Supply and Trade in the New Market Model) With the recent synchronization of Ukraine's power system with continental Europe, the country is virtually interconnected with most of Europe via ENTSO-E (of which UA is now an Observer Member too), thus availability of interconnectors as well as transmission capacity is expected to increase.
	Other network capacity, capacity allocation and congestion management issues	Partially	Electricity networks are in need of significant modernisation (Energy Security Strategy of Ukraine, 2021) Moderate to weak progress was observed with regards to generation capacity and network modernisation, since the process requires large investments that cannot be attracted by the TSO and DSOs until the introduction of the RAB tariff. (OECD, 2020, Monitoring the Energy Strategy of Ukraine 2035). Incentive regulation for most of DSO was introduced from 2021. Investments by TSO are made according to the Ten-year Development plan, approved by the Regulator, and investments programme.
	Inadequate network tariff design	Yes	Time-of-use network tariffs not in place.
	Lack of smart metering for low voltage-connected users	Partially	The residential smart meter penetration was 9.9% from total number of meters.[131]
	Lack of incentives for network operators to consider flexibility as alternative for investment in grid capacity	Yes	No incentives available
Taxes and subsidies	Inadequate / high taxation of flexibility sources (e.g. taxes on self-consumption, double taxation on storage)	-	NA
	Subsidisation of fossil-based / other power generation	Yes	751.52 million EUR or 8.99 EUR/MWh of direct subsidies provided to coal/lignite electricity producers in 2018/2019 (ECS, 2020, Investments into the past - An analysis of Direct Subsidies to Coal and Lignite Electricity Production in the Energy Community Contracting Parties 2018-2019) Subsidisation of coal mines and power plants continues (Energy Security Strategy of Ukraine, 2021)

131 NEURC Annual Report for 2020 (https://www.nerc.gov.ua/storage/app/sites/1/Docs/Richny_zvity/Richnyi_zvit_NKREKP_2020.pdf)

	Barrier	Is it a barrier?	Please provide details
	Market distortions due to support schemes	Partially	A successful feed-in tariff has led to a significant increase in renewable energy capacities, increasing system balancing needs but which was not accompanied by an increase of flexible capacity (Energy Security Strategy of Ukraine, 2021) In 2021 the government agreed with renewable energy producers for partial compensation of the feed-in tariff in case of curtailment. However, renewable energy producers have a number of complaints regarding the compensation and curtailment (WilmerHale, 2021). The guaranteed buyer is responsible for balancing imbalances of renewable energy producers, who must compensate it. The government has proposed a law for renewable energy producers to exit the balancing group of the guaranteed buyer (CMS Law, 2021). Starting from 2021 RES producers in the GB balancing group started to be partially responsible for their imbalances (with the incremental portion for the next years). Lack of competitive operation of RES producers on the market stipulated some distortions.
Technology-specific barriers	Other barriers to demand response	Yes	Several challenges identified (for demand-side management more broadly): - Regulated prices for households set below production costs and cross-subsidies - Lack of access to accurate, timely and comprehensive data for consumers (though TSO is finalizing the introduction of Data hub. - Infrastructure fragility reduces service reliability and bottlenecks restrict service access; incomplete smart metering and end-user control weakens potential demand responsiveness - Nature of existing infrastructure may limit the deployment of innovative technologies to improve demand restraint. - Access to affordable financing is constrained (IEA, 2021, Harnessing Energy Demand Restraint in Ukraine: A Roadmap)
	Other barriers to Gas-fired generation	No	Calculations based on current market prices indicate that, in most scenarios, investment in Combined Cycle Gas Turbine (CCGT) power plants would be profitable (Supponen, 2021, Reforming Ukraine's electricity market)
	Other barriers to EV smart charging / vehicle-to-grid	Partially	Some e-mobility issues defined in legislation. State support scheme for purchasing electric vehicles or construction of recharging infrastructure available: tax advantages for EV owners are in use and a traffic related subsidy i.e. free parking, was introduced (ECRB, 2021, E-mobility in the Energy Community Contracting Parties - Survey on the legal and regulatory framework and role of regulators)
	Other barriers to Storage (front / behind-the-meter)	No	The Law defining energy storage systems and operators, as well as several other aspects of the regulatory framework concerning storage according to the Directive 2019/944 was adopted by the Verkhovna Rada of Ukraine in February 2022. The Law gives a number of incentives for storages in respect of licensing and network tariffs application.
	Barriers to other technologies / existing power plants	Yes	There are no economic mechanisms (e.g. market-based) for the plant upgrade of old coal-based power plants to the new requirements of the Industrial Emissions Directive (DEA, 2019, Long-term Energy Modelling and Forecasting in Ukraine: Scenarios for the Action Plan of Energy Strategy of Ukraine until 2035). There is a mechanism of tenders for new generation capacity but it hasn't been used so far. In 2021 also a new Law on biogas was adopted with the aim to incentivise biogeneration.

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