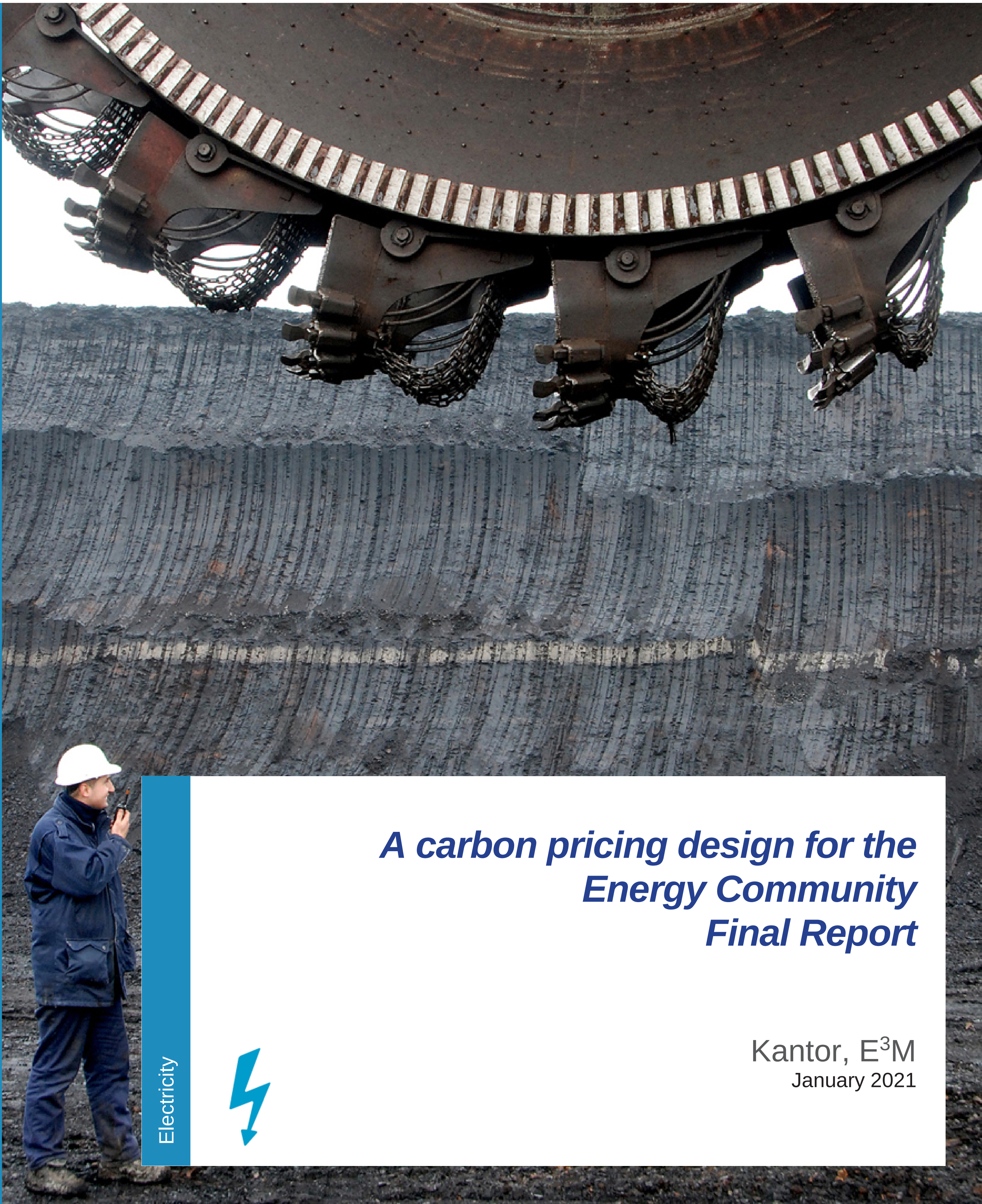
Energy Community



A carbon pricing design for the Energy Community Final Report

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Electricity

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A carbon pricing design for the Energy Community

Final Study Report

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Executive Summary

The Energy Community Secretariat has commissioned Kantor Management Consultants and E3 – Modelling to undertake the preparation of the study "A carbon pricing design for the Energy Community", hereinafter "EnC_Carbon". The aim of the study is to propose a carbon pricing mechanism for the time horizon until 2040, suitable for the decarbonisation of the power and district heating sectors in the Contracting Parties (CPs) of the Energy Community (EnC), considering the intrinsic political, economic and social context in these countries.

Carbon pricing has been a recurrent theme in the climate policy dialogue between the Energy Community and the European Union (EU), *for* carbon pricing has proven to play a key role in achieving meaningful greenhouse gas (GHG) emission reduction in the EU and in ensuring a level playing field, as energy markets become increasingly integrated. The need to come up with a carbon pricing mechanism for the Energy Community turns out to be pressing for three most obvious reasons. First, almost half of all electricity produced in the CPs still comes from old and inefficient thermal power plants burning solid fossil fuels, i.e. lignite and coal, despite mounting costs, generation adequacy concerns, air quality deterioration and public health effects. Second, solids-firing generation remains artificially cheap due to distortionary policies that conceal the true cost of carbon and hamper competition and the transition to a low-carbon power market. Third, solids-based electricity from the CPs is leaking into the EU, undermining Europe's climate policy and incentivising further the use of solids, i.e. coal and lignite, in the Energy Community.

With the European Green Deal unfolding, it becomes clear that Europe's transition to climate neutrality can only be effective if the block's immediate neighbourhood also takes meaningful climate action. This is echoed in the political cooperation frameworks that each CP maintains with the EU. For the Western Balkans in particular, the Green Deal foresees an Investment Plan and a Green Agenda, endorsed by Western Balkan leaders at the Sofia summit on November 10, 2020. Among other things, leaders commit to continue alignment with the EU Emissions Trading Scheme and work towards introducing other carbon pricing instruments to promote decarbonisation in the region. They also commit to develop and implement air quality strategies, increase the uptake of Best Available Techniques in accordance with the Industrial Emissions Directive, provide the necessary investment conditions for lifting the share of renewable energy sources (RES), phase out coal subsidies, and, most notably, work with the EU towards the 2050 target of a carbon-neutral continent.

After conducting an in-depth analysis of different carbon pricing schemes, the study identified Cap and Trade to be the first best policy option for introducing carbon pricing in the power and district heating sectors of the CPs. Also, the study invites the CPs to consider adjusting excise taxes on fuels to the EU average. The proposed tax would be high enough that, if combined with the existing excise taxes, it would close the gap with average tax levels in the three (3) EU Member States (EU MS) covered by the study, i.e.

Greece, Bulgaria and Romania. These countries are studied because of their linkages and extensive electricity trade with the CPs. Subsequently, the PRIMES-IEM model was used to quantify five (5) stylized scenarios for the introduction of carbon pricing in the power and district heating sectors in each CP. A set of assumptions validated by the EnC Secretariat and national contact points was used as input to the model, delivering projections for the evolution of the power generation mix, investment, prices, costs and CO2 emissions in the CPs and the three (3) EU MS.

Out of the five (5) scenarios, the ***Baseline Scenario*** foresees no carbon pricing but the continuation of current, asymmetric policies, where the EU MS abide by the rules of the EU Emissions Trading Scheme (EU ETS) while CPs don't, and power and gas markets remain fragmented. Model-based projections reveal that the Baseline scenario is not a sustainable policy option for the Energy Community. Without carbon pricing, solids persist in power and district heating, while access to cheaper, more secure and flexible gas is compromised, and RES develop poorly. Power generation continues to depend on an aged, inefficient, and polluting fleet. Uncertainties surrounding the continuation of operation breed reluctance to invest in refurbishing the solids-based fleet, which in turn raises concerns over adequacy of supply. Put together, these conditions question the competitiveness and reliability of solids-firing generation in the long-term in the Energy Community and are at odds with the EU policy ambition and expectations for a swift low-carbon transition in the CPs.

The analysis shows that the ***Baseline Scenario with a Cross-Border Adjustment Carbon Tax*** is not a sustainable policy option either. This variant of the Baseline, which assumes the imposition of a cross-border adjustment carbon tax (CBAT) on electricity exports from CPs to EU countries in proportion to their carbon intensity, is an inferior policy option and should not be considered. Projections reveal that such a carbon tax not only increases costs for consumers but also fails to eliminate solids from power generation and drive a sharp reduction in CO2 emissions in the CPs. This is because the tax applies on the entire power mix, and not just on solids, and so the impact on gas and RES is expected to be stronger, since the tax affects resources that are high in the merit order.

For the introduction of carbon pricing, four (4) alternative scenarios were considered, reflecting different combinations of a full *vs.* gradual application of carbon pricing within a context of integrated *vs.* fragmented power and gas markets. Carbon pricing is important to ensure that externalities in relation to climate impacts are paid and that the right signals are given to investors and users. More importantly and rather urgently, in the case of the Energy Community, it is to deliver an alternative to a carbon border tax, in order to avoid market fragmentation which would bring significant welfare loss. More so, carbon pricing is an important macroeconomic measure to partly alleviate the external impacts of carbon pricing, such as loss of jobs and potential increase in retail prices. Two assumptions were used regarding the pace and timing of carbon pricing: *full carbon pricing*, which foresees 100% auctioning of allowances from 2025 onwards in all CPs without exemptions, and *gradual carbon pricing*, where auctioning of allowances starts at 2025 but applies gradually, at different rates and speeds in each country. Despite the considerable pressure on the power system and the economy, carbon pricing is projected to bring CO2 emissions down significantly and provide a signal to investors that CPs are willing to transition away from solids. Carbon pricing is also set to offer a source of public revenues that can be recycled in the economy to alleviate costs, enable technological progress and fund investment in clean technologies. According to the analysis, the best recycling option on average is boosting the competitiveness of export-oriented firms, while the options of lowering labour costs and supporting household income come next. Moreover, notwithstanding the jobs that will be lost due to the decommissioning of thermal power plants, carbon pricing is projected to have a positive impact on the economy and employment as a whole. Pouring investments into RES deployment will create short-term and permanent jobs in the construction, equipment and services sectors that will compensate for the ones lost as a result of pulling investments from solids.

That said, the study argues that what defines the ability of CPs to tap the potential of carbon pricing in full, while shielding the socio-economic fabric against its unfavourable effects, is the way power and gas markets are set up and operate; in other words, whether power and gas markets integrate or remain fragmented. The analysis projects that under a ***Full Carbon Pricing and Market Fragmentation Scenario***, consumers will be subject to abrupt price increases, mainly as a result of market fragmentation and the consequential loss in welfare. This is because market fragmentation, where Net Transfer Capacities (NTCs) remain low, markets are not coupled and cross-border sharing of balancing and reserves does not take place, forces the CPs to maintain heavy emitters in operation for system purposes, in the absence of access to carbon-free resources and their balancing facilities. This severely undermines the development of variable RES. Likewise, a fragmented market means new gas investment remains untapped. As such, supply conditions remain unfavourable and access to cheaper, secure and more flexible gas that can substitute for coal and provide balancing for variable RES, is hampered. These conditions force the CPs to rely on domestic sources only, depriving them of the ability to adjust their power generation mix to a high carbon emissions price. For this reason, the transition is very costly and hard to manage from all angles – political, social and economic. Similar are the projections, though slightly less harsh, of a ***Gradual Carbon Pricing and Market Fragmentation Scenario*.**

Conversely, a ***Full Carbon Pricing and Market Integration*** scenario makes coal phase-out a reality by 2030 or just after. The severity of implications on costs and prices from full carbon pricing is quite high, but lessens thanks to market integration. The reason is that market integration boosts cross-border flow possibilities, allowing countries to access low-carbon and low-cost energy generation, reserve and balancing resources, and so diversify their power mix, increase system resilience, attract restructuring investment and adjust their system to the introduction of carbon pricing. This is particularly relevant for countries with acute carbon pricing risk exposure. What's more, a broad regional market improves gas supply conditions, allowing investors to anticipate capital returns of new gas investment. Gas thus emerges as a bridge fuel, playing an important role for balancing, integration of variable RES and electricity trade.

Notwithstanding the critical role of market integration, the full auctioning of allowances from 2025 will be particularly difficult to manage for most CPs. Projections indicate that combining market integration with gradual carbon pricing is enough to enable coal phase-out in a reasonable timeframe, and more so, in countries where it is most difficult to do. With this in mind, and acknowledging that the point of departure for all CPs is not the same due to variable degrees of vulnerability to carbon pricing, the study recommends the ***Gradual Carbon Pricing and Market Integration Scenario*** as the best policy option for the Energy Community. This entails that all CPs adopt carbon pricing in a coordinated way the earliest possible, but under a transitional regime, where different rates and timeframes for auctioning allowances apply. This is to accommodate the different levels of flexibility to carbon pricing and present the opportunity for a relatively smooth transition, where emitters can adapt more easily and consumers may avoid bearing strikingly high electricity and heat prices.

1 Introduction

The objective of the EnC_Carbon study is to propose the design of an effective carbon pricing mechanism conducive to the decarbonisation of the electricity and district-heating sectors in the CPs in a cost-effective and socially acceptable way.

The study is undertaken amidst landmark policy developments in the EU. The European Green Deal, the flagship growth strategy meant to take the block to climate neutrality by mid-century, is moving forward to an increase of the EU 2030 GHG emission reduction target to 55%, from at least 40% today, and make it legally binding for EU MS. To deliver on the additional emissions reduction, the upwards revision of key energy and climate targets will be required, a matter the European Commission (EC) will be looking at in 2021. Carbon pricing, a cornerstone of Europe's energy transition so far, will continue to play a central role. Increasing the stringency of the Market Stability Reserve (MSR) and extending the EU ETS to new sectors, i.e. buildings and transport, are on the table. Moreover, the EC is currently evaluating the introduction of a Carbon Border Adjustment Mechanism (CBAM), which would place a price on imports of certain goods from outside of the EU, in order to push EU partners to raise their climate ambition and reduce the risk of carbon leakage. Different options are being considered, and carbon tax is one of them. The modelling in this study (variant of the Baseline scenario) looks at the carbon tax option.

Inevitably, these developments will affect the EnC acquis. The incorporation into the acquis of the *amended* Directives on Renewable Energy, Energy Efficiency, and Electricity Market Design as well as the *new* Governance and Electricity Regulations, all part of the "Clean Energy for All Europeans" package adopted by EU MS in 2019, is coming up. Moreover, transposing the EU ETS Directive is a precondition for the Western Balkan CPs to move forward with their EU accession process, while the bilateral Association Agreements of Ukraine, Moldova, and Georgia with the EU include steps to this direction. The Green Agenda for the Western Balkans, part of the Green Deal, lays out ways to facilitate the swift alignment of the Western Balkan countries with the EU's Climate Law and to introduce carbon-pricing instruments to promote decarbonisation in the region. In this context, emissions trading is presented as an option to be explored. Moreover, fighting air pollution, accelerating decarbonisation through the uptake of RES and energy efficiency as well as circular economy, represent core pillars of the agenda.

At present, most of the CPs do not have any kind of carbon pricing scheme in place, except for Albania, where a carbon tax has been in place since 2008; Ukraine, which introduced a nominal tax in 2011; and Montenegro, where a national ETS covering the industry and power sectors is underway. Although power producers from the CPs increasingly participate in the single European electricity market supposedly on an equal footing with EU power producers, this is not actually the case, since the majority is not subject to any carbon-pricing scheme, carbon tax or ETS.

For the reasons stated above, it seems that the CPs will need to adopt carbon pricing sooner rather than later. An explicit price on GHG emissions and an end to coal subsidies will turn the old, polluting, and un-economic thermal power plant fleet of the EnC obsolete. In parallel, it will incite much needed restructuring investment in low and free-carbon alternative solutions that can ensure reduction of GHG emissions without compromising security of supply and affordability. What remains at stake is therefore not *whether* carbon pricing will apply in the EnC, but rather *at what pace* and under *which market conditions* in order to allow for an economical and socially tolerable implementation.

The report is structured as follows: first comes a summary of the macro-economic and energy outlook of the EnC region, highlighting the prevailing power and gas market trends (Chapter 2). The term EnC region is used to refer to the broader geographic area covered in the report, i.e. the CPs and the three EU MS, i.e. Greece, Bulgaria and Romania. Then follows an overview of carbon pricing schemes, lessons derived from international experience as well as current practices regarding carbon pricing in the CPs (Chapter 3). The policy option proposed for the EnC is presented next (Chapter 4), before laying out the methodology for building the scenarios and the key assumptions underpinning the modelling work (Chapter 5). A detailed impact assessment of the different scenarios on the electricity system and markets, the economy and employment is provided (Chapters 6, 7), along with the available options for recycling carbon pricing revenues (Chapter 8). The study concludes with a synopsis of key findings and recommendations (Chapter 9). The Appendix offers additional information on the model, the methodology for calculating electricity/heat pricing and for sourcing data, and the state of excise taxes in the CPs at present.

2 Policy context in the Energy Community

2.1 Economic and demographic outlook

The economies of the CPs are projected to grow steadily in the current decade and less so between 2030 and 2040 (Table 1). The average annual rate of growth of GDP in volume over the decade 2020-2030 is projected to range between 1.3% and 4%, while for the years 2030-2040, the range is between 1.9% and 3.4%. Consumption continues to be a key driver of economic activity, fuelled by higher public spending and near double-digit growth in household lending. In the Western Balkan countries in particular (Albania, Bosnia and Herzegovina, Kosovo*[1], Montenegro, North Macedonia, Serbia), services are driving growth, primarily retail and wholesale trade, tourism, information, and communication technology. The Ukrainian, Georgian, and Moldovan economies rest mainly on industry and agriculture. Overall, assumptions point to a positive and steady

[1] Throughout this report, this designation is without prejudice to positions on status and in line with the United Nations Security Council Resolution 1244 (1999).

growth for the region as a whole, albeit at somewhat decelerating rates during the next decade. NB: Assumptions about macro-economic trends do not take into consideration the COVID-19 crisis.

TABLE 1: GDP GROWTH RATES IN THE ENC REGION

	GDP (mill. € '2018)		Average annual rate of change	
	2019	2010-2020	2020-2030	2030-2040
ALBANIA	13,115	2.64	3.26	2.91
BOSNIA & HERZEGOVINA	17,279	2.25	3.51	3.01
BULGARIA	58,106	2.58	2.92	2.62
GREECE	188,334	-1.21	2.03	1.90
KOSOVO*	6,995	3.62	3.76	3.41
MONTENEGRO	4,803	2.79	2.98	2.73
NORTH MACEDONIA	11,030	2.52	3.08	2.92
ROMANIA	212,622	3.84	2.75	2.34
SERBIA	44,650	2.21	3.52	2.92
GEORGIA	11,360	3.52	4.01	3.41
MOLDOVA	10,469	4.35	3.55	3.22
UKRAINE	113,520	0.14	2.97	3.02

Predictions about demographic development in the region are bleak, a result of declining fertility rates and significant outgoing migration fuelled mainly by high unemployment across labour markets. Almost all CPs will experience population decline until 2040, with the exception of North Macedonia and Montenegro (Table 2).

TABLE 2: POPULATION AND GDP PER CAPITA IN THE ENC REGION

	Population (mill.)	Annual rate of change	GDP per person (€'2018)		
	2019	2019-2040	2019	2030	2040
ALBANIA	2.86	(0.10)	4,582	6,604	8,887
BOSNIA & HERZEGOVINA	3.50	(0.29)	5,234	7,900	10,920
BULGARIA	7.00	(0.14)	8,301	11,616	15,208
GREECE	10.72	(0.43)	17,561	23,143	29,189
KOSOVO*	1.86	(0.09)	3,746	5,714	8,067
MONTENEGRO	0.62	0.10	7,720	10,570	13,694
NORTH MACEDONIA	2.08	0.07	5,310	7,362	9,744
ROMANIA	19.41	(0.40)	10,952	15,542	20,363
SERBIA	6.96	(0.41)	6,412	9,861	13,690
GEORGIA	3.72	(0.08)	3,051	4,724	6,699

MOLDOVA	3.54	(0.10)	2,955	4,390	6,089
UKRAINE	41.98	(0.51)	2,704	3,938	5,579

Increase in energy demand has gone hand in hand with a growing economy. Countries in the region have been implementing reforms to improve their competitiveness, which significantly contributed to economic growth from the early 2000s. Nevertheless, the 2008 financial crisis hit the region hard: GDP fell in 2009 and growth remained sluggish for years, only to recover from 2015 onwards. This led to a significant decline in energy demand in all sectors over slackening production and a drop in useful energy services[2]. More so, the transition to a market economy in the past two decades has had important effects on the sectoral composition of energy demand in the region. Economic growth is now underpinned mainly by services and to a lesser degree by construction. Hence, energy consumption is shifting away from energy-intensive industries towards the services and residential sectors.

The principal energy-intensive industries, i.e. steel, cement, petrochemicals, mining- and resource-based industries are assumed to continue in the future but grow very modestly compared to GDP. The gradual shift towards products with high added value, notably for equipment goods, food, and low-energy intensive chemicals, will imply production volume to increase in the future at a pace slightly slower than GDP growth. The improvement of energy productivity embedded in new investment in high-quality and specialised products, as well as in energy efficiency investment, mainly heat recovery and control systems, supports the improvement of energy efficiency and the increase in value-added; so production volumes increase less than the value-added. Thus, specific energy consumption reduces**.** At the same time, electricity shares in industry increase, while heat and steam uses tend to rely more on gas, where gas supply exists, rather than fuel oil or solids.

Moreover, improved energy efficiency has an impact on agriculture, which is assumed to follow a modest pace of growth, as well as buildings and transport. In fact, energy efficiency is increasingly seen as a key pillar in national energy strategies, helping to enhance energy security, contribute to economic growth, and ensure environmental sustainability. The energy retrofit of old buildings is seen as the unexploited “golden goose” of energy savings potential. The renovation of old buildings is progressing, though at a slow pace, remaining slightly above historical rates, which are modest and involve shallow refurbishment. Furthermore, the growth rate of new constructions that are energy efficient is small, despite the adoption of building codes imposing energy efficiency standards.

[2] Useful energy services refer to the provision of the desirable amounts of energy to cover sufficiently the need for heating, cooling, and electricity.

At the same time, electrification is projected to dominate heat uses, driven mainly by heat pumps. Heat pumps are also a preferred solution in the services sector due to economies of scale, the combination of heating with cooling and air ventilation, and the relatively low rate of utilisation of the buildings. Where gas supply exists, higher use of gas replacing other fossil fuels in heating is observed. However, useful energy demand for heating and cooling increases, since there is still room for improvement of comfort level in the sector, while the rise in income per capita allows for the expansion of the appliances stock. Therefore, despite energy efficiency improvements driven by technological progress and the adoption of eco-design regulations, electricity consumption for appliances and lighting continues to increase.

Last, the transport sector has yet to reach geographical and market saturation and tends to increase faster than GDP, both for passengers and for freight. This concerns mainly aviation, cars and trucks, where activity increases faster than in other modes. Rail on the other hand is experiencing a declining trend, a result of the shift towards a more service-oriented economic model in the region. However, rail-support policies succeed to slowdown this trend. The efficiency of vehicles improves, driven by vehicle standards, but the high share of imported second hand vehicles reduces potential improvement. Similarly, the electrification of transport is expected to emerge but at a slower pace than in large EU countries.

2.2 Capacity mix and trends in power and gas markets

Historically, CPs have used solid fossil fuels complemented by hydro and nuclear to produce electricity. The diversification of the energy supply mix is limited with solids accounting for approximately 50 % of the primary energy production (Table 4). Solids-based generation accounts for the lion's share of electricity generation, yet the electricity mix varies considerably among countries, with Albania relying entirely on hydro generation and Kosovo* depending almost entirely on lignite. Other countries have a combination of both thermal and hydro generation.

The conscious move to favour lignite as a primary energy fuel in national energy strategies is due to the low costs of lignite compared to other energy sources (Table 3). Cheap, domestically available lignite has sustained electrification by ensuring affordable and stable prices of electricity. However, a large part of the power plant fleet is aged, as exploitation has often exceeded standard power plant lifetimes. In addition, the majority of those plants do not comply with the air pollution standards set in the *Large Combustion Plant* Directive.

Dis-economies of scale due to the increasing costs of mining exploitation and to the decrease in the rate of use of the mining capacities have pushed lignite costs significantly upwards (with few exceptions). Technical and market conditions point to a decrease in the use rate of solids-based generation, which implies low operation of lignite mines, pushing costs upwards, since these are predominantly fixed and inelastic.

TABLE 3: RANGE OF LIGNITE OR COAL MINING COSTS IN 2018 (€/MWH)

€/MWh-fuel	Low	High
ALBANIA	NA	NA
BOSNIA & HERZEGOVINA	7.1	9.5
BULGARIA	4.8	6.3
KOSOVO*	11.9	12.1
NORTH MACEDONIA	8.6	9
MONTENEGRO	11.3	11.6
SERBIA	7.5	10.2
GREECE	9.8	13.6
ROMANIA	7.7	9.4
UKRAINE (coal)	9.2	9.4
MOLDOVA (coal)	9.2	9.4
GEORGIA	NA	NA

Even though growth rates of energy demand are moderate, the deteriorated stock of infrastructure means that important efforts will be required to meet the projected electricity needs of the region, while ensuring adequate reserve margins and reliability. Nevertheless, there is reluctance to undertake such investment because of uncertainties surrounding return on investment and the continuation of lignite fleet operation in the future. As a result, investment prospects lag behind electricity demand requirements and old power plants may be likely to remain in operation while exporting capacities erode. These conditions call the competitiveness and reliability of solids-firing generation in the medium-to long-term in most CPs into question.

TABLE 4: POWER GENERATION CAPACITIES IN 2018 (MW)

COUNTRY	LIGNITE	COAL	GAS/OIL	NUCLEAR	RES (excl. hydro)	HYDRO (incl. pumped storage)
ALBANIA	0	0	0	0	0	1990
BOSNIA & HERZEGOVINA	1888	0	50	0	79	2131
BULGARIA	3141	818	1085	1890	1767	3220
GREECE	3904	0	5212[3]	0	5194	3475
KOSOVO*	1147	0	0	0	41	95
MONTENEGRO	225	0	0	0	75	659
NORTH MACEDONIA	736	0	230	0	66	508
ROMANIA	3298	609	2742	1305	4329	6505

[3] Installed capacity of continental Greece (excl. GTs/in non-interconnected islands)

SERBIA	4021	0	345	0	390	3097
UKRAINE	-	15159	11864	13150	2175	6033
MOLDOVA	-	1600[4]	1385	-	45	64
GEORGIA	0	12	852	-	21	3197

Lignite competitiveness is diminishing also in the three EU MS considered in this study, owing to the 2018 reform of the MSR, which resulted in soaring EU ETS prices. Even though the granting of free allowances in Bulgaria and Romania has preserved lignite's rank in the merit-order until today, the expected application of the auctioning of allowances post-2020 will certainly put further strain on already stretched solids-firing thermal plants also in these two countries. According to their NECPs, both countries intend to apply carbon pricing to power generation from solid fuels fully, both in the domestic merit order and in cross-border trade. Moreover, the two countries have decided to implement Article 10c of the revised ETS Directive in phase 4 of the EU ETS (2021-2030) and safeguard a derogation for transitional free allocation in the power sector. The revenues they will receive in the form of transfer payments from other EU countries in the context of the ETS mechanism will be used to offset partly the pressure that carbon pricing will exert on electricity prices for consumers.

As far as gas is concerned, supply uncertainty hampers investment in new Combined Cycle Gas Turbine (CCGT) plants, which could replace old lignite plants and reduce carbon emissions. Domestic production of gas in the CPs is limited (with the exception of Serbia and Ukraine), and there exist no functioning gas markets in Albania, Kosovo* or Montenegro. In the Western Balkans specifically, poor gas supply infrastructure due to lack of interconnections and diverse entry points in the regional gas system, in tandem with policies that provide direct or indirect support to lignite and coal in power generation, has made gas pricing and supply uncertain and has discouraged gas power plant investment at a large scale. Regarding hydropower, currently few large-scale investments are ongoing in the region. Large hydropower potential in most CPs is tapped already. For small hydro projects, the economic feasibility can be brought into question, especially taking the environmental impacts they may cause into account. Nuclear capacity development concerns Bulgaria, Romania and Ukraine. The plans are for the three countries to maintain nuclear capacities, and for Romania to expand after 2030. However, financing is a challenge for this prospect.

Lastly, public policies facilitating investment in RES and variable RES in particular develop unequally in the region. EU MS abide by the targets in the RES Directive, projected to be revised upwards in 2021, while CPs have made commitments to binding EU-mandated energy and climate targets by 2020 in the context of implementing the EnC acquis on renewable energy. However, hydro and traditional biomass resources still play a major

[4] Used only for reserves

role and ambitious support policies for variable RES have not been put in place, resulting in poor variable RES deployment. At present, CPs are drafting integrated National Energy and Climate Plans (NECPs), meant to streamline multiple monitoring and reporting obligations on climate and energy, reduce the administrative burden and enhance transparency for all energy actors, while promoting investor certainty. NECPs are meant to support CPs in reaching 2030 energy and climate targets which will be set for the EnC as a whole and need to be ambitious enough to bridge the gap with EU target levels.

In Eastern countries, the situation regarding the capacity mix is summarized below. Moldova covers all its energy needs, including electricity, oil, and gas, via imports and this is not expected to change in the near future. In Ukraine, coal resources are rather abundant but the coal fleet is inefficient and a plan for coal plant refurbishment is underway. While gas currently holds almost an equal share with coal and electricity in the energy mix, development of gas is not envisaged to be significant. Nuclear will continue to play an important role, covering a large part of electricity demand, yet investment in expansion is not secured. RES potential is noteworthy, though still largely untapped, something that is planned to change. Energy prices in the country are still largely regulated and heavy subsidies persist. This concerns direct subsidies and debt pay-offs to state-owned coal mines. Georgia, with insignificant coal reserves, has been carrying out an aggressive gasification programme, reflected in significant investment for the expansion of the gas distribution network. A key enabling factor is that natural gas prices are below market cost thanks to the country's transit role in the Caucus region, with major oil and gas pipelines running across its territory.

By and large, power and gas markets in the EnC are characterised by lack of liquidity. Inadequate or non-existing gas infrastructure, restricting the potential for supply diversification, along with anti-competitive clauses, long-term commitments to supply, and cross-border capacity and storage reservations are all reasons for the unfavourable gas supply conditions. These shortcomings are magnified by the absence of a legal level playing field between CPs and EU MS. Third party access rules, including congestion management mechanisms and entry-exit tariff methodologies, are still not fully implemented in the CPs. In addition, rules on balancing of transmission networks are hardly implemented at all, even where such laws exist.

Power market competition is also limited with state-owned production and supply companies still holding a dominant position, receiving subsidies and other forms of state support. Day-ahead markets are established to some extent; intra-day markets on the other hand are not established at all. An appropriate legal framework to enable the development of Demand Side Response and the provision of ancillary services is not really present or enforced. Balancing markets are to a high degree regulated, with almost no provision of regional capacity allocation. This poses a barrier to cross-border balancing, resulting in quasi-isolated national balancing markets with high dominance of incumbents and poor regional market cooperation. Still today, a large portion of customers enjoys electricity at regulated prices, despite certain de-regulation provisions applying in different CPs.

Finally, subsidies to coal-based power generation remain widespread in the region, representing a key barrier to the development of integrated electricity markets. This is also the key finding of the latest EnC report[5] on the matter (December, 2020). Incumbent generators are compensated through channels other than through the sale of electricity, which is a disincentive to invest in generation capacity. Directed towards state-owned utilities, subsidies take many forms. They can be direct, given out as fiscal support (debt write-off, tax concessions, state loans and direct budget transfers), public finance support (state guarantees for the construction of new coal-fired thermal plants) and enterprise investment support (pass-through costs in regulated tariffs or shareholder contribution for investment). They can also be indirect, allowing the operation of aging coal-fired thermal power plants at a low or negative level of profitability. Such subsidies, recorded across the majority of CPs, conceal the true cost of carbon-based electricity production and prevent the existence of a level playing field that ensures market competition and liquidity.

The current state of affairs presents a challenge for the energy transition in the EnC. The purpose of the study is to show how pricing carbon can change that. The following section gives a brief synopsis of different types of carbon pricing, the experience from Europe and the world and the state of play in the EnC at present.

3 Putting a price on carbon: key considerations

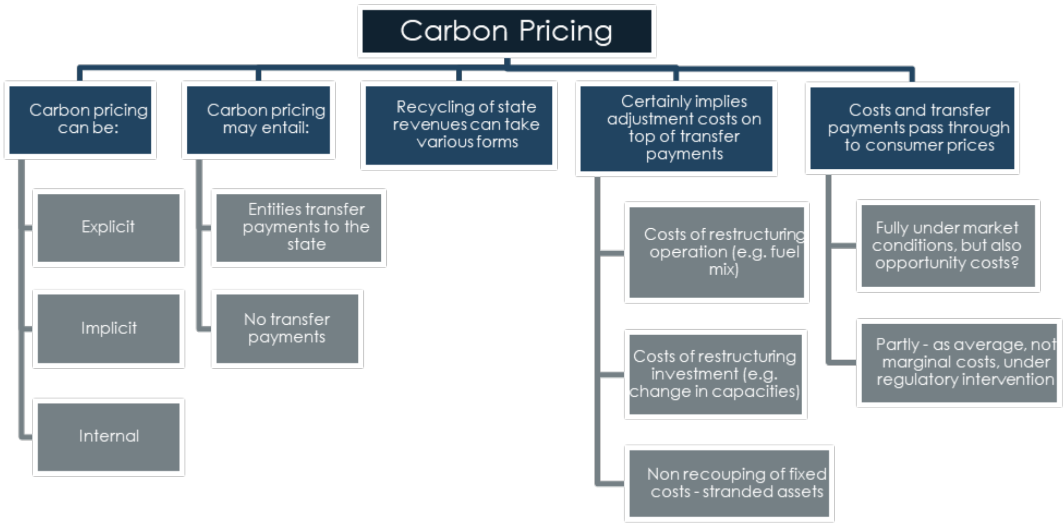
3.1 Overview of carbon pricing schemes

Carbon pricing refers to a measure that puts an explicit price on GHG emissions, i.e. a price expressed as a value per ton of carbon dioxide equivalent (€/tCO2). This way carbon pricing captures the external costs of GHG emissions, creating an incentive for emitters to adjust operation and investment to the price structure modified by the carbon price. As shown in Figure 1, carbon pricing can take various forms. It can be explicit or implicit, entail transfer payments to the state or not, be practiced at company level only or across sectors, be state-regulated or market-based.

Certainly, carbon pricing implies adjustment costs for an installation, namely costs associated with the restructuring of operation, investment and non-recouping of fixed costs because of reduced operation, the so-called stranded assets. The economic impacts of carbon pricing essentially depend on marginal abatement costs, i.e. the price-elasticity of the emitter. Overall, consumers are better off when abatement is low-cost. Carbon pricing definitely entails some kind of scheme for recycling collected revenues. The following sections offer an overview of different carbon pricing schemes and present the policy option that was retained by the study as most suitable for the CPs.

[5] https://www.energy-community.org/news/Energy-Community-News/2020/12/02.html

FIGURE 1: DIFFERENT FORMS OF CARBON PRICING



Internal carbon pricing reflects the consideration – internally by an entity – of a carbon price in all decisions for operation and investment. Internal carbon pricing can be *Explicit* or *Implicit*. In the first case, carbon pricing is set as a price administratively and affects all economic calculations and supporting decisions whereas in the second case an upper bound on emissions applies for on-going operations and future investment. As such, internal carbon pricing may be mandatory by regulation or enforced via emission credits – or certificates. Transfer payments to the state do not take place, but the company carries additional costs in operation and investment, which may eventually affect consumer prices. Under internal carbon pricing, emitters internalize the carbon price even if they do not pay for the allowance. Internal carbon pricing is in fact a way of "training" for emitters, which is the reason why it is not sustained but represents the first stage of introducing carbon pricing in a jurisdiction.

Explicit carbon pricing applies in two different ways: as an environmental tax or a carbon tax. Explicit carbon pricing entails transfer payments to the state, thus a financial burden on the consumer, as well as additional costs of adjustment for the emitting company. An *environmental tax* is a tax whose tax base is a physical unit (or a proxy of it) of something, that has a proven, negative impact on the environment. Thus, the company running the installation bears the tax proportionally to the GHG it emits. The focus is not on the fuel origin of the emissions. On the other hand, a *carbon tax* applies on the purchasing of a GHG emitting product, e.g. a fuel, in which case the buyer of the product bears the carbon pricing. In that sense, a carbon tax does not differ from an excise tax, except the way it is numerically calculated. A carbon tax is proportional to GHG emissions (€/tCO2), whereas an excise tax is proportional to the volume or energy content of the product (€/lit).

Implicit carbon pricing can apply as the price of a GHG emission allowance certificate, which is the case of the EU ETS. A central authority issues the allowances, serving to justify GHG emissions. The emitting installation has to own the corresponding allowances to justify emissions otherwise a penalty applies. The number of allowances issued are fewer than actual emissions, and in this manner, emissions are capped. There are three approaches to acquiring allowances: *Free allowances,* where a central authority grants allowances to installations and so payments to the state do not occur. *Auctioned allowances*, where installations buy the allowances and so transfer payments to the state take place. Under this approach, the total number of allowances available is less than the total demand and two possibilities exist: *either* the installation pays for the allowances at a price set by the authority, and the authority defines the maximum number of allowances available per installation; *or* the authority organizes pay-as-clear auctions to allow installations to buy allowances. The number of allowances auctioned is less than expected emissions, and the prices of the allowances are thus market-based. Last, *a hybrid mechanism* may apply*,* where part of the allowances is free and part auctioned.

The system of allowances complements a set of pre-conditions, which ensure the liquidity, integrity and transparency of the market. Under the EU ETS, apart from the EU ETS legislation itself, a complex system of provisions applies, one that covers areas of financial, tax, criminal and property law. Pivotal to the effective operation of an allowance trading system is the existence of a level playing field in power trading. This entails scrapping of subsidies and other distortionary policies supporting emitters (in particular if they face carbon pricing) that perpetuate the under-costing electricity pricing. Furthermore, a sophisticated Monitoring, Reporting and Verification (MRV) system has to be in place to ensure a robust process of allocating allowances, which can in turn build trust on the side of emitting companies towards the scheme.

Principles

- *Tradability*: Participants that reduce their GHG emissions further than required can trade their excess allowances with other participants that have a shortage of allowances, independent of whether these allowances are free or payable. Trading can take place at national or international level, or between companies and may be allowed only to emitters or to all companies. No tradability implies a central buyer and seller.
- *Borrowing:* Refers to the act of borrowing allowances from future allocation for current use.
- *Banking:* Refers to the saving of unused allowances for future use. However, banking may be valid only within the year of issuance, and not in a future time.

Theoretically, the banking and borrowing mechanisms, when effective, may allow for inter-temporal flexibility and in turn help reduce overall compliance costs. Nonetheless, if not regulated, banking and borrowing can bring about excessive actual emissions and counteract the mere purpose of the allowances system.

Preconditions

Before implicit carbon pricing can be put in operation effectively, a number of legal pre-conditions ensuring the liquidity, integrity and transparency of the market need to be respected. Under the EU ETS, apart from the EU ETS legislation itself, provisions in the field of financial, tax, criminal and property law also apply and need to be respected. These are analytically described in the report *"Legal nature of EU ETS allowances"*[6] and summarized in Table 5:

TABLE 5: EU ETS ALLOWANCES LEGAL FRAMEWORK

Area of EU Law	Directives/Regulations
EU ETS legislation	• Directive 2003/87/EC (ETS Directive 2003/87/EC) **NB:** *Monitoring, Reporting, Verification and Accreditation requirements of the EU ETS are harmonized with the two relevant regulations; the MRR (Monitoring and Reporting Regulation) and the AVR (Accreditation and Verification Regulation)* • Commission Regulation (EU) 389/2013 (Registry Regulation 389/2013) • Commission Regulation (EU) 1031/2010 (Auctioning Regulation 1031/2010)
Financial Law	• Directive 2014/65/EU on markets in financial instruments (MiFID II) • Regulation (EU) 2015/848 of 20 May 2015 on insolvency proceedings (Regulation 2015/848) • Directive 2002/47/EC on financial collateral arrangements (Financial Collateral Directive 2002/47/EC, FCD) • Directive 98/26/EC on settlement finality in payment and securities settlement systems (Settlement Finality Directive 98/26/EC, SFD)
Tax Law	• Directive 2010/23/EU amending Directive 2006/112/EC (VAT Directive 2006/112/EC) • Council Directive (EU) 2018/1695 of 6 November 2018 amending Directive 2006/112/EC on the common system of value added tax as regards the period of application of the optional reverse-charge mechanism in relation to supplies of certain goods and services susceptible to fraud and of the Quick Reaction Mechanism against VAT fraud
Criminal Law	• Regulation (EU) No 596/2014 on market abuse (Market Abuse Regulation 596/2014) • Directive 2014/57/EU on criminal sanctions for market abuse (Market Abuse Directive 2014/57/EU) • Directive (EU) 2015/849 on the prevention of the use of the financial system for the purposes of money laundering or terrorist financing (Anti-Money Laundering Directive 2015/849/EU)
Property Law	• Article 345 Treaty of the Functioning of the European Union (TFEU)

3.2 Lessons derived from international experience

An overview of selected carbon pricing schemes from EU and non-EU countries is provided below. Emphasis is placed on key design features, including major constrains that have been identified in the implementation of these schemes.

TABLE 6: SELECTED CARBON PRICING PRACTICES INSIDE AND OUTSIDE EUROPE

[6] https://op.europa.eu/en/publication-detail/-/publication/9d985256-a6a9-11e9-9d01-01aa75ed71a1

Carbon Tax/ETS	Key features	Major constraints
EU ETS	- Declining allowance cap rates every year and a market stability reserve (MSR) to manage liquidity are two features that allowed to address over-allocation of phase 1 & 2 - Progressive increase of auctioning, generating about €14 billion between 2012 and 2016 https://ec.europa.eu/clima/policies/ets_en	- The persistent low price of allowances in spite of market intervention measures constitute major concern for the EU ETS system - This shortcoming was addressed through a stringent MSR, raising the annual reductions in allowances to 2.2% as of 2021 so as to reduce the surplus of emission allowances in the carbon market.
USA - California Cap and Trade Program	- Allowance price-containment reserve, which gives regulators the power to remove or add allowances into the market - Free allowances to energy-intensive and trade exposed (EITE) industries to reduce leakage, and rigorous monitoring of allowances, offsets, and emissions reductions - Covered entities steadily reduced emissions[7]	- Legal challenges and issues with carbon leakage due to resource reshuffling by electric utilities, which has threatened the integrity of the program[8] - Several complementary emission reduction policies lead to increased market uncertainty[9]
Canada - Québec Cap and Trade System	- Integrity of the program is ensured by the extremely stringent MRV and the severe consequences in terms of financial and criminal offences[10] - "Green Fund'' channels revenues in other emissions-reducing activities. 2013 estimates showed a 7.5% decrease from 2005 levels in emissions[11]	- Low emissions base results in a low amount of attractive opportunities to reduce emissions
Regional Greenhouse Gas Initiative (RGGI)	- Transparency and commitment to periodic program reviews to adjust its ETS market[12] - Full auctioning of allowances, significant revenue generation, and investment of revenue towards other emissions-reducing activities	- Scope and coverage. RGGI addresses only CO_2 emissions from electricity units over 25 megawatts of capacity - Excluding other GHGs and other sectors limits the scope and potential impact of the program on the region's emissions reduction[13]
Swiss Emissions Trading	- Switzerland's strategy to exempt enterprises from its carbon tax in exchange for participation in the voluntary ETS market	- Swiss ETS has not been shown to be more cost effective than its carbon tax[15]

[7] Source : https://icapcarbonaction.com/en/
[8] Source : https://www.tandfonline.com/doi/abs/10.1177/0096340214546834?journalCode=rbul20
[9] Source : https://ieta.wildapricot.org/resources/EU/Overlapping_Policies_Drafting_Group/epri_ complementary_mech_report_highlighted.pdf
[10] Source: https://icapcarbonaction.com/en/?option=com_attach&task=download&id=648
[11] Source: Canada's Second Biennial Report on Climate Change. Gatineau QC: Environment and Climate Change Canada, 2016.
[12] Source: https://www.eenews.net/climatewire/stories/1060056710/search?keyword=RGGI
[13] Source : https://www.sciencedirect.com/science/article/pii/S0140988315002273?via%3Dihub
[15] Source : https://sites.tufts.edu/cierp/files/2017/11/Carbon-Pricing-In-Practice-A-Review-of-the-Evidence.pdf

Carbon Tax/ETS	Key features	Major constraints
Scheme & Carbon Tax	is a notable feature in terms of garnering political acceptance towards a transition to a full ETS market[14] - Inclusion of the aviation sector to align with EU ETS rules was considered as a very good step for a future linking with the EU ETS	- Allocating 80% of allowances for free in the second compliance period and the low allowance prices in the market created few incentives for participants to reduce emissions[16]
British Columbia Carbon Tax	- Focus on equity and fairness raised acceptance of the scheme - The tax is designed to mitigate the distributional impacts, thus the incentive for households to reduce emissions is maintained[17]	- The carbon tax is still too low in terms of price to drive the shift to new low-carbon practices[18]
Chilean Carbon Tax	- Easier to be socially accepted, since the carbon tax increased taxes on big businesses, and it was recycled in a way that lowered the tax burden for consumers	- Research shows that with the current price of 5 USD, no industrial source will probably decide to opt for cleaner fuels[19]
French Carbon Tax	- Redistribution measures of the revenues raised from the carbon tax have positive effects on activity and employment, have helped reduce dependence on oil and have improved the trade balance[20] - The tax allows pricing carbon in businesses excluded due to their size from the EU ETS[21]	- In 2000 one of the main flaws of the tax was that it did not comprise a long-term evolution of the carbon price[22] - As a result of intense social negotiations and protests, the government included many exemptions for companies
Polish Carbon Tax	- n/a	- Extremely low price, has sent insignificant abatement signals to the industry
UK Price floor CO2	- Broad sector coverage including additional emitters not covered by the EU ETS	- Political risks. The design of the carbon price floor (CPF) – in which the Treasury sets the price floor three years ahead of delivery and via a vote on the Finance Bill – has been criticized for not providing investors with the long-term certainty needed to invest in low carbon energy[23] - Relatively imprecise in terms of securing investment compared to other policy options that have either been implemented or proposed[24]

[14] Source : https://sites.tufts.edu/cierp/files/2017/11/Carbon-Pricing-In-Practice-A-Review-of-the-Evidence.pdf
[16] Source : https://sites.tufts.edu/cierp/files/2017/11/Carbon-Pricing-In-Practice-A-Review-of-the-Evidence.pdf
[17] Source : https://institute.smartprosperity.ca/sites/default/files/publications/files/Read%20Submission%20here.pdf
[18] Source : https://institute.smartprosperity.ca/sites/default/files/publications/files/Read%20Submission%20here.pdf
[19] Source : https://larrlasa.org/articles/10.25222/larr.33/
[20] Source : https://www.ecologique-solidaire.gouv.fr/fiscalite-carbone
[21] Source : https://www.ecologique-solidaire.gouv.fr/fiscalite-carbone
[22] Source : https://www.iges.or.jp/en/publication_documents/pub/workingpaper/en/5983/The_Rise_of_Carbon_Taxation_in_France_Rocamora_May_2017.pdf
[23] Source: file:///C:/Users/santo/Downloads/SN05927.pdf
[24] Source: file:///C:/Users/santo/Downloads/SN05927.pdf

3.3 Existing carbon pricing and MRV mechanisms in the CPs

At present, most of the CPs do not have any kind of carbon pricing schemes in place. Only Albania has introduced a carbon tax since 2008, Ukraine, a nominal tax since 2011 and Montenegro, an excise tax on coal used for electricity generation in 2019. Power producers from the CPs increasingly participate in the single European electricity market, yet not on an equal footing, since they are not subject to any carbon-pricing scheme.

TABLE 7: CARBON PRICING SCHEMES IN THE ENC

Contracting Party	Type	Status	Comments
ALBANIA	Carbon Tax	established since 2008	n/a
	ETS	under consideration	Intention to use international carbon pricing (NDC)
BOSNIA & HERZEGOVINA	Carbon Tax	not implemented	n/a
	ETS	under consideration	Intention to use international carbon pricing (NDC)
GEORGIA	Carbon Tax	not implemented	n/a
	ETS	not implemented	n/a
KOSOVO*	Carbon Tax	not implemented	n/a
	ETS	not implemented	n/a
NORTH MACEDONIA	Carbon Tax	not implemented	n/a
	ETS	under consideration	Intention to use international carbon pricing (NDC)
MOLDOVA	Carbon Tax	not implemented	n/a
	ETS	under consideration	Intention to use bilateral, regional and international carbon pricing (NDC)
MONTENEGRO	Carbon Tax	not implemented	n/a
	ETS	under development	The “Law on Protection from the Negative Impacts of Climate Change” of 2019 and the new regulation on activities emitting GHG of 22.02.2020[25] define the basic elements for the implementation of the national ETS according to EU ETS standards
SERBIA	Carbon Tax	not implemented	n/a
	ETS	under development	Serbia is expected to adopt a legislative framework, transposing elements of the EU ETS system in the foreseeable future

[25] Date in which the regulation entered into force.

Contracting Party	Type	Status	Comments
UKRAINE	Carbon Tax	established since 2011	n/a
	ETS	under development	ETS in line with its obligations under the Ukraine-EU Association Agreement. Currently, development of the main elements of the national MRV system according to EU ETS standards

The CPs abide by monitoring and reporting commitments in areas like RES, energy efficiency and GHG emissions, as part of different energy and climate strategy and planning processes. All CPs except Kosovo* have ratified the United Nations Framework Convention on Climate Change (UNFCCC), the Kyoto Protocol and the Paris Agreement, and have submitted their Nationally Determined Contributions (NDCs). The NDCs include national GHG emission reduction targets for 2030, aimed at helping meet the long-term objectives of the Paris Agreement. The sectoral coverage of the targets focusses on the energy sector, mainly fuel combustion activities (power sector, industry, transport etc.).

Furthermore, in January 2018, the 15th Ministerial Council of the EnC adopted Recommendation 2018/01/MC-EnC, inviting the CPs to develop integrated NECPs for the period 2021-2030, meant to address the five dimensions of the Energy Union Strategy, aligned with requirements of the Governance Regulation (Regulation (EU) 2018/1999). The recommendation is supplemented by Policy Guidelines (PG 03/2018) that guide CPs in the elaboration of their NECPs, establishing thee distinct targets on RES development, energy efficiency uptake and GHG emission reduction. The targets will be set in 2021 and be ambitious enough to bridge the gap with EU target levels.

MRV is included in the national communications and updated reports submitted by the CPs in the framework of the UNFCCC mechanism. The majority of CPs, as non-Annex I Parties to the UNFCCC and its Kyoto Protocol, have no quantified commitments regarding MRV and are not obliged to report frequently. Only Ukraine is an Annex I Party and has to report to the UNFCCC annually on its GHG emissions (“national GHG inventories”) and regularly on its climate change policies & measures and progress towards meeting its national targets (“biennial reports” and “national communications”)[26].

Most CPs are now starting to put in place MRV systems, in line with the Monitoring Mechanism Regulation (No 525/2013), which from 2022 onwards will be replaced by the Governance Regulation (2018/1999) in the EU and in the EnC once the transposition of the Winter Package into the EnC acquis is completed. In Ukraine, the MRV Law entered into force in March 2020. However, secondary legislation is needed to move forward with the establishment of an integrated MRV mechanism. In 2019, Montenegro adopted a law aligning national legislation with the international treaties on climate change, which

[26] Source : https://ec.europa.eu/clima/policies/strategies/progress/monitoring_en

incorporates among others, MRV elements according to the EU ETS and the MMR. The upcoming Climate Change Law of Serbia is expected to transpose requirements of the EU ETS and MMR, while Albania and Moldova have both transposed the MMR Regulation. The rest of the CPs are at the stage of transposing the MMR Regulation.

TABLE 8: OVERVIEW OF THE NATIONAL POLICY & REGULATORY FRAMEWORKS FOR SETTING UP AND OPERATING MRV SCHEMES IN THE ENC

EnC CP	Overview of the status of the national MRV's policy and regulatory framework
ALBANIA	The "Law on Climate Change" adopted in 2019 establishes the institutional framework and arranges the rules for MRV of GHG emissions at the level of sectors/resources and at the national level in line with the MMR Regulation.
BOSNIA & HERZEGOVINA	Bosnia and Herzegovina does not have a clearly defined MRV system for GHG emission data. However, the rules on developing emission inventories are primarily stipulated by the air protection laws of the two entities [(Law on Air Protection "Official Gazette of Republic of Srpska", no. 124/11 and 46/17 Republika Srpska) & Regulation on monitoring of pollutants emissions in the air (Official Gazette of FBiH No. 33/03 and 4/10)]. In this context, no agreement on who will manage the GHG inventory and store the data at national level is in place. Bosnia and Herzegovina should adopt national legislation and transpose the MMR establishing the GHG inventory system at national level, as well as strengthen institutional capacities and formally define competences and responsibilities.
GEORGIA	No policy or regulatory framework defining the MRV scheme and its operation exists in Georgia. Compliance with the MMR is not clear at this stage, the establishment of policies and/or laws is essential for the sustainability of the MRV system.
KOSOVO*	Kosovo* adopted two administrative instructions with a view to aligning with the MMR in 2016. The "Administrative Instruction on a Mechanism for Monitoring GHG Emissions"[27] defines responsibilities and deadlines for providing data on GHG emissions, whereas the "Administrative Instruction for Monitoring GHG Emissions"[28] defines the governance and inter-institutional arrangements for providing data on GHG emissions. The aforementioned instructions partially transpose the requirements of the MMR. The Climate Change Strategy 2019-2028 and the Action Plan on Climate Change 2019- 2021 adopted in 2018 develop Kosovo's* capacity to meet its obligations under the UNFCCC and the EU. However, the national inventory system is not fully compliant with Regulation (EU) 525/2013.
NORTH MACEDONIA	The "Law on Environment" currently regulates the issue of monitoring of GHG emissions. According to this, the Ministry of Environment and Physical Planning is supposed to establish, develop, manage and coordinate a national system for a GHG emissions inventory. The national MRV system meets the UNFCCC reporting principles but there is lack of provisions defining competences. Therefore, an institutionalization of the GHG inventory system is still missing for the compliance of the national framework with MMR. To that end, the "Law on Climate Action" that

[27] Source : http://kryeministri-ks.net/repository/docs/UDHEZIM_ADMINISTRATIV_(QRK)_NR__01-2016_PER_MEKANIZMIN_E_PERCJELLJES_SE_EMISIONEVE_TE_GAZRAVE_SERE.pdf
[28] Source : http://kryeministri-ks.net/repository/docs/UDHEZIM_ADMINISTRATIV_(QRK)-_NR__09-2015_PER_PERCJELLJEN_E_EMISIONEVE_TE_GAZRAVE_SERE.pdf

EnC CP	Overview of the status of the national MRV's policy and regulatory framework
	is under preparation may deal with this issue as its general scope is the transposition of Regulation (EU) 525/2013.
MOLDOVA	The Republic of Moldova approved in February 2019 a decision (Official Gazette No. 38-47, 08.02.2019[29]) that transposes the key provisions of Regulation (EU) 525/2013 in the national inventory system. This decision establishes the national organizational structure and functionality of the national MRV system for GHG emissions and other policies and plans relevant to climate change.
MONTENEGRO	Montenegro's policy and regulatory framework surrounding the establishment of a formal national inventory system is relatively complete. A "Rulebook" including the list of gases and the method of preparing the GHG inventory and exchange of information transposes the requirements of the MMR since 2017. Furthermore, Montenegro's "Law on Protection from the Negative Impacts of Climate Change" adopted on December 2019, ensures the harmonization of national legislation with the international treaties on climate and incorporates among others MRV elements according to the EU ETS and the MMR.
SERBIA	General procedures and methods for collecting and archiving input data for the preparation of the national GHG inventory are defined in the Regulation on the methodology for data collection for the national GHG inventory adopted in 2016 ("Official Gazette of the RS", No 03/2016). To date, there are still no legal instruments to force operators refusing to share information on GHG emissions. The formulation of Serbia's Climate Change Law that is under preparation includes regulations for monitoring and reporting of emissions and for third-party verification of emissions and accreditation of verification bodies. The law is expected to transpose requirements of the EU ETS, as well as the MMR.
UKRAINE	Provisions on the creation and maintenance of national GHG inventory systems are included in Ukrainian legislation (Decree of 21/04/2006[30], Decree of 28/05/2008[31]). A partial transposition of the provisions of Regulation (EU) 525/2013 is achieved but further revision was needed to be in line with the MMR Regulation. In January 2018, the draft national legislative package on the MRV of GHG emissions was published laying the groundwork for Ukraine's planned ETS. In December of 2019, the Ukrainian Parliament adopted the MRV Law implementing the European standards for monitoring of GHG emissions. This MRV Law, entitled "On Principles of Monitoring, Reporting and Verification of GHG Emissions No. 377-IX"[32], entered into force on 26 March 2020, although it will be applicable as of 1st January 2021. The Ukrainian Ministry of Environmental Protection and Natural Resources is planning to launch an MRV system in 2021. Companies should be able to commence monitoring on 1 January 2021 and present their first monitoring reports for 2021 by 31 March 2022, i.e. the period for verification and reporting is estimated at 3 months. In this context, a special authorized agency on MRV of GHG and emissions trading should be established. After the MRV system has been put in place, Ukraine plans to develop separate legislation based on at least three years of data from the MRV system in order to transpose other relevant EU directives into its laws and establish an ETS.

[29] Source : http://lex.justice.md/index.php?action=view&view=doc&lang=1&id=379061

[30] Decree No. 554 of the Cabinet of Ministers on approval of the Order of operation of the system for the estimation of anthropogenic emissions and removals of greenhouse gases not controlled by the Montreal Protocol adopted on 21.04.2006

[31] Decree No 504 "On the formation and maintenance of the National Electronic Registry of anthropogenic emissions and removals of greenhouse gases" adopted on 28.05.2008)

[32] MRV Law, "On Principles of Monitoring, Reporting and Verification of GHG Emissions No. 377-IX [32] ", https://zakon.rada.gov.ua/laws/show/377-20

Experience reveals the critical role of a robust MRV in building trust and ensuring the integrity of a carbon pricing mechanism. This is because a solid, integrated MRV scheme, including verification and accreditation processes, guarantees transparency, high accuracy and comparability of emissions. In essence, a functional MRV system provides information about emission sources and trends, and so helps track progress towards climate change-related targets and steer mitigation actions so that the targets can be achieved. More so, reliable emissions data are the basis for the efficient allocation of allowances, which defines the success of an ETS system in particular at the early stage of its rollout. A sound MRV is thus the backbone of a carbon pricing mechanism and a well-functioning carbon market.

For this reason, CPs need to prioritize the establishment of sophisticated MRV systems in their jurisdictions, including precise guidelines and detailed instructions, as step number one for establishing a carbon pricing mechanism. The MRV system of the EU ETS provides a blueprint for this exercise, with key elements including:

- A monitoring plan for the different emitting installations;
- A verified annual emissions report;
- An EU Registry, namely a platform that holds accounts for participants to the EU ETS;
- A clear legal framework as a basis for enforcing MRV requirements on different stakeholders.

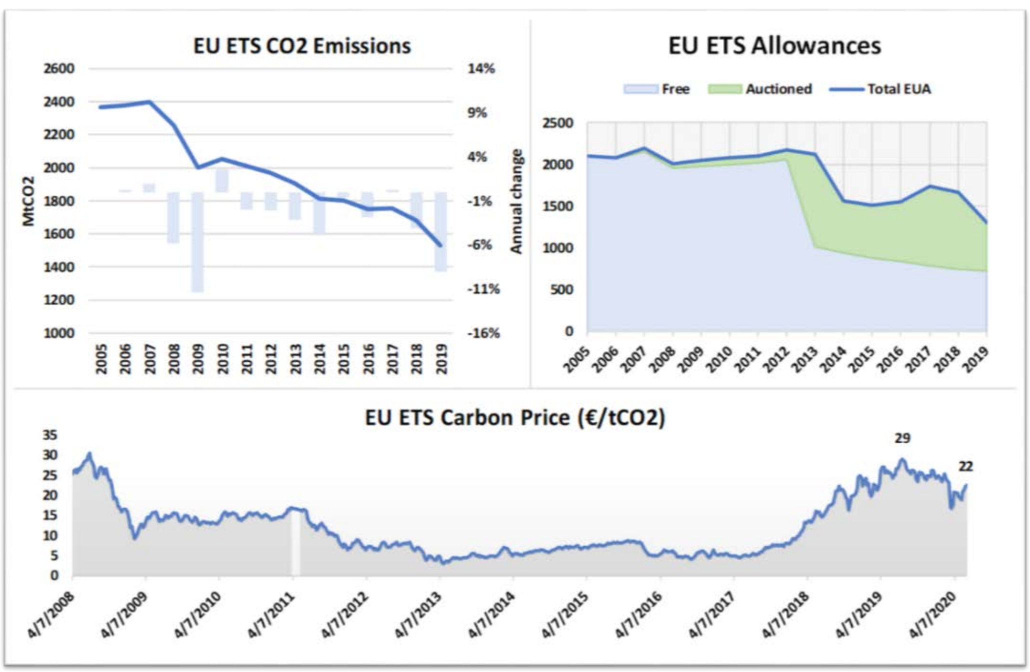
3.4 The case of the EU ETS

The EU ETS has been a cornerstone of EU climate policy and the key tool for reducing GHG emissions cost-effectively. The EU ETS covers around 45% of the EU's greenhouse gas emissions coming from the power sector, manufacturing industry, and aviation limited to flights within the European Economic Area. A cap is set on the total amount of certain greenhouse gases that can be emitted by installations covered by the system. The cap is reduced over time so that total emissions fall. Within the cap, companies receive or buy emission allowances, which they can trade with one another as needed. The limit on the total number of allowances available ensures that they have a value. After each year a company must surrender enough allowances to cover all its emissions, otherwise heavy fines are imposed. If a company reduces its emissions, it can keep the spare allowances to cover its future needs or else sell them to another company that is short of allowances. Trading brings flexibility that ensures emissions are cut where it costs least to do so. A robust carbon price also promotes investment in clean, low-carbon technologies.

The EU ETS was established in 2005 and the first two phases lasted until 2012. A milestone year was 2013, when the third phase kicked-off, with the abolition of free allowances in the power sector and auctioning becoming the default method. Auctioning has in fact resulted in carbon pricing becoming an integral part of internal accounting for companies. Another milestone year was 2019, when it was decided to increase the pace of annual reductions in allowances to 2.2% as of 2021 and to reinforce the MSR, in order to reduce the surplus of emission allowances in the carbon market, which was largely attributed to the economic crisis. The surplus of emissions was leading to lower carbon prices and a weaker incentive to reduce emissions. The stringency of the MSR led to a drastic reduction of the surplus of allowances and a surge in the price of carbon in 2019. The reduction of the surplus of allowances accelerated coal phase-out in all countries. Moreover, in this fourth phase of the EU ETS, new implementing legislation is introduced on the carbon leakage list, free allocation rules, the Innovation and Modernisation Funds, auctioning, monitoring, reporting, verification and accreditation, and on the Union Registry.

The proposal for a 55% GHG emission reduction target in 2030 implies the need to revise the EU ETS again, by establishing a strengthened cap to create the necessary long-term carbon price signal and drive further decarbonisation. This will require revisiting the linear reduction factor that defines the annual reduction of the cap beyond its current level of 2.2% to guarantee that the sectors covered by the EU ETS deliver the necessary emission reductions. At the same time, expanding the EU ETS scope to include emissions from the buildings and transport sectors through upstream coverage is under evaluation, along with the continuation of free allocation to prevent carbon leakage, even with the necessary strengthening of the cap. As discussed, alternative options to address leakage risks, including a Carbon Border Adjustment Mechanism targeting specific industrial sectors, are also under consideration. Revisions of the MSR should be expected as part of the planned review in 2021.

FIGURE 2: THE EVOLUTION OF THE EU ETS



4 Policy option for the Energy Community

The criteria for assessing and choosing between explicit and implicit carbon pricing used in the EnC_Carbon study include the market size, the level of competition, the maturity of institutions and the state of the economy overall in the CPs. From a public economics perspective, an implicit carbon pricing – a Cap and Trade – is considered the first best policy option. Grounded on the *Coase* theorem, the Cap and Trade system rests on the assumption that, if trading an externality is possible and if transaction costs are adequately low, bargaining will lead to a Pareto efficient outcome regardless of the initial allocation of property (i.e. permits). Nonetheless, transaction costs are usually high, since bargaining with a large number of individuals is difficult and increases because of social costs. Having in place large-scale installations and a complex system to accurately record and monitor emissions can help minimize transaction costs. Still though, the initial allocation of permits is difficult, inefficient and causes adverse effects under a system of free allowances. Auctioning emerges as a preferable choice, providing that the size of the market and the degree of competition are sufficiently large. Even with auctioning, the carbon price signal will be fluctuating, causing uncertainty to long-term corrective investment. Restricting the possible range of fluctuation is the purpose of measures such as the Market Stability Reserve, and the carbon price floor. However, such stricter measures may end up bringing the Cap and Trade system closer to a Carbon Tax.

On the other hand, taxation is viewed as a second-best policy choice. Underpinned by the *Pigou* theorem, taxation is an instrument in the hands of the state for mitigating divergences between marginal private costs and marginal social costs. Taxation is a second-best choice because it allows less freedom to the market forces to modify allocation, compared to the Cap and Trade system. Implementing a tax system is practically easy, but may be politically difficult due to social adverse effects. This is because a tax implies transfer payments, and as such, it reduces available income, causes distributional impacts, and may be vulnerable to social unrest. Moreover, deciding upon the level of the tax is difficult and often arbitrary.

In light of this, the study proposes a *Cap and Trade* system to apply in the power and district heating sectors in each CP, and be linked later on to the EU ETS. Furthermore, the CPs may consider introducing a *carbon tax* in the transport and building sectors. Both policy options cannot cover the same sector simultaneously, as in that case a tax would reduce the liquidity of certificate trading. A carbon price floor is not part of the EU ETS and has adverse effects on competition. In accordance with the policy assumption that CPs eventually join the EU ETS, a carbon price floor is not applicable and not addressed as part of the policy option.

4.1 Carbon tax

Currently all countries in the region impose excise taxes on oil products and some on natural gas. The tax rates often differ by sector and a carbon tax is absent or too small, almost insignificant. Additionally, taxation of inputs to power generation or district heating does not exist or is very small. In CPs, heating oil is less taxed than in EU MS, diesel is less taxed than gasoline and no minimum tax applies on natural gas and electricity. The taxation gap exists irrespective of the calculation basis. As emission factors per fuel are similar across sectors, the same gap exists also if the tax calculation is per ton of CO2.

The tables below present the excise taxes in the region (also in unit of energy and unit of emissions in section 10.2).

TABLE 9: EXCISE TAXES IN THE REGION

In EUR	Gasoline (per lit)	Diesel (per lit)	LPG (per lit)	Kerosene (per lit)	Fuel oil (per lit)	Heating oil (per lit)	Nat. Gas (per m3)	Coal (per kg oe)	Electricity (per MWh)	VAT
ALBANIA	0.514	0.514	0.064	0.160	0.030	0.297	0.000	-	-	20%
NORTH MACEDONIA	0.350	0.195	0.079	0.181	0.036	0.051	0.000	-	-	18%
KOSOVO*	0.360	0.360	0.150	0.150	0.025	0.150	0.000	-	-	18%
MONTENEGRO	0.460	0.350	0.124	0.156	0.020	0.120	0.000	-	-	21%
BOSNIA & HERZEGOVINA	0.381	0.355	0.203	0.152	0.023	0.228	0.000	-	-	17%
SERBIA	0.369	0.252	0.126	0.126	0.027	0.252	0.000	-	-	20%
UKRAINE	0.214	0.140	0.000	0.000	0.000	0.000	0.000	-	0.001	20%
GEORGIA	0.315	0.197	0.158	0.158	0.020	0.158	0.079	-	-	18%
MOLDOVA	0.340	0.143	0.214	0.143	0.026	0.143	0.340	-	-	20%
BULGARIA	0.363	0.330	0.174	0.330	0.020	0.330	0.023	0.013	1.000	20%
ROMANIA	0.373	0.342	0.136	0.476	0.016	0.342	0.146	0.013	1.000	19%
GREECE	0.700	0.410	0.430	0.410	0.038	0.410	0.079	0.013	1.000	24%

An issue that arises from the consideration to introduce a carbon tax relates to whether this would replace an existing excise tax or be imposed on top of that excise tax. Because of significant variations among current excise taxes on oil fuels, converting these excise taxes into a single carbon tax that applies uniformly across fuels would result in some fuels then being significantly taxed. Indicatively, an excise tax of 0.4€/lit of an oil product (gasoline) is approximately equivalent to a carbon tax of 150€/tCO2. For fuel oil, the current excise tax is equivalent to only 7€/tCO2, for heating oil to 50€/tCO2 and for natural gas almost zero. For this reason, the study proposes the carbon tax to be complementary to existing excises taxes in the CPs. In that sense, be as high as needed to close the gap with the average tax levels in the three EU MS in the corresponding sectors.

The study recommends the CPs to consider adjusting the applied excise taxes on fuels used in transport and buildings to the average taxation levels applied respectively in the three EU MS. The idea is to avoid taxing heavily through equalization, which would create significant affordability issues. This adjustment prepares the ground for further rise in taxes on fossil fuels in transport. Specifically, for oil products, i.e. gasoline and diesel, the study recommends aligning excise taxation where applicable, while for natural gas, it is proposed to apply excise taxation at a lower level than the carbon emission analogy and so promote gas as a cleaner substitute of polluting fuels in heating. For coal and lignite used in heating, it is recommended to raise excise taxation very gradually, due to the risk of black market and adverse social effects, since rural and low-income households are using such fuels. Exemption of jet fuels from taxation could be maintained as in the EU MS.

TABLE 10: PROPOSED MINIMUM CARBON TAX FOR HEATING OIL IN CPS

In EUR	Heating oil (per lit)	Complementary excise tax (per lit)	Complementary tax expressed in CO2 (carbon tax)
ALBANIA	0.297	0.063€/lt	0.0056€/CO2e

BOSNIA & HERZEGOVINA	0.228	0.132€/lt	0.035€/CO2e
GEORGIA	0.158	0.202€/lt	0.053€/CO2e
KOSOVO*	0.150	0.210€/lt	0.056€/CO2e
MOLDOVA	0.143	0.210€/lt	0.056€/CO2e
MONTENEGRO	0.120	0.24€/lt	0.064€/CO2e
NORTH MACEDONIA	0.051	0.309€/lt	0.082€/CO2e
SERBIA	0.252	0.108€/lt	0.029€/CO2e
UKRAINE	N/A	N/A	N/A

4.2 Cap and Trade policy option

Cap and Trade applies in stages. First, CPs establish national measures, i.e. MRV and a system of preconditions for allowances to be issued, managed and traded at national level. Then, national systems are linked under a coordinated EnC system that allows for cross-border trading between CPs and then with EU MS, paving the way for the adherence to the EU ETS, first under a transitional regime and then in full.

Stage 1: Internal carbon pricing – certificates

Emitting entities assign a carbon price to carbon emissions for all internal decisions concerning operation and investment. The state allocates emission allowances to the entities up to a targeted level of emissions and if the entity has excess allowances, then the state provides them with a credit; otherwise the entity pays a penalty to the state. Both are calculated using an administrated carbon price. A robust MRV scheme guarantees the most efficient allocation of allowances and so emitting installations must make sure to have such scheme in place. At this stage, emitters are required to modify business plans without having to pay for or trade allowances.

Stage 2: Internal carbon pricing – traded at a national level

Allowances are now traded between entities in each CP. Bilateral transactions and an organized market for allowances may coexist, where the carbon price is market-based, but a carbon price floor may apply. The state may act as a buyer and a seller to balance the market and increase liquidity of allowances. At this point, it is worth noting that granting free allowances does not eliminate costs fully. In fact, there has to be a cap on total allowances, meaning that total allowances granted for free have to be lower than anticipated carbon emissions, and the gap will have to increase over time. This will create a price signal and provide incentives for abatement. In order to reduce emissions and meet the cap without buying extra allowances from the market or from the state, the emitting entity subject to allowances will have to pay for modifying the fuel mix and efficiency. In the impossibility to meet the emissions cap on its own, the entity will have to pay for purchasing allowances.

In practice, what happens is that the administration forecasts for next year the likely needs for allowances so that entities may fully justify the expected emissions. Then, it issues a lower amount of new allowances, considering mainly two aspects: (a) the emission reduction target, (b) the surplus of emissions in circulation (i.e. allowances issued in the past that have not been used yet to justify emissions). An administrative body needs to be entrusted with the task of defining the amount of new allowances to issue every year. This is a policy decision of course, not a technical one. There are two approaches: setting up an algorithm to calculate the amount of new allowances (this is the MSR) or deciding every year or every five years ad hoc. The administrative body is either a government or an international organisation. Such an organisation has not been yet defined for the CPs. Until joining the EU ETS, where the European Commission has been delegated to act as an administrative body, CPs may proceed either bilaterally or in a regional, coordinated manner. Coordination matters for paving the way for *Stage 3*, unless cross-border trading is based on bilateral agreements. If CPs opt for coordination, either they assign this task to a body or they coordinate by bargaining the issuance of allowances ad hoc.

Stage 3: Cross-border trade between CPs and EU MS

CPs form bilateral agreements with EU MS and the allowances need to be legally recognized and accepted by the EU ETS system. For this to happen, CPs need to have transposed the (adapted) EU ETS Directive and accompanying legislation in their jurisdiction and fulfil all the accompanying legal preconditions in a harmonized way. These mainly concern the settlement of financial transactions for the minimization of risks associated with the transfer of financial instruments and payments, the liquidity of the market, transparency and integrity. Moreover, the existence of a level-playing field in power trading is of utmost importance. A level playing field postulates scrapping of subsidies to mines or power companies, abolishment of under-costing electricity pricing and banning the practice of not pricing fully the exports of electricity.

The amount of allowances missing from the market (surplus minus current demand for allowances) and the variation in marginal abatement costs between subject entities will define how liquid the regional market of allowances is. The broader the market, the higher the probability to have a large variety of marginal abatement costs, where emitters are incentivised to engage in cross-border trading of allowances, in order to curb their abatement costs. Such conditions make for a liquid allowance market and a gradual adhesion of the CPs into the EU ETS. Still, in the event that broader coordination does not occur and the market is confined within national borders, a CP may search for a bilateral agreement with another country to broaden the market.

FIGURE 3: CAP AND TRADE POLICY OPTIONS

Stage 1: Internal carbon pricing – certificates

- Subject entities assign a carbon price to carbon emissions for all internal decisions for operation and investment
- State allocates emission allowances and provides a credit; otherwise emitters pay penalty to the state
- Administered carbon price and no trade of allowances

Stage 2: Internal carbon pricing – traded at a national level

- National trade of allowances under bilateral transactions or within a market of allowances
- State acts as a buyer and a seller to balance the market and increase liquidity
- The carbon price is market-based, but a carbon price floor is suggested to apply

Stage 3: Cross-border trade

- Cross-border trade of allowances based on bilateral agreements between the countries
- Reasonable pre-conditions including for financial transactions, market liquidity and transparency and level-playing field
- Allowances are still granted for free

Stage 4: Adherence to the EU ETS under a transitional regime

- Full trade of allowances within the EU ETS
- Free allowances during the transition period are possible

Stage 5: Full integration in the EU ETS

- Free allowances abolished, all allowances auctioned

Stage 4: Adherence to the EU ETS under a transitional regime

In Stage 4, the CPs are permitted to engage in full trading of allowances within the EU ETS system under a transitional regime. This implies that free allowances are still possible in parallel with auctions. From auctioning, the CPs receive revenues (transfer payments from emitters) and possibly an additional pot of money as public revenues from a dedicated modernisation and decarbonisation fund. This money transfer serves to fund transformation and positive externalities in order to increase flexibility to undertake the necessary restructuring. Access to this funding may be possible already in Stage 3 and intensify during Stage 4, but end when integration to the EU ETS takes place (Stage 5). Free allowances continue to be granted to the energy-intensive industries most affected by carbon pricing and to the power sector as well. For energy-intensive industries, free allowances would be subject to sustainability-related aspects such as performance-based benchmarking methodology, carbon leakage risk assessment etc., as in the EU ETS. Similarly, free allowances to the power sector would be subject to sustainability related conditionalities, i.e. progressively diminishing transitional free allocation granted against investments in modernisation and decarbonisation in the power sector (as foreseen under Article 10c of the ETS Directive).

Already in Stage 3 and definitively in Stage 4, the CPs need to fulfil all preconditions associated with the functioning of a Cap and Trade system, summarized again below:

- Liquidity, security and transparency of the market, which ensure smooth cross-border trading;
- Sound domestic market functioning and coupling between markets;
- Level playing field in competition;

- Scrapping of national state aids and subsidies;
- Revenue recycling rules

Stage 5 – Full integration in the EU-ETS

This is the final and most advanced stage in the establishment of a Cap and Trade system. All allowances are auctioned and CPs are ready to adhere to the EU ETS. In Stage 5, transparency in the use of state revenues and the existence of safeguards to ensure these are channelled towards activities promoting decarbonisation are crucial. The duration of the stages may vary per CP depending on:

- the degree of responsiveness to carbon pricing (particularly relevant for the most vulnerable CPs);
- the threat of social and industrial adverse effects;
- the potential of attracting decarbonizing investment; *and*
- the expected positive externalities (new industrial growth)

In the following section, the scenarios for the introduction of carbon pricing are defined. Each scenario reflects different policy assumptions, which have been quantified using the PRIMES-IEM model. The rationale underpinning key assumptions, the methodology for modelling the assumptions, the input data and projections of the model are presented below.

5 Modelling methodology

5.1 Assumptions for the scenario design

Two critical aspects have informed the design of the scenarios: (i) the pace and timeframe of introducing carbon pricing in the CPs; (ii) whether power and gas markets integrate across CPs and with the EU or remain fragmented.

On the first aspect, the main distinction is made between full and gradual carbon pricing. *Full carbon pricing* on power generation and district heating foresees the 100% auctioning of allowances from 2025 onwards across CPs with no exemptions. Such an assumption, extreme as it may seem, serves the purpose of formulating contrasted scenarios and a robust policy storyline. Simply reflecting the current policy context would make policy conclusions critically unambitious to the point of becoming irrelevant. Under *gradual carbon pricing*, auctioning of allowances applies at different rates and speeds in each CP in the course of the projection period (Table 11) and for the remaining emissions free allocation applies. The underlying factor for considering a gradual implementation is the existence of unequal possibilities among CPs to respond to carbon pricing. There are CPs with effectively no dependence on fossil fuels for power generation and others with high levels of dependence, thus exposure to carbon pricing effects.

On the second aspect, the distinction concerns market integration *vs.* market fragmentation. Market integration refers to the integration of the power and gas markets of the CPs and with the EU. It signifies an increase in NTCs to a minimum of 70% of the thermal capacity of the respective interconnections to be available in the wholesale and balancing markets from 2025. Market integration also entails allocation of interconnection capacity to be based on market clearing prices in day-ahead and intra-day markets and market coupling to apply to all three market stages, i.e. for balancing and reserves also, apart from day-ahead and intra-day. What's more, under market integration conditions, ancillary services procurement can be cross-border and power systems operate under a regional coordination system. For the gas sector, market integration presupposes that gas infrastructure develops in the CPs, allowing for better connectivity and access to diverse gas sources, i.e. LNG and inverse-flows. Under gas market integration, gas supply possibilities increase in the Western Balkans and average gas prices decrease (when compared to fragmented gas markets).

TABLE 11: PROPOSED AUCTIONING RATES UNDER GRADUAL CARBON PRICING

COUNTRY	2025	2030	2035	2040
BOSNIA & HERZEGOVINA	25%	30%	75%	100%
SERBIA	25%	30%	75%	100%
UKRAINE	25%	30%	75%	100%
NORTH MACEDONIA	30%	65%	85%	100%
MONTENEGRO	30%	65%	85%	100%
KOSOVO*	15%	35%	65%	85%
ALBANIA	100%	100%	100%	100%
GEORGIA	100%	100%	100%	100%
MOLDOVA	100%	100%	100%	100%

Market fragmentation on the other hand implies that NTCs remain at today's levels and that the allocation of capacities does not depend on wholesale markets. Markets are not coupled and the provision of ancillary services and reserves takes place within national borders. Likewise, gas market fragmentation implies lack of gas-to-gas competition and poor development of gas supply, which in turn discourages investment in gas power plants.

A summary of the storyline supporting each scenario is presented below.

- **Baseline (BSL):** The Baseline scenario does not foresee the introduction of carbon pricing, but assumes the continuation of current NTCs and policies for RES support. It is therefore not a strong policy case; rather, it offers a benchmark against which the other four (4) scenarios are developed and assessed.
- **Baseline with Cross-Border Adjustment Carbon Tax (BSL_CBAT):** A variant of the Baseline scenario, which assumes that a carbon tax equal to the EU ETS carbon price applies on exports from CPs to EU in proportion to CO2-intensity of the country of origin.
- **Full Carbon Pricing and Market Integration (Full_CP-M_Int):** CPs apply full carbon pricing with full auctioning of allowances from 2025 onwards, with no exemptions. CPs also proceed to the opening of electricity trade and market integration no

later than 2025 in order to remedy the adverse effects of carbon pricing. Meanwhile, gas infrastructure develops, easing the access to and sharing of gas coming from diverse sources, which benefits the development of variable RES. CPs develop national ETS systems in a coordinated manner, with the view to linking them with the EU ETS in 2030.

- **Full Carbon Pricing and Market Fragmentation (Full_CP-M_Fr):** CPs apply carbon pricing fully, yet markets remain fragmented due to the persistence of national specificities, and so each CP embarks on an individual path to the EU ETS. The scenario assumes NTC values remain at current levels, markets are not coupled while balancing and reserves continue to rely on domestic resources. The negative price implications for consumers are significant and the transition hard to manage, particularly for the CPs that depend the most on solids.
- **Gradual Carbon Pricing and Market Integration (Gr_CP-M_Int):** CPs adopt carbon pricing in a coordinated way, though under a transitional period, where different auctioning rates and timeframes apply from country to country. This is to accommodate the different levels of flexibility to carbon allowing most vulnerable CPs to help their emitters adapt more easily and protect consumers from strikingly high electricity and heat prices.
- **Gradual Carbon Pricing and Market Fragmentation (Gr_CP-M_Fr):** CPs adopt carbon pricing based on their flexibility levels. Power and gas markets remain fragmented which takes a toll on CPs that are most exposed to carbon pricing. Market fragmentation prevents those CPs in particular from having access to low-carbon resources, thus from adjusting their power generation mix to a reasonably high carbon emissions price. Despite being gradual, the application of the carbon price brings with it significant price increases and forces consumers to bear unreasonably high consequences, that cannot be remedied under market fragmentation conditions.

TABLE 12: SUMMARY OF SCENARIO DEFINITION

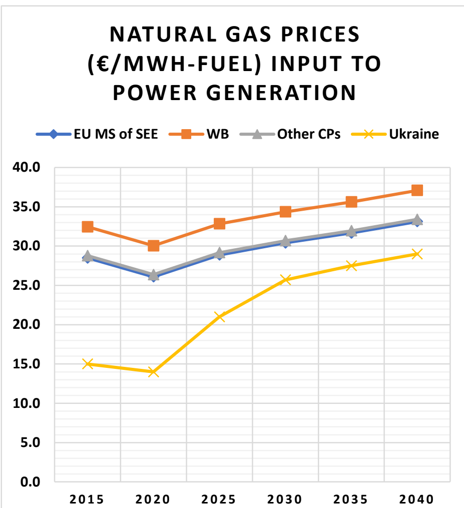
SCENARIOS	ACRONYM	AUCTIONING	MARKET INTEGRATION	CBAT	OTHER POLICIES
Baseline	BSL	NO	NO	NO	Opt-out applied, RES policies as BSL
Baseline & Cross-Border Adjustment Carbon Tax	BSL_CBAT	NO	NO	YES	Opt-out applied, RES policies as BSL
Full Carbon Pricing & Market Integration	Full_CP-M_Int	FULL	YES	NO	Opt-out applied, RES policies enhanced
Full Carbon Pricing & Market Fragmentation	Full_CP-M_Fr	FULL	NO	NO	Opt-out applied, RES policies enhanced

Gradual Carbon Pricing & Market Integration	Gr_CP-M_Int	PARTIAL	YES	NO	Opt-out applied, RES policies enhanced
Gradual Carbon Pricing & Market Fragmentation	Gr_CP-M_Fr	PARTIAL	NO	NO	Opt-out applied, RES policies enhanced

5.1.1 Fuel and carbon prices

Natural gas prices are end-user prices. In that sense, they include balancing costs and grid tariffs. Western Balkan CPs are assumed to have systematically higher gas prices, yet not by much, compared to the three EU MS studied. In Ukraine, gas prices are much lower due to subsidies, though a steady convergence with other countries is observed.

FIGURE 4: ASSUMPTION OF NATURAL GAS PRICES



The modelling assumes that average natural gas prices in imports tend to increase only slightly during the decade, reflecting improved global gas market conditions of supply thanks to rising LNG supplies. In the case of market integration scenarios, supply conditions improve and so the modelling assumes higher convergence of gas prices between the CPs and the EU MS. The gas price projections are based on the PRIMES model-based projections underpinning the impact assessment of the Green Deal.

In the full carbon pricing scenarios, the modelling has applied the same carbon prices across CP. These are in accordance with the Baseline scenario of the latest projection of the PRIMES model for the EU ETS, which foresees further stringency of the Market Stability Reserve (MSR) until 2040. The projection is included in the Impact Assessment underpinning the recent proposal for a Climate Target Plan, the cornerstone of the European Green Deal. Prices start at EUR 26.5/ton in 2025, reflecting current EU ETS prices, increase smoothly to EUR 32/ton in 2030 before climbing to EUR 53/ton in 2035 and EUR 80/ton of CO2 emissions in 2040. In the gradual carbon pricing scenarios, the modelling has applied different carbon prices among the CPs, depending on the flexibility of their system towards carbon pricing. Prices have been selected as most representative assumptions reflecting fair effort and mitigation of adverse economic impacts in each CP.

TABLE 13: ASSUMPTION OF CARBON PRICES

EU-ETS in EUR/tnCO2	2015	2020	2025	2030	2035	2040
All CPs	7.50	12.00	26.50	32.00	53.00	80.00
Carbon Price EU ETS in Gradual Scenarios in EUR/tnCO2	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
BG	7.5	12	26.5	32	53	80
GR	7.5	24	26.5	32	53	80
RO	7.5	24	26.5	32	53	80
AL	0	0	26.5	32	53	80
BA	0	0	6.625	16	39.75	80
GE	0	0	26.5	32	53	80
KV	0	0	3.975	11.2	34.45	68
MD	0	0	26.5	32	53	80
ME	0	0	7.95	20.8	45.05	80
MK	0	0	7.95	20.8	45.05	80
RS	0	0	6.625	16	39.75	80
UA	0	0	6.625	16	39.75	80

5.1.2 Net Transfer Capacities

New interconnections currently under construction (Table 14) add significant cross-border capacity, causing a two-fold increase of total interconnection capacity by 2025 in the region. At present, however, the values of NTCs are small in all countries, with less than 30% of interconnection capacities being on average available for commercial operations in the wholesale and balancing markets (Figure 5). Under market fragmentation, NTCs remain at current levels, whereas with market integration the 30% value increases significantly and no less than 70% starting 2025.

FIGURE 5: NTCS UNDER BASELINE CONDITIONS (2018)

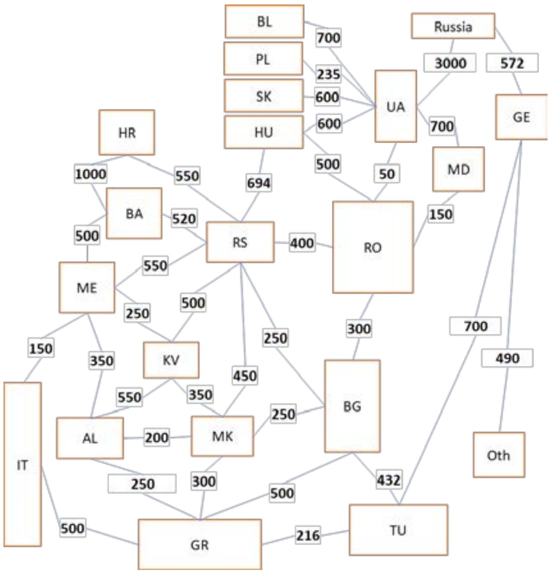


TABLE 14: PLANNED INTERCONNECTIONS IN THE ENC REGION

COUNTRY 1	COUNTRY 2	COMMISS.YEAR	THERMAL CAPACITY OF NEW INTERCONNECTOR (MW)
ALBANIA	NORTH MACEDONIA	2023	1330
BOSNIA & HERZEGOVINA	SERBIA	2026	1300
BOSNIA & HERZEGOVINA	CROATIA	2030	1300
BULGARIA	ROMANIA	2020	1300
BULGARIA	GREECE	2023	1500
MONTENEGRO	ITALY	2025	600
SERBIA	ROMANIA	2030	1300
SERBIA	ROMANIA	2030	1300
SERBIA	MONTENEGRO	2026	1300
ROMANIA	UKRAINE	2025	1300
GEORGIA	AZERBAIJAN	2022	625
GEORGIA	RUSSIA	2023	1000
GEORGIA	TURKEY	2022	350
GEORGIA	TURKEY	2025	350

5.1.3 Balancing and storage

The electricity and heat modelling represents the optimum capacity expansion and the unit commitment algorithm for the interconnected power system of the region simultaneously. The optimization seeks to minimize total system costs, including fuel, taxation, non-fuel carriable, fixed and capital (investment) expenditures over a time horizon until 2040. The cost function also includes penalty costs for load, RES, and reserve curtailment. The optimization constraints include the balancing of electricity demand, considering it as given, and various power reserve types, which form the ancillary services. The model endogenously calculates all balancing costs, which are reflected in the average electricity prices. Since the model determines endogenously the capacity expansion of the system, it chooses the most cost-optimal mix of resources, used to provide ancillary services to the system. The model also includes novel storage technologies, such as batteries and hydrogen-based power-to-X, for which investment and operation are endogenous together with hydro pumping capacities. Regarding the central role of gas in the provision of ancillary services, as opposed to pumped storage and/or batteries, the model relies on a very detailed database[33] with robust techno-economic data for each technology. While battery costs decrease in the future, gas units are more competitive because they are not only used for ancillary services but for energy purposes too. Therefore, investment in gas units is a more cost-efficient solution.

5.2 Model approach, input data and projections

To assess the implications of carbon pricing in the EnC, the study makes use of PRIMES-IEM (Internal Electricity Market), a South-East European region interconnected model. The model covers the Western Balkan countries as well as Romania, Bulgaria and Greece. The assessment for Ukraine, Moldova and Georgia rests on single country models. The years covered are 2015 (calibration to that year), 2020 (estimation using data until 2018), 2025, 2030, 2035 and 2040. PRIMES-IEM simulates the electricity system and market operation along with the merit order with ancillary services, and calculates endogenously the reserves and balancing resources. By applying various assumptions for the degree of market integration, reflected in different inputs of NTC values and market coupling, as well as for demand response and storage, the model produces different outputs regarding the intensity of cross-border trade, the size of the investment and the associated costs (Figure 6). This feature in the model allows to see from an endogenous perspective how CPs influence and depend on each other when exchanging balancing and reserves, seeking to decarbonise their power and district heating sectors in the most cost-efficient way. The model achieves an optimal power flow solution while endogenously identifying the investment at the same time. This way the model offers a clear simulation of how market integration affects the power system.

TABLE 15: PROJECTIONS OF THE PRIMES-IEM MODEL

1	Hourly generation by the power plants
2	Power charging and discharging of storage devices
3	Reserve power for ancillary services
4	Interconnection flows
5	Capacity-related decisions for investment, refurbishment and decommissioning
6	Heat production via heat-only production plants and CHP plants

[33] https://ec.europa.eu/energy/sites/ener/files/documents/2018_06_27_technology_pathways_-_finalreportmain2.pdf

7	Interconnections, NTCs, reserves, and degree of market coupling for balancing and reserves;

The set of input data presented to and validated by national stakeholders and the EnC Secretariat, used as input in the model, concern:

TABLE 16: INPUT DATA OF THE PRIMES-IEM MODEL

1	Demand for electricity
2	Fuel and carbon prices
3	Data on individual power plants, i.e. decommissioning, under construction, candidates for possible investment, technical-economic data
4	RES potential and existing or planned policy support schemes for RES
5	Fuel quantity limitations, where applicable
6	Technical operation constraints – opt out decisions
7	Interconnections, NTCs, reserves, and degree of market coupling for balancing and reserves
8	Heat demand and supply assumptions

In fact, demand for electricity and heat was modelled as price inelastic in order to isolate the effects of carbon pricing and the impact of market integration on the power system. Hence, demand for electricity and heat is not an output of the model but an assumption based on projections related with economic growth. Improvement of living standards drives a sustained increase in demand for electricity and heat, especially in low-income countries. Increased convergence is assumed in Albania, Montenegro and Bosnia and Herzegovina. In North Macedonia and Serbia, the gap magnifies due to economic restructuring causing loss of energy intensive industries. A slowdown of electricity demand is projected in Bulgaria and Romania, while in Greece demand grows fast until 2030, owing to the interconnection of most islands to the mainland system. In Ukraine, electricity demand has been growing only slowly, yet economic recovery is expected to prevail and sustain a moderate growth in the future. Steady growth in electricity demand is not expected to cease in Georgia. In Moldova, electricity demand may be increasing, yet at a slow pace, compromised by huge energy system inefficiencies and limited generating capacity.

District heating plays an important role in the CPs, providing energy in industry and residential heating. Only Albania, Montenegro and Georgia do not have functioning district heating systems. The upcoming incorporation of the Clean Energy for All Europeans package in the EnC acquis will emphasize the role of district heating in scaling-up the decarbonisation of the energy system in the CPs. Currently, many district heating systems are reported to be in poor condition with high distribution losses and low overall efficiency. Most systems run on solids and gas. Biomass can be used in district heating, either alone or co-fired with fossil fuels; however, the proportion of the total district heating currently supplied by biomass fuels is low and projected to be present in Bosnia and Herzegovina and Ukraine only.

FIGURE 6: GDP AND DEMAND FOR ELECTRICITY BY COUNTRY

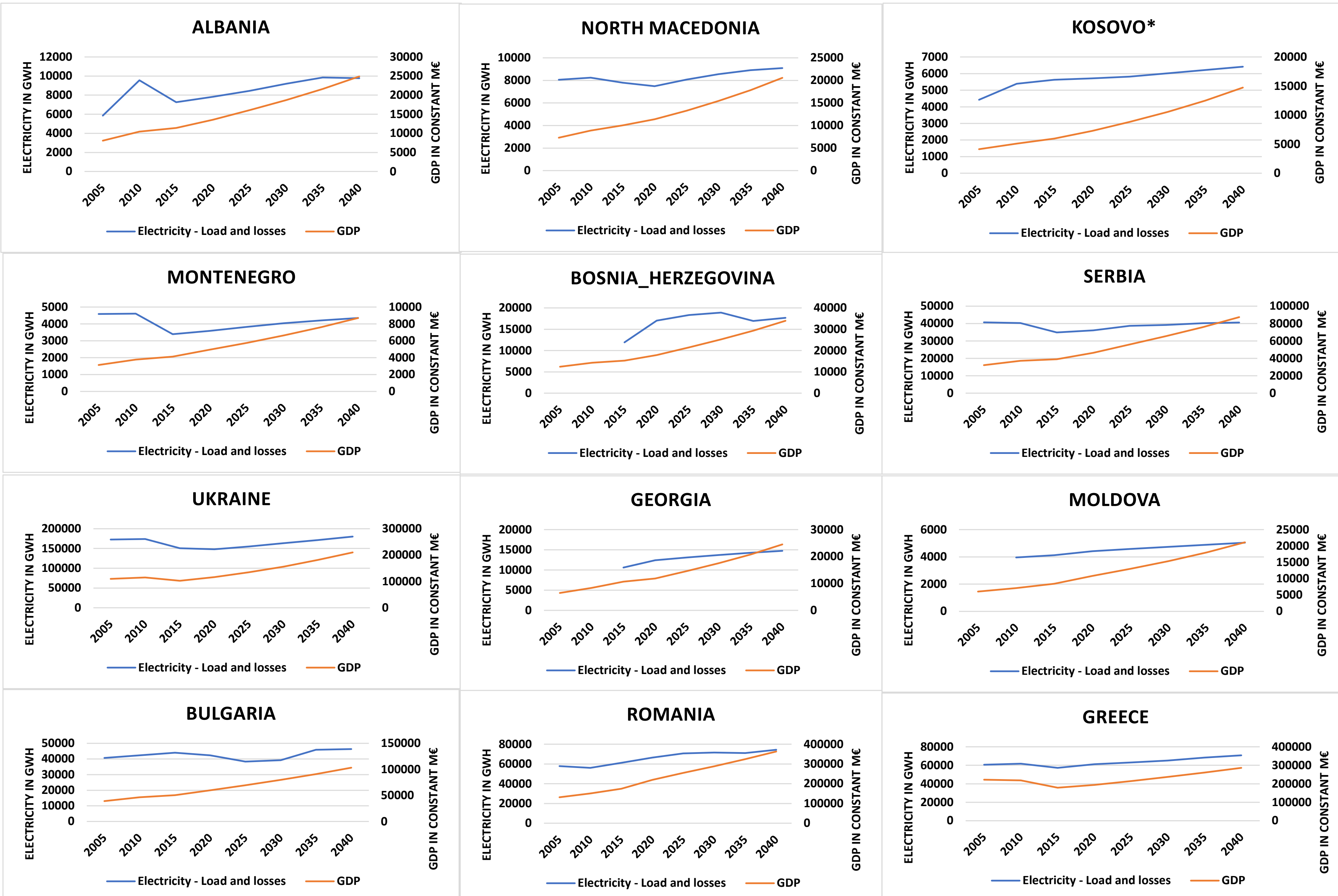
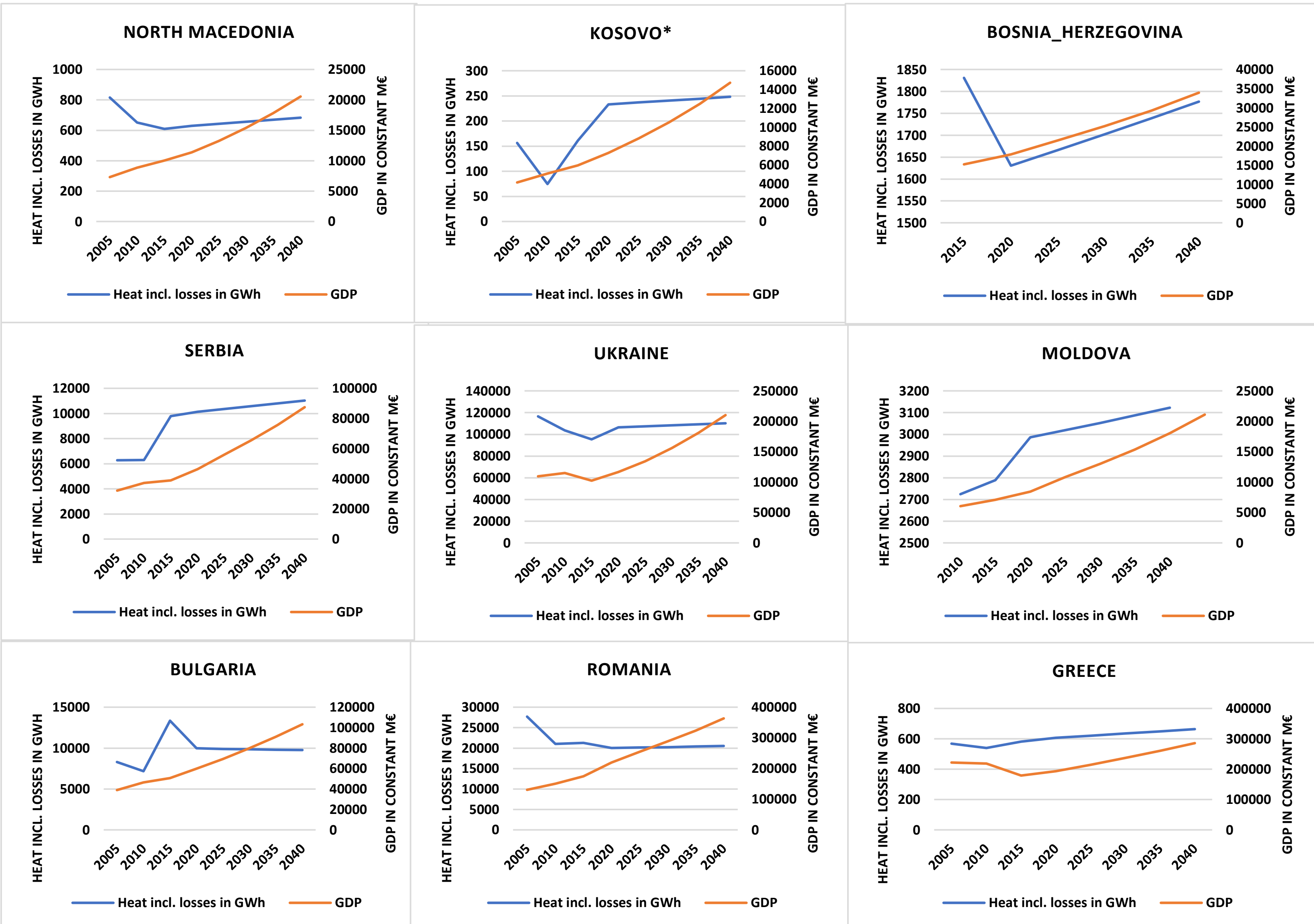


FIGURE 7: GDP AND DEMAND FOR HEAT BY COUNTRY



5.2.1 Calculation of electricity prices

The projections of the model concern retail electricity prices. Wholesale, day-ahead prices are based on ex-post calculations. After the model determines the capacity expansion mix, a special routine simulates the operation of a day-ahead energy-only market. Wholesale market prices are the output of this simulation and reflect the system-wide marginal price, in the context of a pure energy merit order dispatching. System-wide marginal prices reflect the marginal cost of the most expensive power plant that would be needed to serve an additional demand for electricity. Obviously, the system-wide marginal prices do not depend on RES, as the latter bid zero prices. Moreover, they do not reflect system costs for balancing RES or for procuring ancillary services, since the day-ahead market is a pure energy market. However, balancing and ancillary services costs, along with recouping of capital and fixed operation and maintenance costs, all form part of the total costs in the model. In fact, to perform the impact assessment of policies, one should factor in all kinds of costs; wholesale prices only represent partially the costs borne by final consumers. Under market coupling, in the absence of congestion in the interconnectors, day-ahead wholesale prices are the same across coupled markets. If market coupling does not apply, the wholesale prices are different. The same applies in intra-day and balancing markets, when coupled. It is essential to keep in mind that day-ahead wholesale electricity prices do not coincide with retail prices, for at least three reasons:

First, RES participate in the day-ahead markets, but they submit zero-price bids, as they have zero marginal costs. The wholesale day-ahead market prices decrease when RES increase, due to the zero-price bidding, but also because day-ahead markets are pure energy markets and costs do not include balancing costs and ancillary services (reserves). Therefore, the wholesale market prices are not sufficient for RES to recoup all capital and maintenance costs. For this reason, either RES rely on feed-in tariffs and/or feed-in premium support schemes to recover costs, or get revenues from consumer payments as part of bilateral contracts (power purchase agreements or contracts of economic differences). At the end, all costs incurred by the system and the investors who operate power plants effectively pass through to consumer prices, otherwise the power sector would be in a financial deficit. Therefore, it is reasonable for the model to assume consumer-based revenues matching all costs of the sector. It is also reasonable not to include costs of plants that are not used or not yet fully amortized; otherwise, consumers would have to pay for stranded assets. Stranded assets differ by scenario, as they depend on the degree of market integration.

Second, balancing and reserves entail costs and probably scarcity rents, which are not part of the day-ahead wholesale market. Market integration scenarios assume that market coupling applies also on intra-day and balancing markets and concern procurement of ancillary services – reserves. The broadening of the markets implies that scarcity pricing (when balancing resources and reserves are scarce) relaxes, thanks to the sharing of balancing resources. This makes the integration of RES easier and reduces costs passed through to consumer prices. Naturally, congestion and scarcity pricing cases are fewer under market integration and thus both wholesale and retail prices converge across the region. However, the convergence of wholesale prices is higher than convergence of retail prices, since retail prices still have to recoup national costs associated with system reserves and capex differences, which cannot fully smoothen out despite full market integration. Full convergence of retail prices can only happen in the long term, when all national costs are amortized and the regional power system operates in an optimal way.

Third, the entire power system may include capacities not yet amortized or plants in reserve for which electricity suppliers may succeed recouping fixed costs from consumer prices. All three reasons imply that day-ahead wholesale clearing prices are on average lower than retail prices. Still, it is possible to see the opposite, at least in the short-term. Scarcity rents (possible when market power is exerted) may imply wholesale market clearing prices, both in day-ahead and balancing, to be excessively high; *higher* than average system costs *and* average customer prices. The electricity-pricing algorithm of the PRIMES-IEM model applies a *Boiteux and Ramsey* methodology to estimate end-user electricity prices by consumer category. The calculation of electricity prices assumes that the sellers recover operation, fixed and capital costs of electricity generation under perfect competition conditions, which allow pricing electricity on average according to the long-run marginal system costs (i.e. total marginal cost of optimal system expansion).

6 Impact assessment of the scenarios

6.1 Outlook of power capacities and generation

6.1.1 Albania

Historically, power generation in Albania has relied exclusively on hydropower. This trend continues under the Baseline scenario. Dependence on coal is non-existent, which gives Albania the advantage to decarbonise its electricity sector in a swift and cost-effective manner. However, the Baseline scenario foresees variable RES to represent just below 20% of total generation in 2040, which falls short of the country's notable potential. Active policy support could drive the development of variable RES at a much faster pace. Meanwhile, the shares of gas remain marginal, with the commissioning of a small gas plant of 97 MW (Vlora) by 2025, projected to cover just 2% of total generation and provide reserve services to the system.

Considering that Albania has no coal reserves, the introduction of carbon pricing hardly exerts any pressure on power generation. Market integration benefits Albania on multiple fronts. First, it drives an increase in variable RES, mainly wind and to a lesser extent solar, after 2030. Second, it enables the cross-border sharing of balancing resources, which allows Albania to use its resources more efficiently. This implies that under market integration conditions, there is no need to use the gas plant and Albania becomes a net exporter of hydro-based electricity.

FIGURE 8: POWER GENERATION OUTLOOK FOR ALBANIA ACROSS SCENARIOS

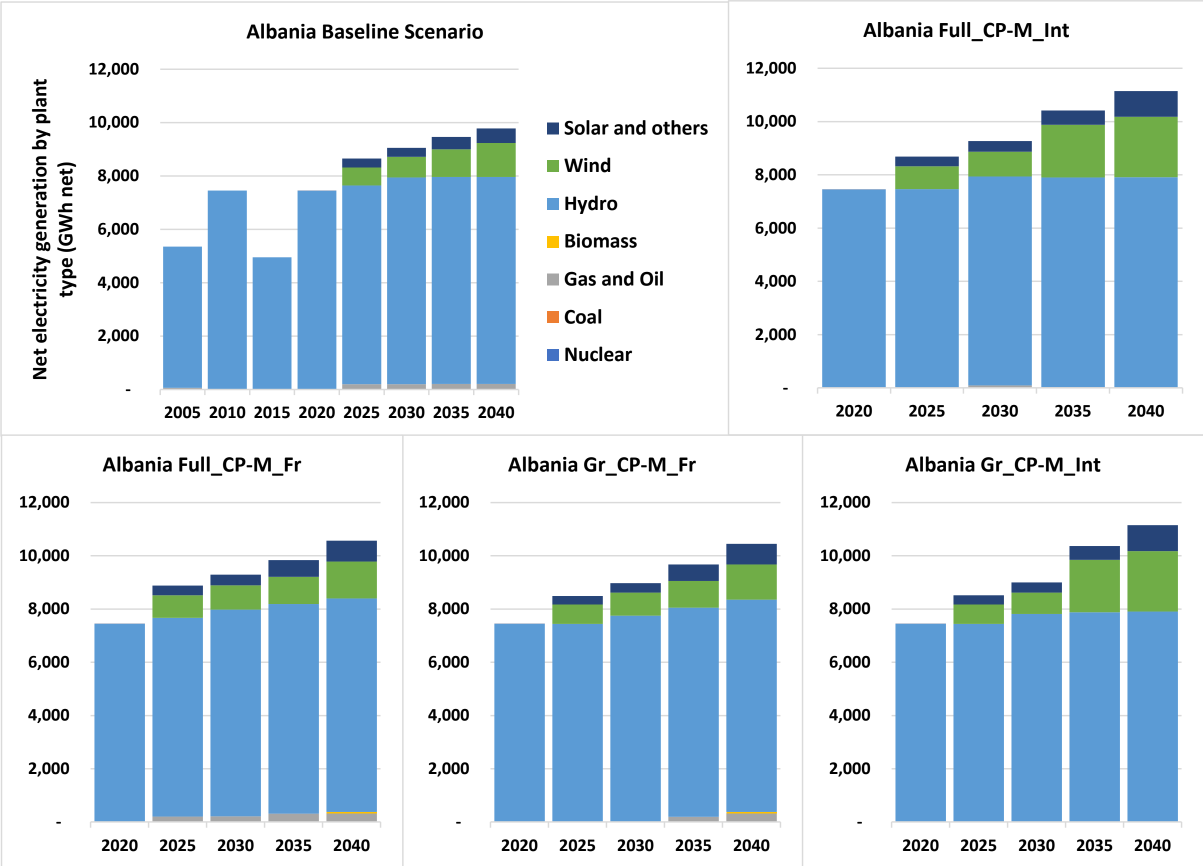


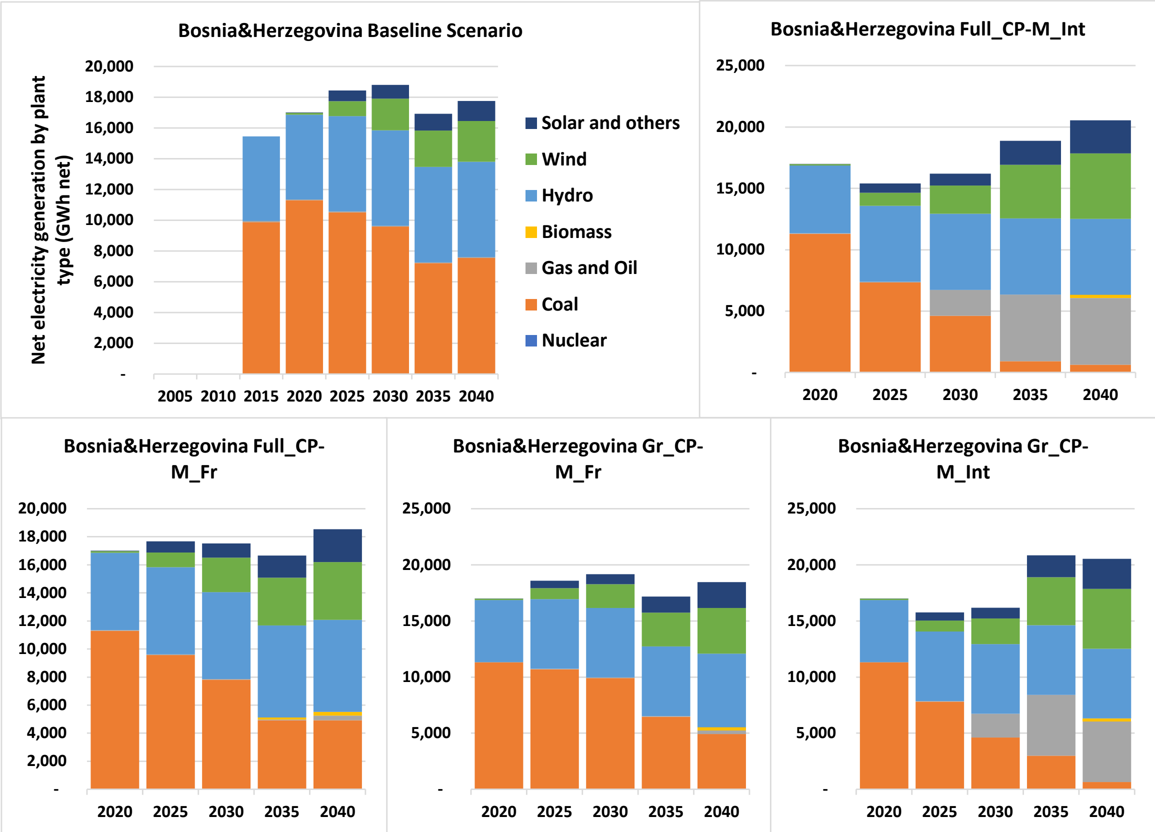
TABLE 17: CAPACITY EXPANSION IN ALBANIA ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-
Gas and Oil	97	97	97	97	97	-	-	-	-	-
Biomass	-	-	-	-	-	-	11	11	-	-
Hydro	520	520	527	540	549	-	72	79	29	20
Wind	405	453	475	419	487	258	236	247	766	699
Solar and others	274	286	327	313	327	173	345	309	476	463

6.1.2 Bosnia and Herzegovina

Bosnia and Herzegovina covers its electricity needs primarily from lignite and secondarily from hydro. Under the Baseline scenario, despite lignite dependency, outgoing capacity of opted-out plants puts a strain on exports, which tend to decrease in the future. Variable RES increase at a slow pace, meeting just 22% of total power generation by 2040, which is substantially below potential. Hydropower remains stable and covers approximately 1/3 of demand. Gas is almost inexistent; and when looking at operating capacities and planned investment for both gas and variable RES, projections reveal these do not suffice to cover electricity demand in the future.

Figure 9: Power generation outlook for Bosnia and Herzegovina across scenarios



The introduction of carbon pricing renders coal uneconomic in Bosnia and Herzegovina, mainly from 2030 onwards. If market fragmentation persists and conditions favouring gas supply are not in place, coal remains in the system after 2030 despite high costs. The absence of gas development is an obstacle to the provision of flexibility and balancing services, which, in turn, compromises the prospect for variable RES deployment. Market integration and favourable gas supply conditions on the other hand allow for CCGT to emerge after 2030 and for wind and solar to expand significantly too. In fact, only market integration conditions make the decommissioning of coal capacities possible until 2030, irrespective of whether carbon pricing applies fully or gradually. This is because market integration allows the system to rely on gas and cross-border exchanges for balancing. However, variable RES expansion stays slightly above the Baseline trend in all scenarios until 2030, which is telling of the fact that the price of carbon is not high enough to drive lignite costs upwards and force coal out of the system. The picture changes after 2030, when market integration pushes wind and solar investment up by 75% and 30% respectively, compared to when markets are fragmented.

Table 18: Capacity expansion in Bosnia and Herzegovina across scenarios (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-

Coal	35	35	35	(928)	(928)	(478)	(484)	(484)	(275)	(275)
Gas and Oil	15	15	15	278	278	-	36	36	425	425
Biomass	11	11	11	11	11	-	53	53	51	51
Hydro	255	255	255	255	255	-	140	140	-	-
Wind	1,106	1,130	1,313	1,229	1,229	307	1,024	863	1,587	1,587
Solar & others	741	741	834	772	803	328	1,140	1,078	1,418	1,387

6.1.3 Serbia

Lignite power produces around 70% of total electricity in Serbia, the rest coming from hydropower. Despite being old and polluting, the Baseline scenario projects lignite to remain in power generation, albeit in a less dominant position, with investment poured into refurbishment in the coming years. Meanwhile, variable RES develop modestly.

The lack of gas – only one CCGT plant foreseen to be deployed in 2025 – prolongs lignite dependence in the Baseline trend and hampers the provision of flexibility and balancing, without which the uptake of variable RES is practically unattainable. Even more so, with no concrete plan for large-scale development and support, the share of variable RES represents just above 16% of total generation in 2040, implying that the sector's significant potential remains largely untapped. Hydropower is rather stable, ranging between 25%-29% of total generation until 2040, with no significant additional capacity envisaged for the said period.

Carbon pricing renders coal uneconomic mainly after 2030, since carbon prices until 2030 are not sufficiently high to compensate for low lignite costs. If combined with market integration, carbon pricing, either gradual or full, accelerates coal phase-out and pushes variable RES to meet 40% of total generation in 2040, backed by gas plant development and cross-border balancing.

In fact, market integration is critical for the decommissioning of coal capacities and can ensure fair returns to gas CCGT plants, which leads to new investment, before and after 2030. Market fragmentation on the other hand is detrimental for gas expansion, which is poor and even smaller after 2030, when compared with the Baseline trend. Furthermore, market fragmentation induces a modest increase in variable RES until 2030 compared to market integration, however, afterwards total investment is similar under both sets of conditions.

As confirmed by Serbian authorities, the projections of the scenarios for power and heat capacity development will be duly taken into consideration in the drafting of the National Energy and Climate Plan, which will define national targets for RES, energy efficiency and GHG emission reduction.

FIGURE 10: POWER GENERATION OUTLOOK FOR SERBIA ACROSS SCENARIOS

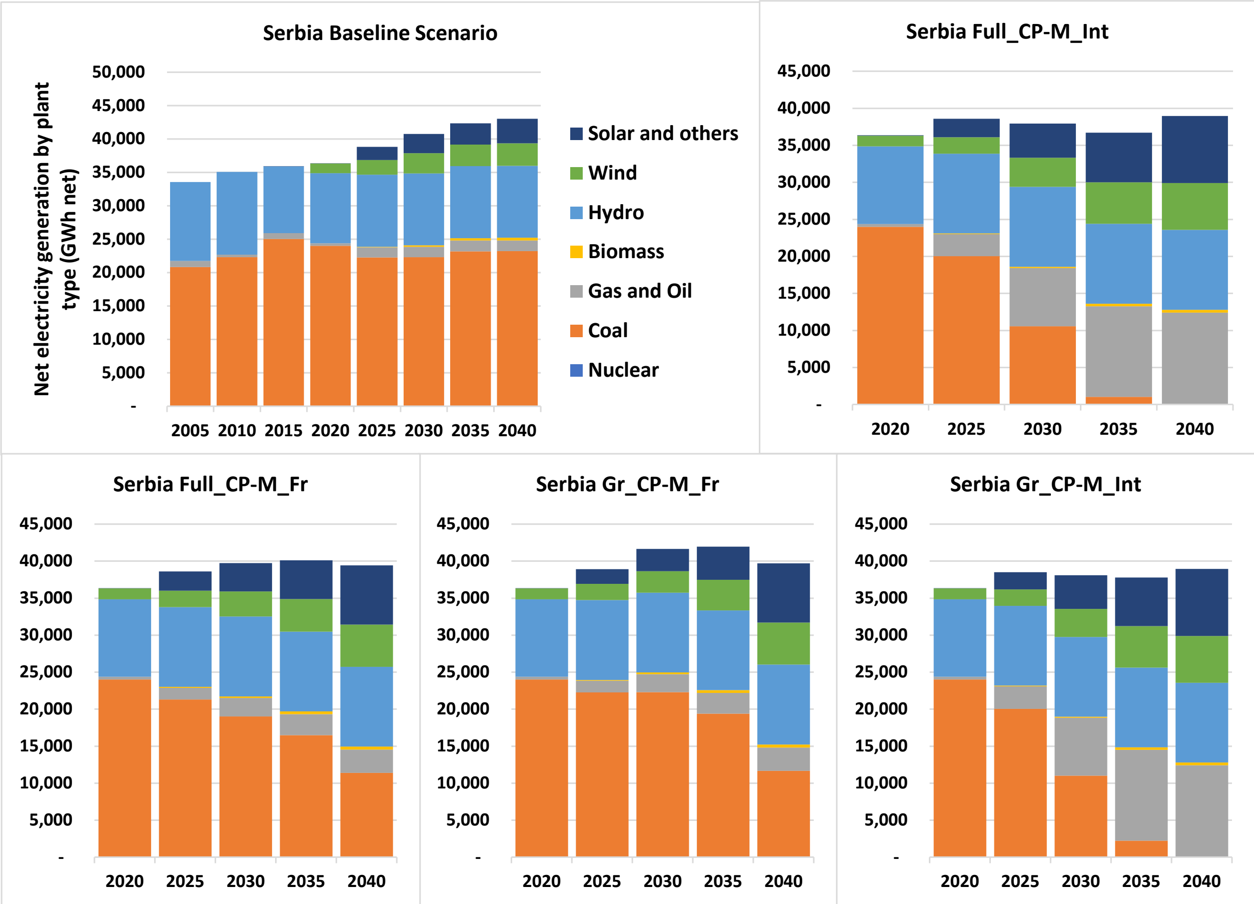


TABLE 19: CAPACITY EXPANSION IN SERBIA ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	42	42	42	(2,201)	(2,236)	-	-	-	(1,433)	(1,433)
Gas and Oil	(29)	97	112	939	953	371	167	152	983	1,000
Biomass	102	81	81	61	73	13	35	35	48	36
Hydro	174	174	174	174	174	-	-	-	-	-
Wind	1,725	1,671	1,888	2,075	2,138	150	1,267	1,050	1,152	1,089
Solar & others	2,167	2,271	2,896	3,456	3,502	620	3,813	3,188	3,436	3,390

6.1.4 Montenegro

Lignite and hydropower continue to make up the largest part of Montenegro's power generation under Baseline conditions. Further expansion of hydro is pursued with the commissioning of 172 MW Komarnica HPP and refurbishment of existing ones Piva and Perucica HPP. The one and only lignite power plant is old but gets refurbished in the period 2021-2025, so that it remains in operation due to system reserve requirements under both Baseline and market fragmentation conditions. This involves unnecessary emissions. More so, relying on an inflexible plant that is poorly set to provide the necessary balancing and reserves compromises the country's considerable potential to develop variable RES. In fact, the Baseline scenario foresees variable RES comprising 32% of total power generation in 2040.

Applying carbon pricing under market integration drives wind and solar development particularly after 2030. This is because market integration enables cross-border balancing and local storage deployment. As a result, variable RES contribute up to 60% of total generation in 2040, permitting Montenegro to decommission the Pljevlja lignite plant and decarbonise its system as soon as 2025. Market integration thus cancels the need for gas plant development, drives further the expansion of variable RES thanks to cross-border balancing and allows for a complete emissions abatement. Conversely, the lignite plant stays in place due to system reserve requirements, under both the baseline and market fragmentation conditions.

FIGURE 11: POWER GENERATION OUTLOOK FOR MONTENEGRO ACROSS SCENARIOS

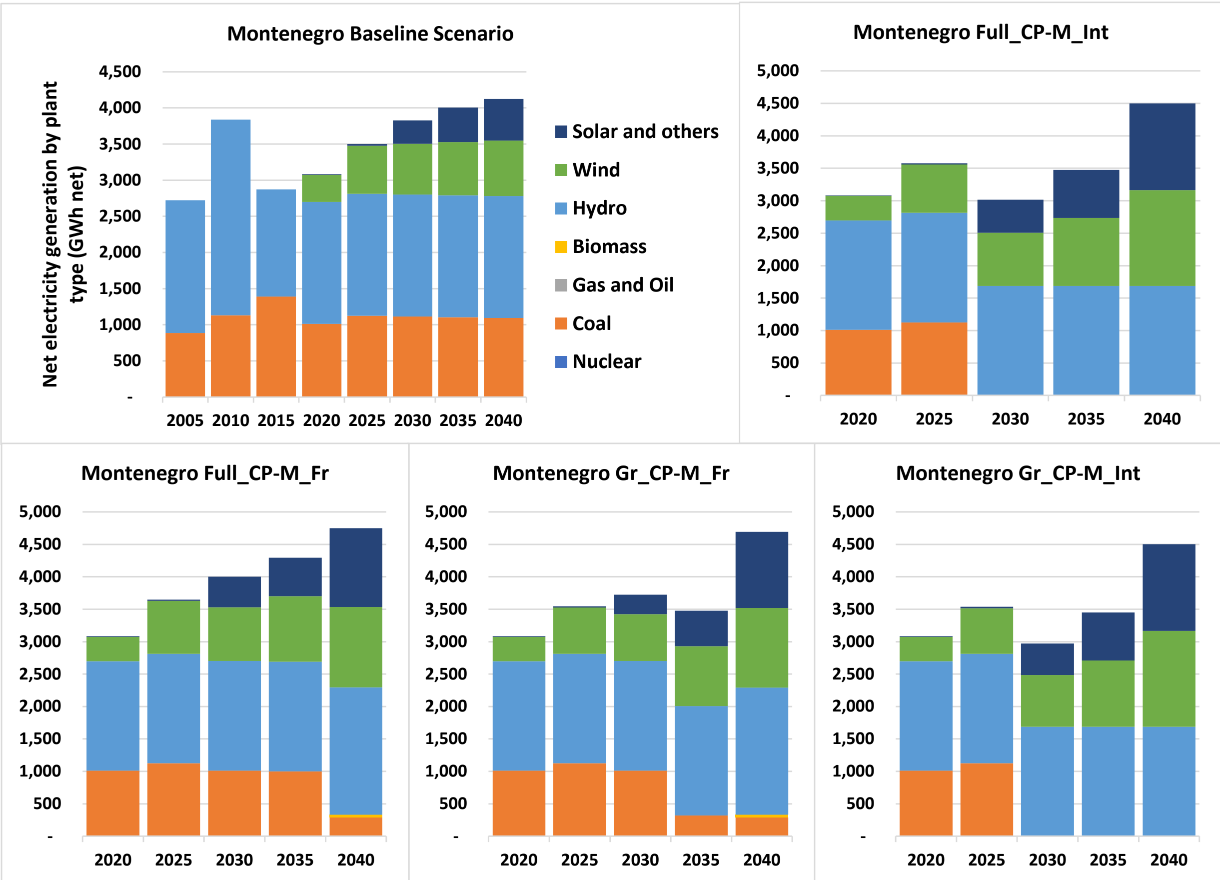


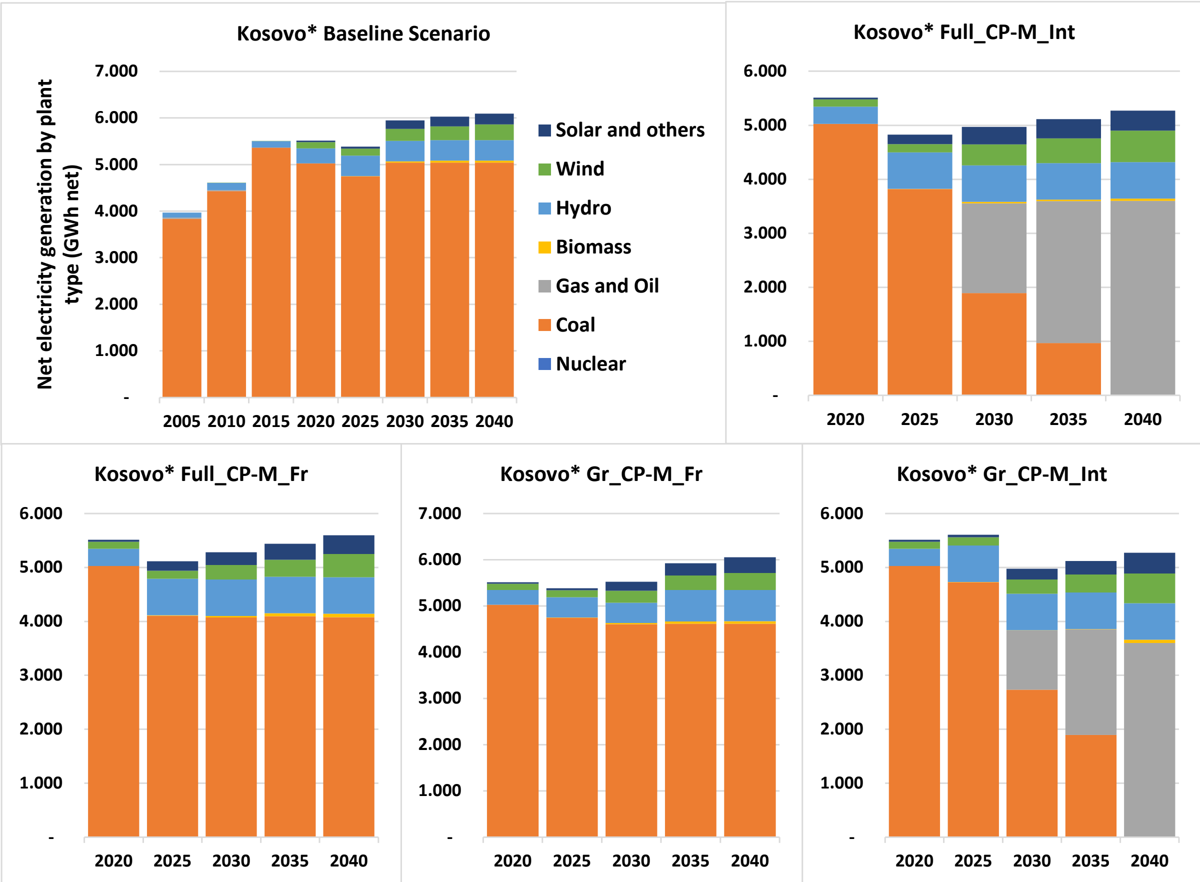
TABLE 20: CAPACITY EXPANSION IN MONTENEGRO ACROSS SCENARIOS (IN MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	(225)	(225)	-	-	-	-	-
Gas and Oil	-	-	-	-	-	-	-	-	-	-
Biomass	10	10	10	10	10	-	11	11	-	-
Hydro	24	24	24	24	24	-	118	118	-	-
Wind	338	349	403	388	399	35	261	215	353	342
Solar and others	263	244	383	394	413	204	710	605	691	673

6.1.5 Kosovo*

Power generation remains fully dependent on lignite throughout the projection period under the Baseline scenario. The prospects of variable RES development are poor – just below 10% in 2040 – while the lack of gas infrastructure and proper gas market hinder gas power investment. Adding to that the insufficient capacity (operating and reserve) and low prospects for new investment, Kosovo*'s power system becomes highly inelastic to carbon pricing.

FIGURE 12: POWER GENERATION OUTLOOK FOR KOSOVO* ACROSS SCENARIOS



The two lignite plants currently in operation, Kosova A and Kosova B, are highly polluting and unreliable; the 50% use of capacity is telling of the fact that they are inefficient and operate at partial load. A new more efficient lignite plant, Kosova e Re, meant to boost system adequacy and resilience, is foreseen to be deployed in 2028 in order to replace, partly, the two plants (the decommission of Kosova A is postponed to 2028)[34]. In the meantime, variable RES expand at a very slow pace, painting a bleak picture of the development of carbon-free sources in the country. The fragmented market conditions do not alter coal dominance and continue hindering the development of RES, despite carbon pricing applying fully or gradually.

[34] Uncertainties though remain, given that the investor withdrew from the project.

The role of market integration is thus fundamental for enabling coal phase-out, albeit this happens only after 2030 due to low lignite costs before that. The reason for maintaining a small share of free allowances in 2040 reflects the persisting difficulty of Kosovo* to deploy domestic renewables and storage facilities. Market integration together with carbon pricing on the contrary accelerate investment in variable RES and so wind and solar capacities increase. In addition, market integration brings about investment in CCGT, which makes possible the decommissioning of part of coal power capacities. Impressive as it may be, coal capacities are eliminated under market integration only after 2035. The remarkable difference in the impacts of market integration and market fragmentation holds true irrespective of the pace of applying carbon pricing.

TABLE 21: CAPACITY EXPANSION IN KOSOVO* ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	(87)	(148)	(222)	(537)	(537)	-	-	-	(610)	(610)
Gas and Oil	-	-	-	149	222	-	-	-	455	379
Biomass	12	8	8	2	8	-	8	10	14	5
Hydro	89	89	156	156	156	-	67	-	-	-
Wind	135	137	143	139	206	43	55	85	154	101
Solar and others	167	176	213	176	291	41	133	103	171	45

6.1.6 North Macedonia

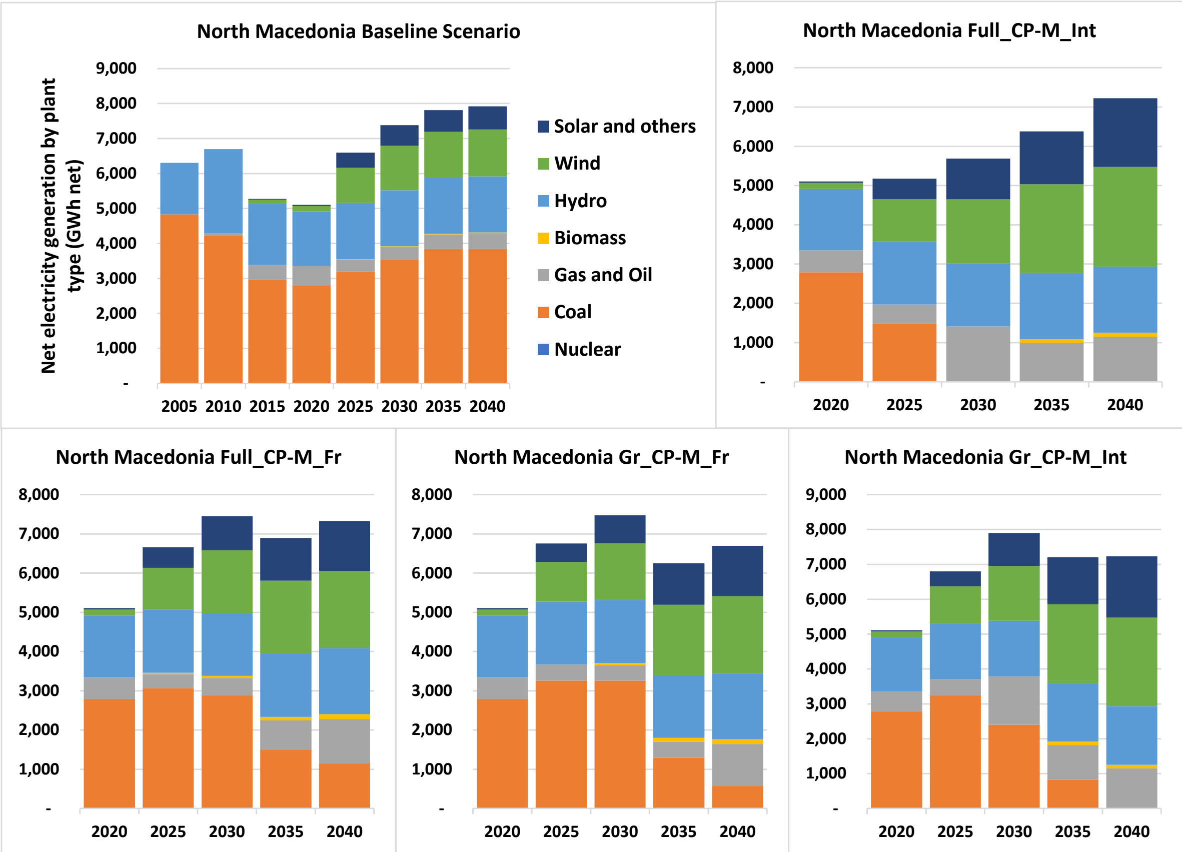
Under the Baseline scenario, power generation continues to rely on lignite and hydropower. Despite being old, lignite plants maintain a high share in total generation until 2040. Phase-out is foreseen for some units (Bitola 1-3, Oslomej 1) and refurbishment is pursued for others (Bitola 4). Gas power plant investment, completed recently, drives an increase in the share of gas in power generation from 2020 onwards. Still, it is not clear whether gas power development can be an alternative, given the current infrastructure and gas market conditions.

The Baseline scenario assumes that one CCGT plant of 220 MW is developed (TETO Zajcev Ridare) in 2025 as well as two (2) gas units of 205 MW and 85 MW in 2025 and 2030 respectively. Variable RES are projected to cover 25% of total power generation in 2040, which falls behind North Macedonia's actual potential. This is attributed to the fact that, under Baseline conditions, the power market is rather isolated and uncertainty around concrete support schemes discourages further investment in RES.

Therefore, the mix of power technologies under the Baseline scenario remains unchanged and heavy reliance on lignite persists. The contribution of gas-based generation is small overall and hydro remains stable, while wind and solar develops notably compared to today, yet not to the extent that would allow tapping the country's potential.

Projections reveal a marked difference in the structure of power capacities between market integration *vs.* market fragmentation and the Baseline conditions. Whether full or gradual, carbon pricing drives the expansion of variable RES capacities – slightly more in the latter case. Still, the decisive factor for RES growth and the pace of decarbonising the power system is market integration.

FIGURE 13: POWER GENERATION OUTLOOK FOR NORTH MACEDONIA ACROSS SCENARIOS



Carbon pricing as such induces a coal phase-out process, which develops at different speeds. Projections show that market integration in tandem with full carbon pricing can hasten coal phase-out. In those conditions, variable RES dominate generation, backed by gas-firing power and cross-border balancing. Carbon pricing drives an increase in the power capacities of variable RES, compared to the baseline, and the full carbon pricing cases induce slightly higher investment in RES compared to the gradual carbon pricing. Indicatively, under market integration conditions, RES are projected to cover 75% of total generation from 2030 already, of which 60% is variable RES; the total RES share climbs to 84% in 2040, with an impressive 75% share provided by variable RES. The projections show investment in new CCGTs in the period before 2030 and not after. If, however, markets remain fragmented and carbon pricing applies gradually, decarbonisation is delayed considerably.

TABLE 22: CAPACITY EXPANSION IN NORTH MACEDONIA ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	(86)	(238)	(281)	(300)	(524)	-	-	-	(326)	(212)

Gas and Oil	314	401	438	44	189	1	-	-	-	-
Biomass	12	22	22	8	8	0	19	20	29	29
Hydro	58	58	58	58	58	-	30	30	30	30
Wind	436	501	557	548	572	26	198	141	366	342
Solar and others	456	560	685	748	824	60	460	328	655	579

6.1.7 Ukraine

Under the Baseline scenario, nuclear power continues to be the main source of generation, covering close to 50% across the projection period, while prospects for investment towards new nuclear capacity or refurbishment are not envisaged. Maintaining the level of nuclear production, as assumed in all scenarios, is of great importance for limiting emissions. The coal fleet, which today meets approximately 1/3 of total generation, is very old and inefficient and so, a significant part of it is already subject to the Large Combustion Plants Directive and has entered a limited operating regime. For the future, the Baseline scenario foresees retirement of half of the coal capacities, with the replacement strategy of those capacities remaining unclear.

For variable RES, the Baseline scenario projects that they develop aggressively, with solar and wind operating capacities reaching close to 14 GW and 9 GW in 2040 – from today's 487 MW and 327 MW respectively. Combining variable RES with hydro – which also expand, yet moderately – and nuclear, then carbon-free power is projected to cover an impressive 80% of total generation in Ukraine by 2040. This is telling of the ample resources Ukraine is endowed with, which may allow its system to adapt flexibly to carbon pricing.

Nonetheless, the poor availability of balancing resources and reserves and lack of adequate storage constitutes a barrier to fully tapping the potential of variable RES. A combination of new large hydro and peak devices covers the balancing needs. In alternative policy scenarios, the system's balancing needs increase due to higher penetration of RES. Therefore, battery storage facilities and new CCGTs along with large hydro and peak devices, are used to balance the variable generation of RES. The modelling takes into account the balancing needs of the system and considers that a minimum level of ancillary services should be met by a pool of resources.

While old gas plants are decommissioned after 2020, investment possibilities to increase further the efficiency of gas firing generation remain unclear. Therefore, the limited possibilities for expanding gas-based generation clearly restrict the system's flexibility in all scenarios. Full coal phase-out is also difficult due to gas limitations.

Carbon pricing induces a larger and faster growth of wind and solar capacities compared to the Baseline trend. This growth is similar under gradual and full application of carbon pricing; the only difference is full carbon pricing acts as a catalyst for wind power investment to occur earlier in time. Unlike the rest of the EnC, market conditions have no major impact on investment in Ukraine. Ukraine has special interconnections with EU countries, including Poland, Romania, and Slovakia mainly. Market integration means in this case higher use of interconnections and reinforcements but not market coupling. Under market integration conditions, solar power investment develops in the period until 2030 slightly more than under market fragmentation thanks to higher flexibility resources. The scenarios include investment in hydropower at levels slightly above Baseline trends. A sensitivity analysis has shown that improved gas supply conditions could relax limitations of flexibility.

FIGURE 14: POWER GENERATION OUTLOOK FOR UKRAINE ACROSS SCENARIOS

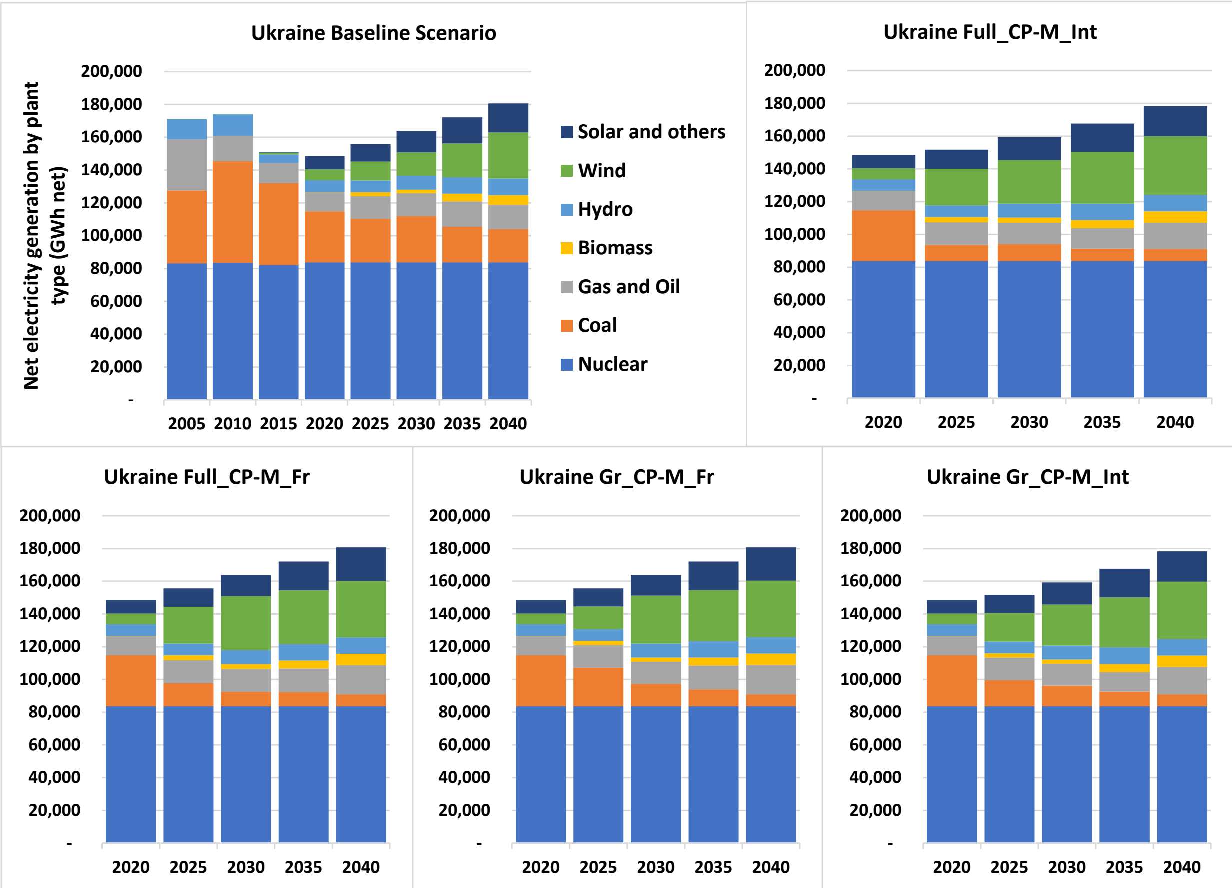


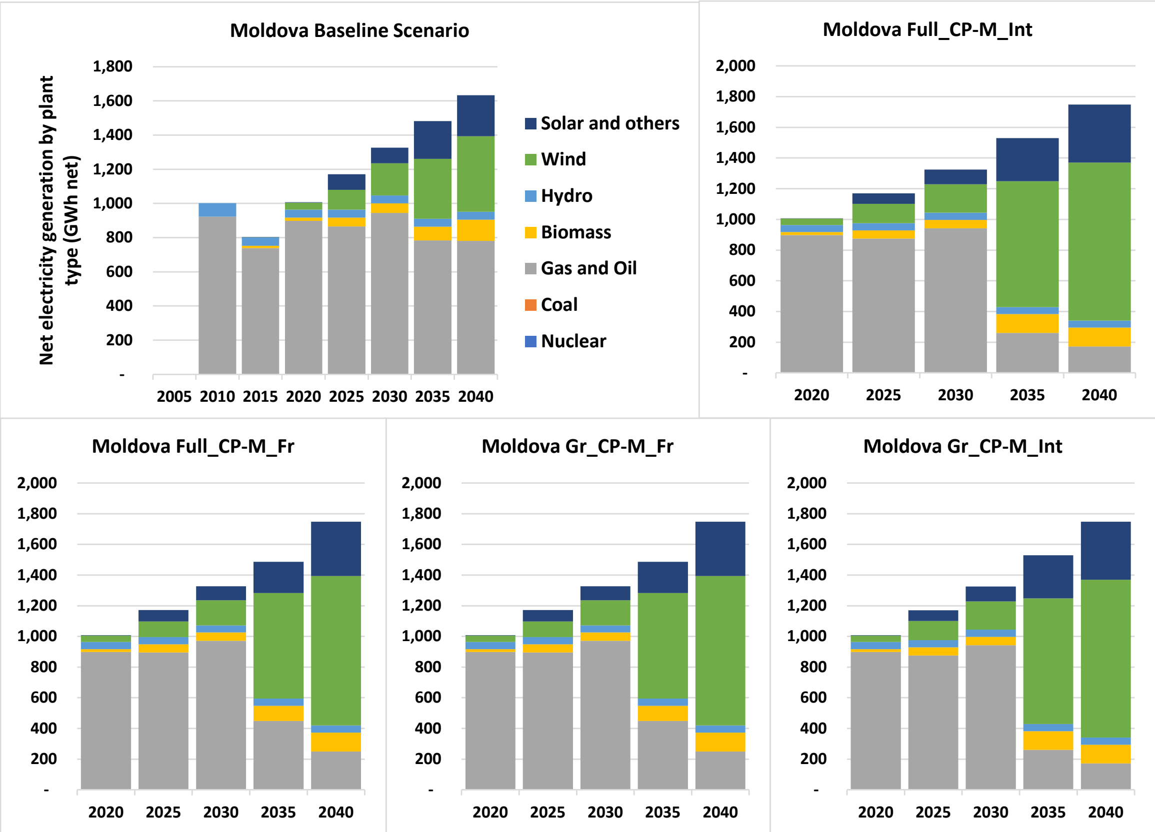
TABLE 23: CAPACITY EXPANSION IN UKRAINE ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	(5,557)	(6,106)	(6,106)	(6,106)	(6,106)	(4,978)	(5,724)	(5,724)	(5,667)	(5,628)
Gas and Oil	(5,494)	(5,530)	(5,437)	(5,583)	(5,583)	(3,522)	(2,577)	(2,782)	(2,490)	(2,497)
Biomass	454	515	624	514	624	768	865	751	872	757
Hydro	852	852	852	852	852	1,000	1,000	1,000	1,000	1,000
Wind	4,221	8,970	10,120	7,664	8,104	4,367	1,680	501	3,150	2,963
Solar and others	9,610	9,295	9,493	9,998	10,385	3,668	5,968	5,890	3,954	3,416

6.1.8 Moldova

The Moldovan power system is weak due to physical constraints and very high dependence on imported fossils. The Baseline scenario projects that until 2030 power generation continues to be met for most part via imported natural gas and a minor contribution of biomass, hydro and variable RES. Coal is not used in power generation, but the existing coal-fired units serve for reserves, and are likely to be decommissioned after 2030. Electricity generation comes from CHP gas-fired plants, providing both electricity and heat for district heating. The CHP plants are heavily constrained for electricity generation, dispatched primarily to meet heat load. Between 2030 and 2040, the deployment of variable RES – and particularly wind – is envisaged, reaching close to 42% of total power generation. This is however not that significant, considering Moldova's huge reliance on fossil-based imports. If hydropower and biomass are added up, carbon-free power is projected to account for 52% of total generation.

FIGURE 15: POWER GENERATION OUTLOOK FOR MOLDOVA ACROSS SCENARIOS (MW)



The rest of the scenarios envisage the continuation of massive imports, as in the Baseline, allowing the recovery of energy and ancillary services adequately. Under such conditions, market integration or fragmentation has no applicability. Driven by carbon pricing, wind and solar power expand considerably after 2030 and gas is used mainly to support variable RES providing them with balancing services. An important issue for system planning and economics that requires further investigation is whether the unused coal power plants will remain in reserve also beyond 2030. If decommissioned, then power reserves will diminish considerably. The scenarios have assumed that open cycle gas peaking plants maintain reserves to some extent. Hence, it is worth examining further whether a strategy based exclusively on imports for balancing variable RES would be acceptable from a security perspective.

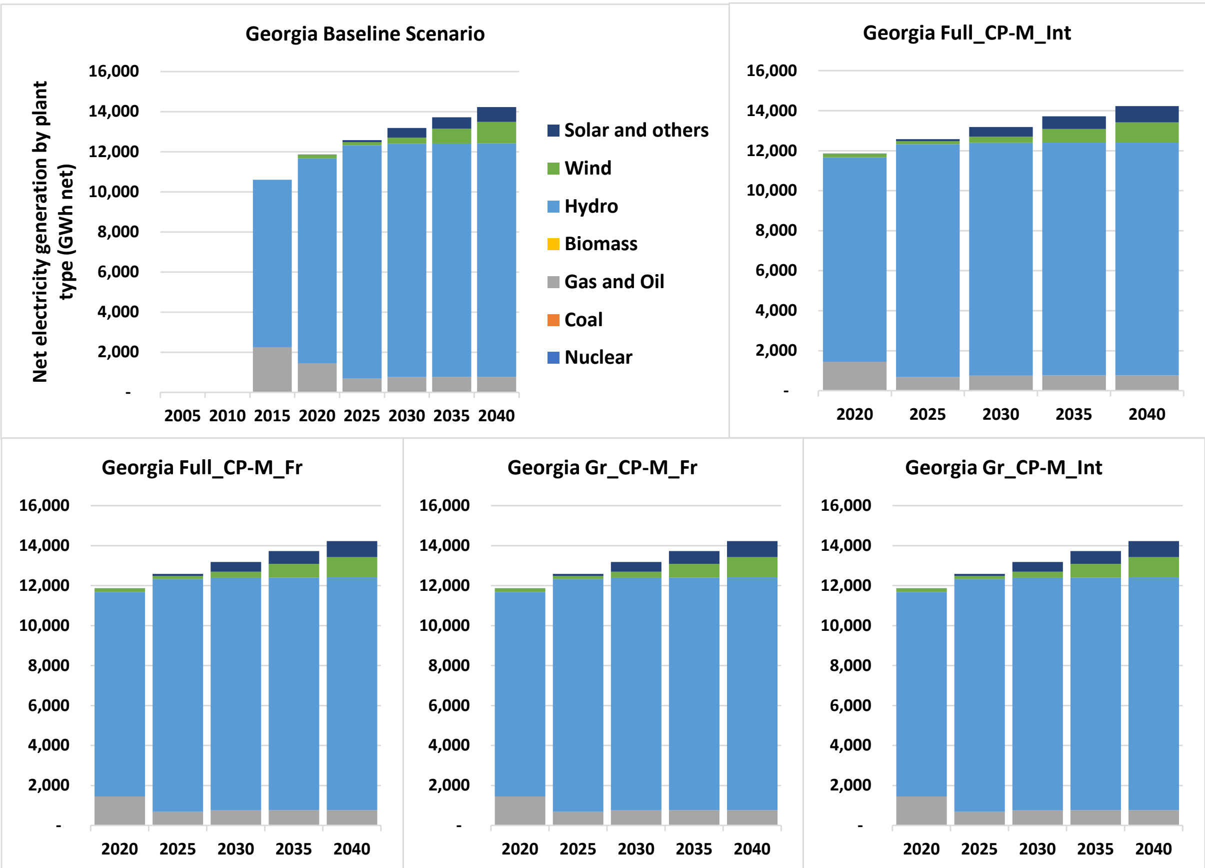
TABLE 24: CAPACITY EXPANSION IN MOLDOVA ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	(1,600)	(1,600)	(1,600)	(1,600)	(1,600)
Gas and Oil	(14)	(14)	(14)	(14)	(14)	(400)	(507)	(507)	(698)	(698)
Biomass	16	16	16	16	16	19	19	19	19	19
Hydro	0	0	0	0	0	-	-	-	-	-
Wind	104	90	90	102	102	133	424	424	441	441
Solar & others	74	73	73	78	78	121	215	215	230	230

6.1.9 Georgia

The Georgian power system is largely based on carbon-free power, which represents close to 80% of total generation. Under Baseline projections carbon-free power climbs to almost 95% in 2040, and hydropower, that provides the bulk of it, expands further. Variable RES contributes 6% in 2030 and close to 13% in 2040 from 0% today. This share does not reflect Georgia's potential.

FIGURE 16: POWER GENERATION OUTLOOK FOR GEORGIA ACROSS SCENARIOS



Nonetheless, Georgia represents a green power system with ample flexibility and balancing resources, thus fully resilient to carbon pricing. The Baseline scenario projects gas, which covers approximately 12% of power generation today, to drop by almost half from 2025 onwards and keep the same share until 2040. This is attributed to the decommissioning of old gas units and the lack of replacement. Further developing variable RES is possible under the other scenarios, compared with the Baseline, being a matter of economics mainly. Essentially, projections show no impacts of carbon pricing and system resilience is solid. More so, market integration and fragmentation assumptions are not applicable, as the system has no direct connections with Europe.

TABLE 25: CAPACITY EXPANSION IN GEORGIA ACROSS SCENARIOS (MW)

	2015-2030					2030-2040				
	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int	BSL	Gr_CP-M_Fr	Full_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Int
Nuclear	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-
Gas and Oil	231	231	231	231	231	(511)	(511)	(511)	(511)	(511)
Biomass	-	-	-	-	-	-	-	-	-	-
Hydro	860	860	860	860	860	-	-	-	-	-
Wind	82	82	82	82	82	220	202	202	202	202
Solar and others	293	293	293	293	293	158	199	199	199	199

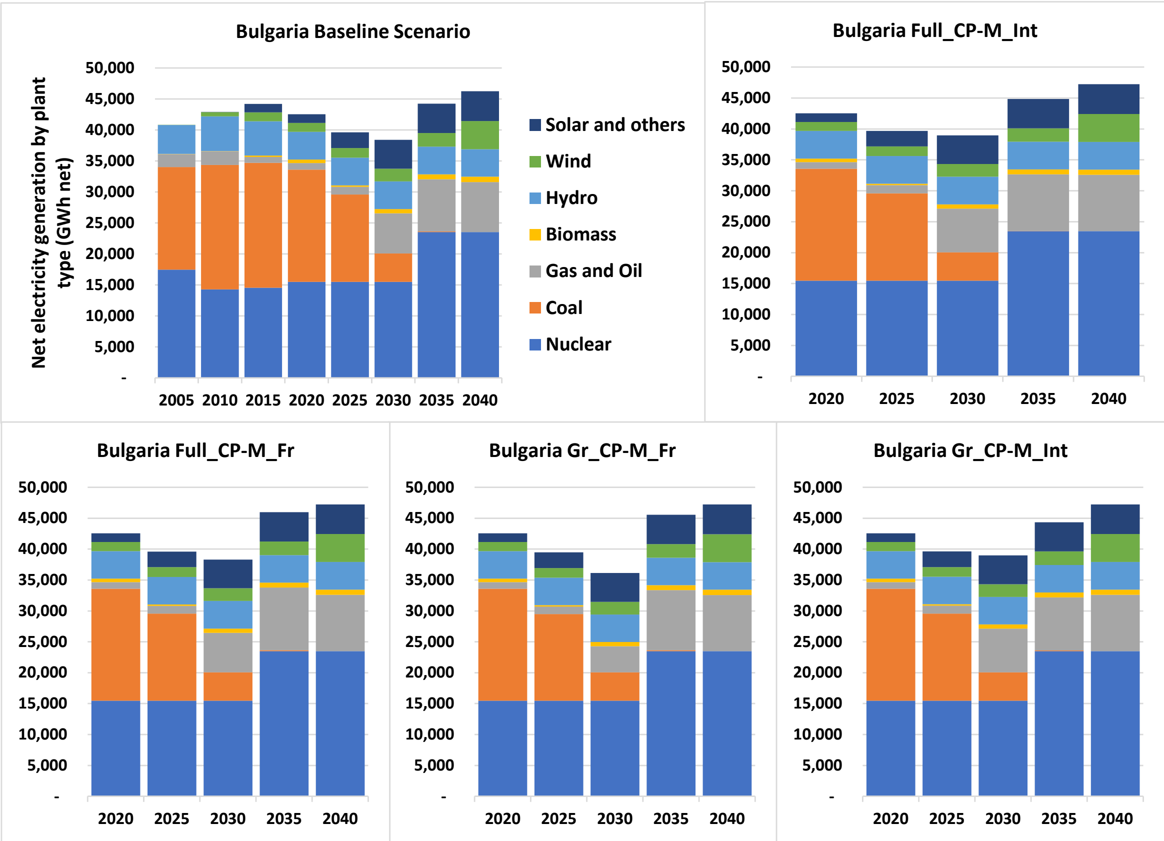
6.1.10 Bulgaria

Power generation in Bulgaria relies equally on solid fuels and nuclear. Hydro contributes to balancing and peak generation, gas and variable RES play a minor role in the system. Full EU ETS applies in all scenarios with the Baseline scenario projecting that the soaring EU ETS prices driven by the application of the MSR will adversely affect lignite competitiveness. The share of lignite in power generation is therefore projected to fall at a fast pace, and the aged lignite fleet to be fully decommissioned until 2040.

The development of additional gas capacity occurs post 2025; however, the energy efficiency of the gas fleet is poor compared to modern large-scale CCGT. This is why the capacity gap created by the decommissioning of inefficient gas plants in 2030 and 2040 is filled by the deployment of two (2) CCGT plants (790 MW and 844 MW) in the respective years. The pace of developing variable RES is slow in accordance with the Bulgarian NECP.

In the Baseline projection, variable RES are not likely to exceed 20% of total generation by 2040, which is triple from current levels, yet much below Bulgaria’s potential. Nuclear maintains a central role in the power system and is further reinforced post-2030, meeting half of total generation in 2040. Market integration vs. fragmentation is found not to affect the power generation structure significantly and overall few differences of power capacity structures are implied, resulting from the different conditions across scenarios.

FIGURE 17: POWER GENERATION OUTLOOK FOR BULGARIA ACROSS SCENARIOS

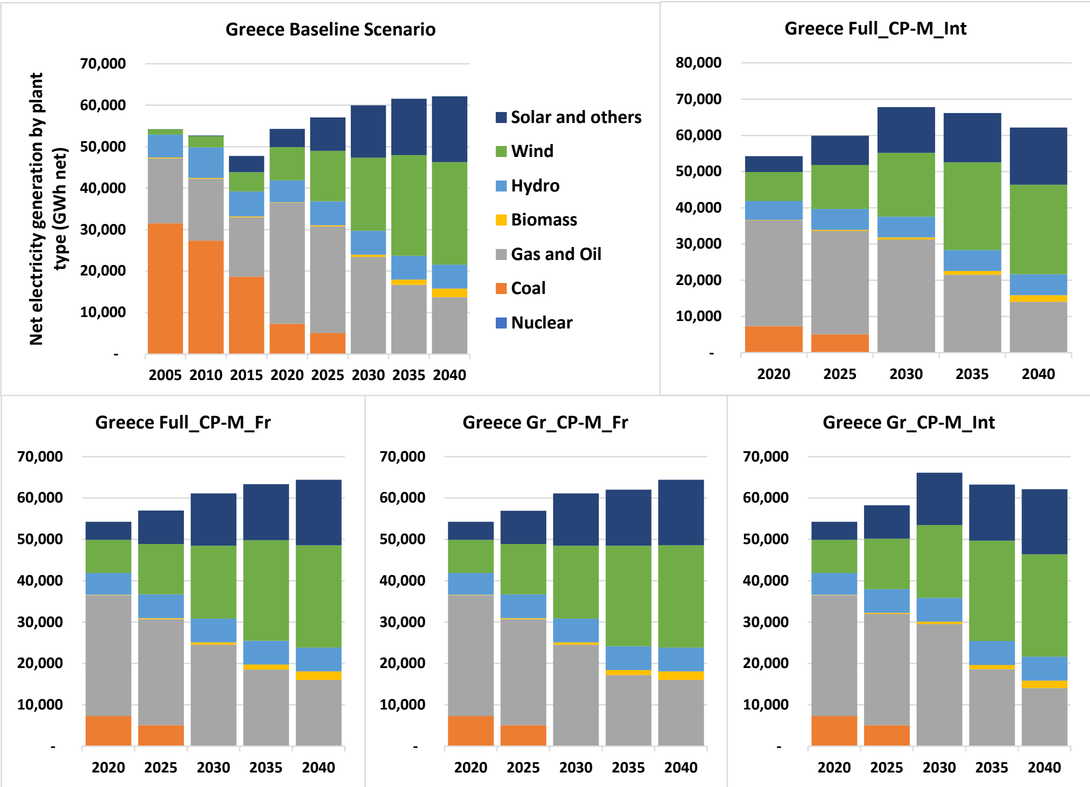


6.1.11 Greece

The Baseline scenario reflects the country's NECP regarding lignite phase-out as early as 2023, with the exception of a large new lignite power plant that will start in 2022 and stop operating at the end of 2028. Variable RES develop exponentially under Baseline conditions, reaching 65% of total generation by 2040. Variable RES and hydro may thus generate close to 80% of total electricity in Greece by 2040. Four (4) large-scale new CCGT plans will be added starting 2020 then 2025 and 2030; these will partly replace lignite and balance variable RES. Like with Bulgaria and Romania, full EU ETS applies in all scenarios and market integration vs. fragmentation concerns the connections with non-EU countries.

The significant increase in EU ETS carbon prices over the recent years has already led to a re-ordering of the merit-order dispatching in favour of gas and to the detriment of lignite. Thus, the dominance of lignite in generation is drifting away and the replacement of lignite by gas in the merit-order dispatching is already happening. An increase in gas-based generation is projected, albeit only before 2030. The market integration conditions induce higher exports of gas-based generation and balancing, compared to market fragmentation. The difference is more pronounced until 2030.

FIGURE 18: POWER GENERATION OUTLOOK FOR GREECE ACROSS SCENARIOS

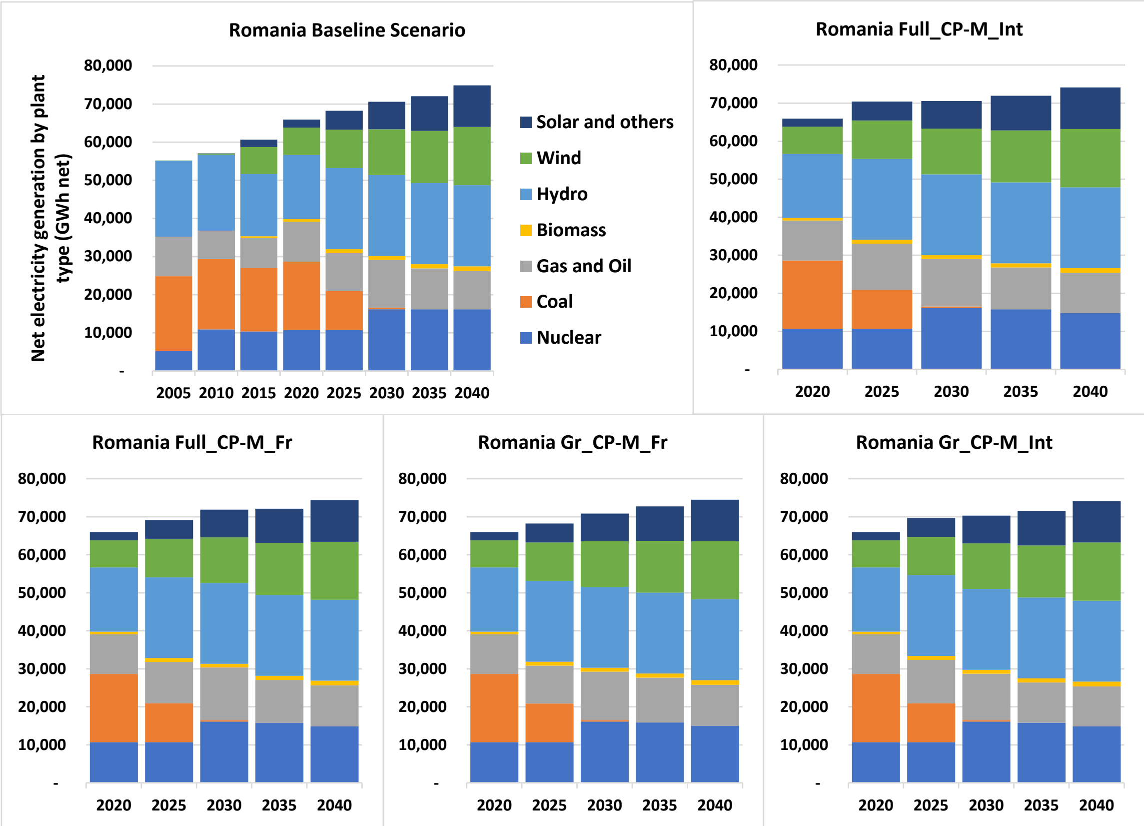


6.1.12 Romania

Romania currently relies on hydro, nuclear and solids, while the gas fleet undergoes modernization with new CCGT plants being deployed in the period 2020-2030 under Baseline conditions. Full EU ETS applies in all scenarios and market integration vs. fragmentation concerns Romania's connections with non-EU countries.

The basic trend across scenarios in Romania is a fast coal phase-out, nuclear capacity added by 2030, complemented by significant development of wind and solar and moderate expansion of gas-firing capacity. No visible impacts of the various conditions described in the scenarios are spotted on generation structure.

FIGURE 19: POWER GENERATION OUTLOOK FOR ROMANIA IN VARIOUS SCENARIOS



6.1.13 Summary of regional trends in power generation

Historically, solid fossil fuels have accounted for the lion's share of power generation in the EnC region. The study argues that continuing down this path, as the Baseline scenario suggests, is not sustainable. Growing diseconomies of scale and reluctance to invest in refurbishment are expected to undermine severely the competitiveness of solids-firing generation and jeopardise security of supply. Moreover, under Baseline conditions the potential of variable RES remains largely untapped. Despite being the cheapest option, wind and solar are not getting the support they need, which further delays the low-carbon transition. Likewise, the Baseline scenario prevents CPs from leveraging natural gas as a means to moving away from solids and reducing emissions. Gas can replace coal in power generation and at the same time provide the balancing services needed to address the intermittence of variable RES and facilitate their increased integration into the system. However, as gas markets remain fragmented, gas infrastructure investment is not flowing into the EnC and the CPs are effectively denied access to cheaper and more flexible gas.

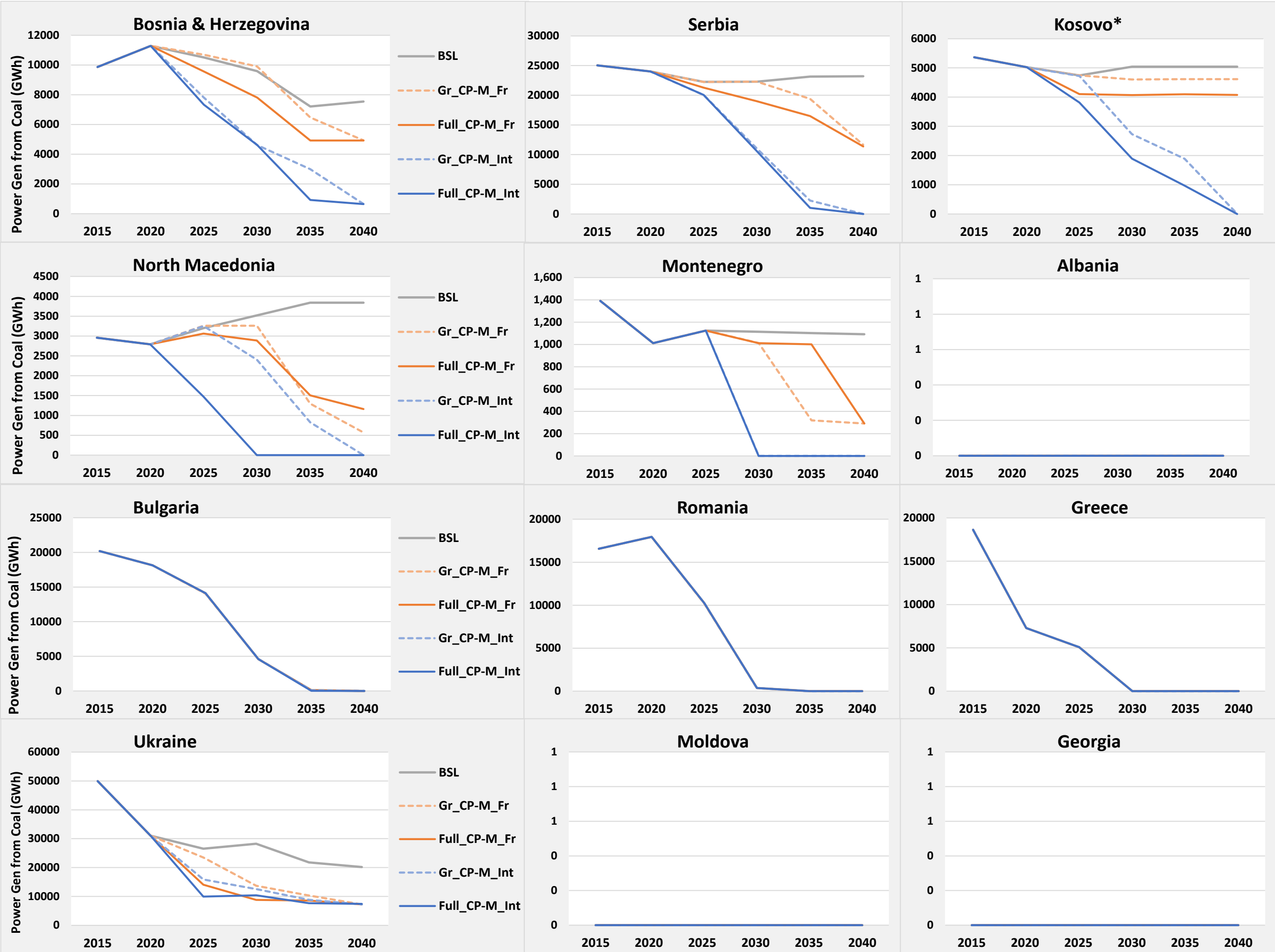
As expected, carbon pricing exerts significant pressure on solids-firing generation, and the effects are felt earlier with full carbon pricing. Key in achieving coal phase-out before or just after 2030 is market integration, irrespective of whether carbon pricing applies fully or gradually. This is because market integration amplifies cross-border flow possibilities in the EnC region, allowing CPs susceptible to carbon pricing to access low-carbon and low-cost energy generation, reserve and balancing resources, and so diversify their power mix, increase system resilience, attract restructuring investment and adjust to the introduction of carbon pricing. Actually, even a combination of market integration with gradual carbon pricing is enough to enable coal phase-out in a reasonable timeframe, where it is most difficult to do. This is the case especially for the CPs with high levels of dependence on solids, hence limited or no flexibility to carbon pricing. If on the other hand markets remain fragmented, solids are projected to stay in the system until 2040.

While carbon pricing reduces solids-based generation, gas emerges as an important complementary transition fuel. Capturing the potential of gas can nevertheless only materialize under market integration conditions, irrespective of full or gradual carbon pricing. Gas units perform the high-ramping operation needed to balance the major fluctuations of variable RES and facilitate their increased penetration in the electricity system. Evidently, other balancing resources such as hydro pumping, hydro with reservoir, demand response and batteries will have an important role to play in the future, but primarily for peak shaving or peak load shifting. These resources cannot provide ramping services directly but only reduce the system needs for ramping. Therefore, inspite of the dropping costs of batteries, gas units are more competitive in this context, because they do not supply only ancillary services but electiricty too.

Moreover, the supply context of gas, i.e. interconnection infrastructure and gas entry points, is critical for gas uptake in the CPs, since it affects pricing and power plant investment. Market integration ensures a diverse gas supply context, which practically means the CPs have access to cheaper, more secure and flexible gas. Within a regional, integrated gas market, where investors receive the right signal regarding capital returns of new gas investment, the CPs with increased exposure to carbon pricing, like Bosnia and Herzegovina, Serbia and Kosovo*, can attract investment in infrastructure development and accelerate the substitution of solids. Less exposed CPs with higher penetration of variable RES, i.e. North Macedonia, can leverage gas as a balancing resource to accelerate the decarbonisation of their power system. Gas is projected to play a less prominent role in those CPs whose electricity systems already depend almost exclusively on RES, i.e. Albania and Georgia.

On a further note, existing or under construction gas infrastructure in the EnC could, in a future context of decarbonisation, support transporting and storing gases of small (or even zero) carbon footprint such as bio-methane, “green” hydrogen and synthetic methane, as well as blending them with natural gas, avoiding to create devalued or stranded gas infrastructure assets.

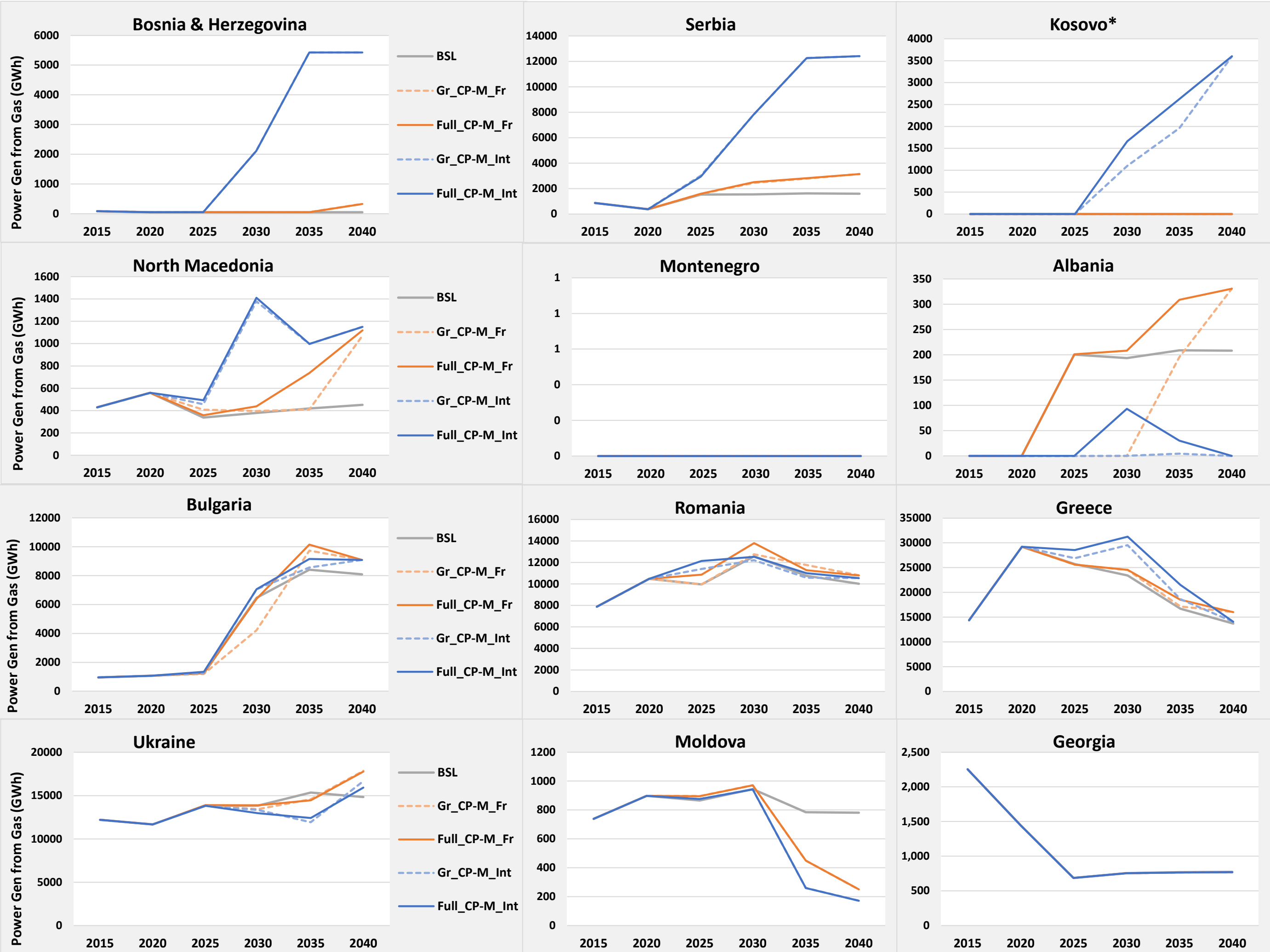
FIGURE 20: SOLIDS-BASED GENERATION IN THE ENC REGION (GWH)



Therefore, in the longer term, these gas infrastructure investments will provide the basis for the next step in environmental protection, as they will allow for the introduction of decarbonised gas once available and competitive, allowing further reductions in carbon dioxide and the impact of air pollution. Therefore, these investments will future-proof the region's energy supply.

Market fragmentation, however, prolongs uncertainty in gas pricing and supply and hampers investment in new CCGT plants that can replace old lignite plants and reduce carbon emissions. Pursuing a domestic transition approach foresees no policy harmonization across the CPs, breeding reluctance among investors to finance low-carbon facilities, as they should, in order to deliver new gas possibilities in a timely manner. This is detrimental for the CPs facing carbon lock-in, thus highly vulnerable to carbon pricing.

FIGURE 21: GAS-BASED GENERATION IN THE ENC REGION (GWH)



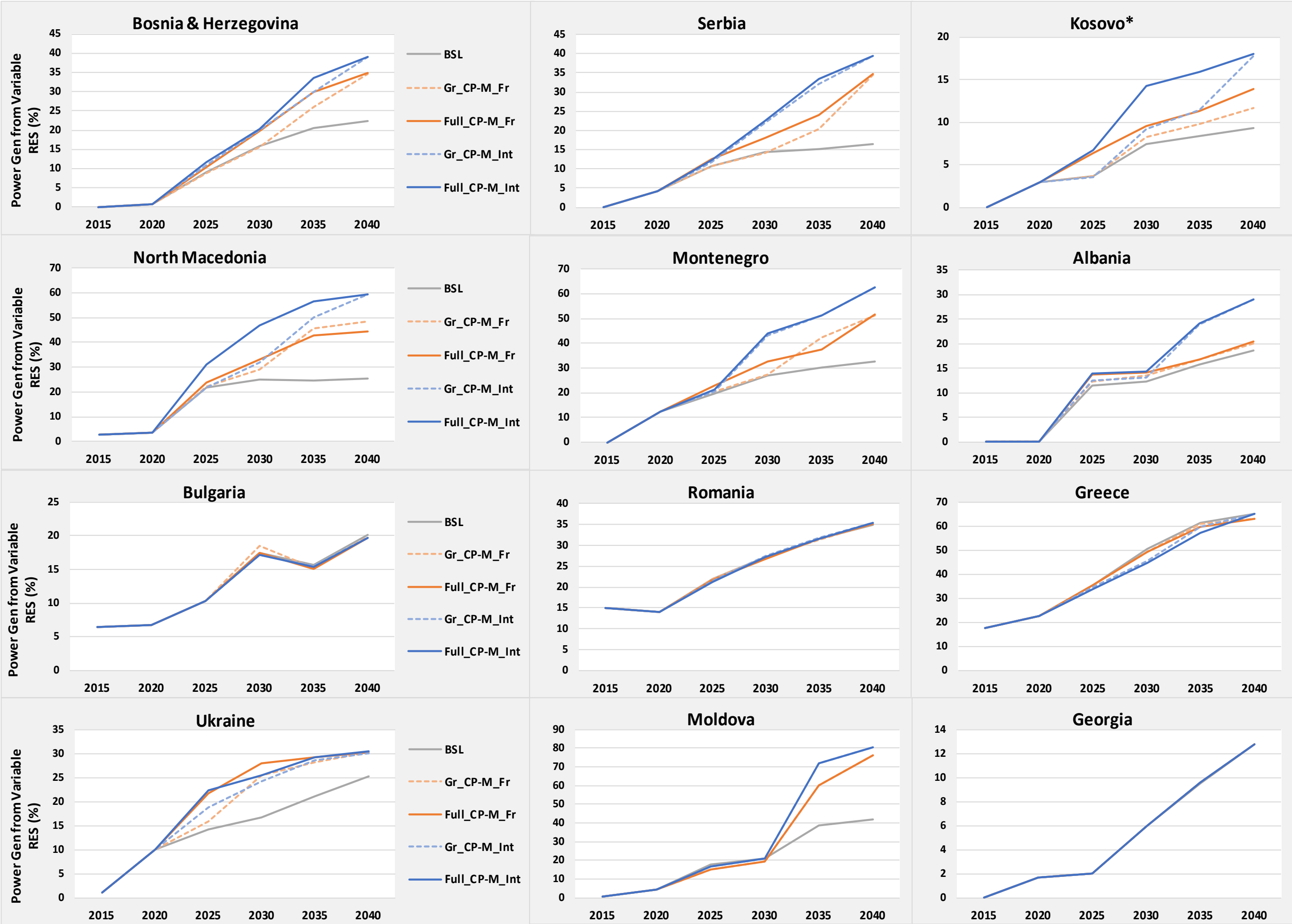
The introduction of carbon pricing also drives RES deployment. This becomes more prominent after 2030, since until then the cost of coal is low and so are carbon prices. If carbon pricing applies within an integrated market context, then the projection points to a considerable uptake of RES in total generation already in the period 2020-2030. Even if carbon pricing is gradual, still it is sufficient to induce high RES deployment until 2030 in most countries and lead to a doubling of RES shares in 2040. The increased penetration of RES leads to complete or partial decarbonisation of the power systems of Montenegro and North Macedonia and boosts power system flexibility notably in countries severely exposed to carbon pricing like Serbia and Bosnia and Herzegovina. Under market integration conditions, RES cover half of power generation in 2030 and reach a record high share of almost 70% in total power generation in 2040. In contrast, if markets remain fragmented, carbon pricing alone, and more so when applied gradually, cannot drive RES deployment until 2030. In fact, projections reveal that market fragmentation together with gradual carbon pricing hardly increase the shares of RES in 2030 compared to Baseline trends. Systems relying exclusively on RES, such as Albania and Georgia, or that combine nuclear with RES, like Ukraine and Romania, can reach full or almost full decarbonisation of power generation by 2040.

As far as variable RES are concerned, the scenarios project that these cannot integrate into the system largely due to lack of flexibility and storage (Figure 22). Normally, shares of variable RES close to 60% and above can be a challenge for systems. Hence, shares higher than 40% in most countries are not foreseen until 2040. When they do, it is thanks to market integration. Market integration facilitates cross-border sharing of balancing and storage needed to accommodate increased penetration of variable RES, without compromising system reliability. Montenegro and North Macedonia achieve 62% and 59% of variable RES shares in total generation respectively, thanks to cross-border sharing of balancing resources. In Greece, variable RES-based electricity meets 65% in 2040, facilitated by storage and gas units, while the 80% in Moldova derives from the assumption that balancing is based almost exclusively on imports. Obviously, storage is a key enabler of variable RES development; and so, market integration facilitates a larger and faster development of storage, as opposed to market fragmentation.

Solar and wind investment develops unequally in the region. Obligations deriving from key EU legislation and active policy support have driven large-scale wind and solar deployment in the EU MS and continue to do so in the projection period. Baseline and market fragmentation trends prevent the full tapping of wind and solar potential in CPs. Notably, gradual carbon pricing in a fragmented market results in a small wind fleet that develops at a slow speed. Under market integration on the other hand, wind capacity expansion is significant and intensifies after 2030, except in Greece, Romania, and Ukraine, where it happens equally fast from 2020 onwards. In fact, the differential impact of gradual *vs.* full carbon pricing on wind capacities is small, however market conditions play a much more decisive role in this regard.

Likewise, capacity expansion of solar PV that is clearly above baseline trends occurs only after 2030 in several countries and the driving force is again market integration. Until 2030, full carbon pricing pushes solar upwards under all market conditions. Reversely, if market fragmentation and gradual carbon pricing prevail, the growth pace of solar remains almost the same as in the Baseline scenario until 2030. Under market fragmentation, adapting to carbon pricing happens only domestically, without recourse to cross-border trading. The management of an emissions cap and effects on prices becomes a challenging task, and so escalating uncertainty among investors clearly impedes total uptake of solar energy.

FIGURE 22: POWER GENERATION FROM VARIABLE RES (%)

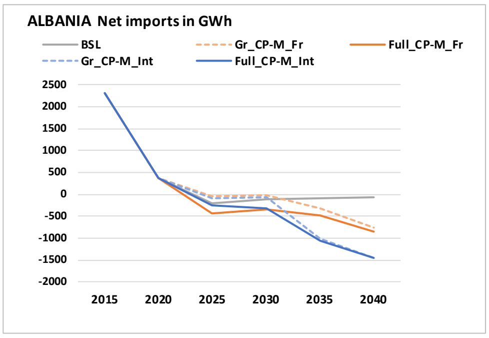


6.2 Trends in electricity trade

The persisting operation of aged, expensive and polluting thermal power plants in many CPs and the general reluctance to invest in refurbishment and new units implies that exporting non-expensive electricity based on solids will decline, reversing historical trends in the EnC. Putting a price on carbon will only hasten this trend. In fact, carbon pricing and the ensuing deployment of variable RES induce profound changes in the merit order of power plants and balancing requirements, rendering gas-based generation more valuable for energy and services compared to traditional sources. Thus, the case of generalising carbon pricing in the EnC further weakens the economics of lignite-based generation and reverses the traditional net-exporting roles of certain CPs, such as Bosnia and Herzegovina, while further increasing the import dependence of others.

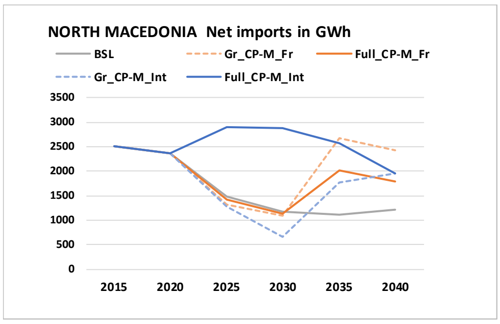
Market integration is of paramount importance because it provides carbon-intensive countries the possibility to increase their imports of balancing resources, which are necessary for RES development, and avoid prolonging the use of domestic, heavily emitting resources just for system purposes. After establishing a low-carbon profile, which occurs close to 2030, the previously carbon-intensive countries may increase exports again or decrease imports, thanks to market integration. Market fragmentation on the other hand hinders RES development and maintains unnecessary carbon costs. The traditional power fleet remains in operation but becomes uneconomic in the future, causing capacity adequacy to erode and carbon costs to rise. Overall, these developments bring electricity exports down. The contrast of projections regarding market integration *vs.* fragmentation is similar in both gradual and full application of carbon pricing.

FIGURE 23: NET IMPORTS OF ALBANIA IN GWH



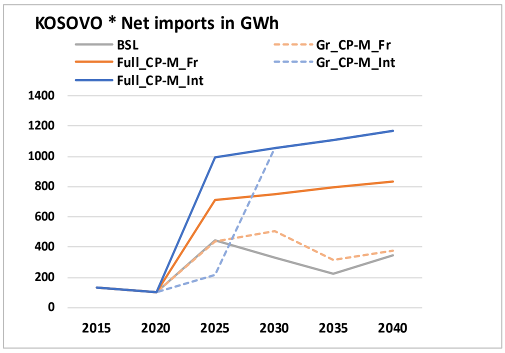
With no dependence on solids, Albania remains resilient to carbon pricing and becomes a net electricity exporter from 2020. This trend intensifies under market integration, when Albania increases its hydro-based exports, mainly towards CPs whose power generation depends heavily on solids and need carbon-free resources in order to increase their flexibility to carbon pricing.

FIGURE 24: NET IMPORTS OF N. MACEDONIA IN GWH



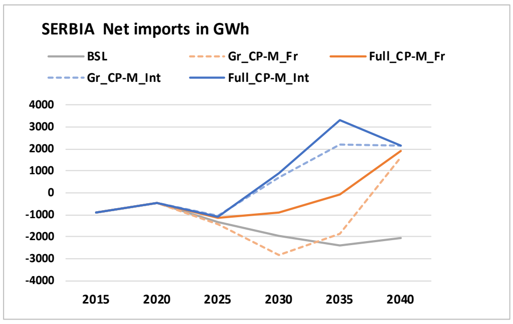
North Macedonia remains a net importer in all scenarios. Full carbon pricing makes lignite generation uncompetitive early. Under market integration, imports increase significantly until 2030 to support the development of variable RES and diversify the power mix. After helping the country develop a low-carbon profile, imports start to drop post- 2030.

FIGURE 25: NET IMPORTS OF KOSOVO* IN GWH



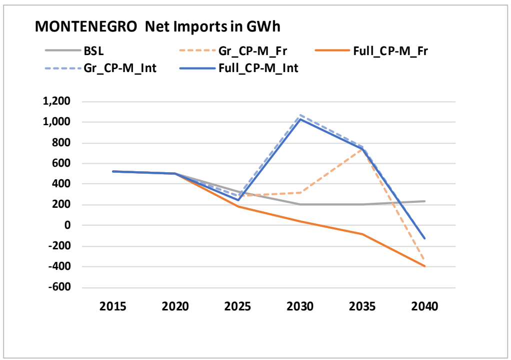
Kosovo* becomes a net electricity importer in all scenarios. The lack of carbon pricing keeps imports relatively low. Carbon pricing and market integration cause an astonishing rise in imports, in support of variable RES. When combined with (gradual) carbon pricing, market fragmentation maintains solids in the power mix as well as imports, for system reliability purposes.

FIGURE 26: NET IMPORTS OF SERBIA IN GWH



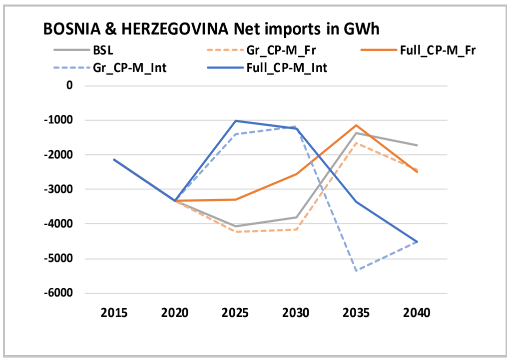
Serbia becomes a net importer close to 2030 to ease carbon-pricing effects and support variable RES; the rise is starker and occurs earlier under market integration thanks to imports of low- and carbon-free resources. Fragmentation maintains solids-based exports until 2030, despite eroding trends and rise in costs.

FIGURE 27: NET IMPORTS OF MONTENEGRO IN GWH



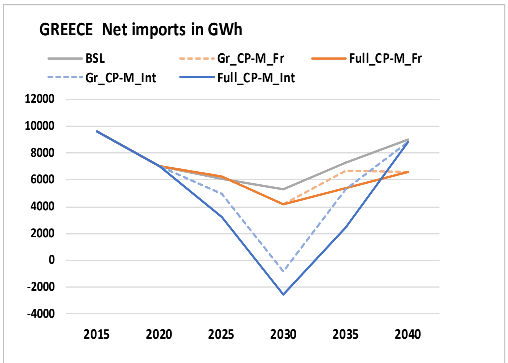
Montenegro is a net importer of electricity in all scenarios. After 2035 and in fragmented markets, Montenegro starts to export, exploiting domestic hydro sources. Irrespective of full or gradual carbon pricing, market integration induces a remarkable rise in imports until 2030, as lignite generation becomes expensive and trade opening allows using imports for balancing the increasing variable RES.

FIGURE 28: NET IMPORTS OF BOSNIA AND HERZEGOVINA IN GWH



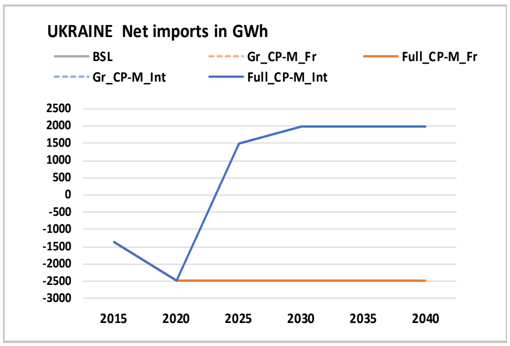
Bosnia and Herzegovina is likely to remain a net exporter throughout the projection period. Exports increase only slightly without carbon pricing. Reversely, carbon pricing exerts significant pressure on solids-based exports. Market integration allows replacing solids-based exports with imports of low- and carbon-free resources in 2020-2030, accelerating the country's energy transition. Market fragmentation exerts pressure on exports only in the second half of the projection period, preventing Bosnia and Herzegovina from recouping the decrease in solids-based exports, as opposed to market integration, where low or carbon-free exports surge again from 2030 onwards.

FIGURE 29: NET IMPORTS OF GREECE IN GWH



Greece continues to be a net importer under baseline conditions. Assuming that markets integrate and full carbon pricing applies in the EnC, Greece is in a position to provide the balancing resources that solids-dependent CPs need to back the deployment of variable RES and avoid carbon lock-in in the critical 2020-2030 period. Should markets remain fragmented, irrespective of gradual or full carbon pricing, then Greece will remain dependent on imports, and more so after 2030, when nuclear power is added to the generation mix in Bulgaria and Romania.

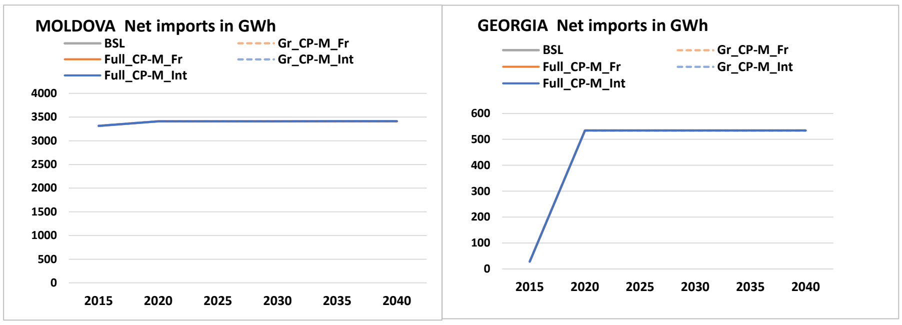
FIGURE 30: NET IMPORTS OF UKRAINE IN GWH



Ukraine remains a net exporter under baseline and market fragmentation trends. When markets are integrated, assuming Ukraine is better coupled with the European market via Romania, the projection foresees Ukraine to become an importer of reserves and energy.

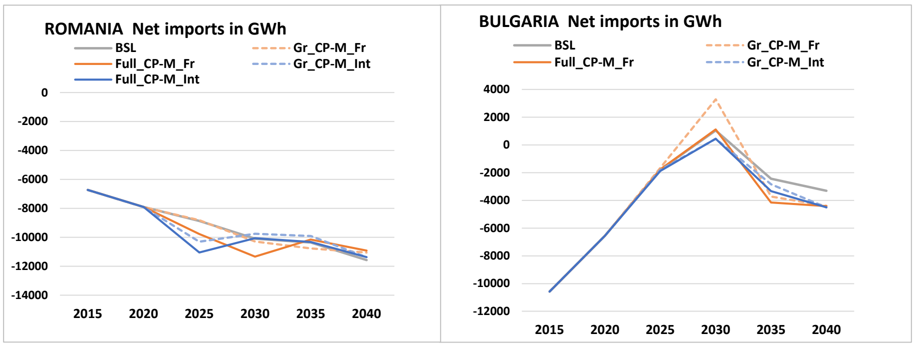
Moldova has outdated electricity generation capacities, which make it highly dependent on imports to meet demand and this is something not foreseen to change dramatically in the future under all scenarios. Therefore, Moldova remains a net importer across scenarios and timeframes. With full resilience to carbon pricing and market conditions being irrelevant, Georgia continues to be a net electricity importer in order to meet the rising demand, which is growing faster than generation.

FIGURE 31: NET IMPORTS OF MOLDOVA AND GEORGIA IN GWH



Exporting capabilities in Bulgaria decline, as solids-based generation becomes expensive and other sources expand poorly. Breaking off past trends, Bulgaria is likely to become a net importer towards 2030. The expansion of nuclear and variable RES together with gas-based generation favor electricity exports, turning Bulgaria again into a net exporter in the course of the next decade. Meanwhile, Romania's exporting profile is sustained under all scenarios, and more so under market integration projections, since the expansion of gas nuclear and RES in Romania can accommodate the increasing need for green imports of solids-dependent CPs in their energy transition.

FIGURE 32: NET IMPORTS OF BULGARIA AND ROMANIA IN GWH



6.3 Outlook of electricity prices

The study focuses on retail prices of electricity (excluding taxes and grid costs), because retail prices reflect recovered costs and can be revealing of the impacts of carbon pricing on private consumers (affordability) and industry (competitiveness). Capital costs (not yet amortized) and fixed operation and maintenance costs are reflected in retail prices too. It should be noted that capital costs differ by scenario; namely, if a scenario assumes that a certain plant is not operating or procuring ancillary services, such as reserves, then fixed capital and maintenance costs are not part of total costs. In the market integration scenarios, some of the coal plants do not operate and do not provide reserves thanks to the coordinated regional system control and operation replacing national systems. In this way, some of the national systems save on costs thanks to market integration and therefore consumer prices benefit.

Under Baseline trends, the lack of carbon pricing and the persistence of subsidies and other distortionary policies keep electricity prices low. The adoption of carbon pricing, however, implies a significant increase in prices. When allowances are auctioned and there is inability to reduce emissions equally, consumers bear high carbon costs. This is particularly relevant for coal-dependent CPs, either because they maintain heavy emitters in place despite mounting costs, or because they fail to develop carbon-free resources and balancing facilities in a timely manner.

Naturally, maintaining heavy emitters in operation for system purposes prevents high responsiveness to rising carbon costs. Likewise, poor conditions hindering the development of carbon-free resources and their balancing facilities also reduce resilience to carbon prices. Most importantly, if full carbon pricing applies within a fragmented market and poor gas supply conditions, then prices will rise significantly. Gradual carbon pricing under similar conditions leads to poor gains in emission reduction in the medium- and long-term, preventing the system from transforming according to potential, hence making electricity prices vulnerable to full carbon pricing in the future.

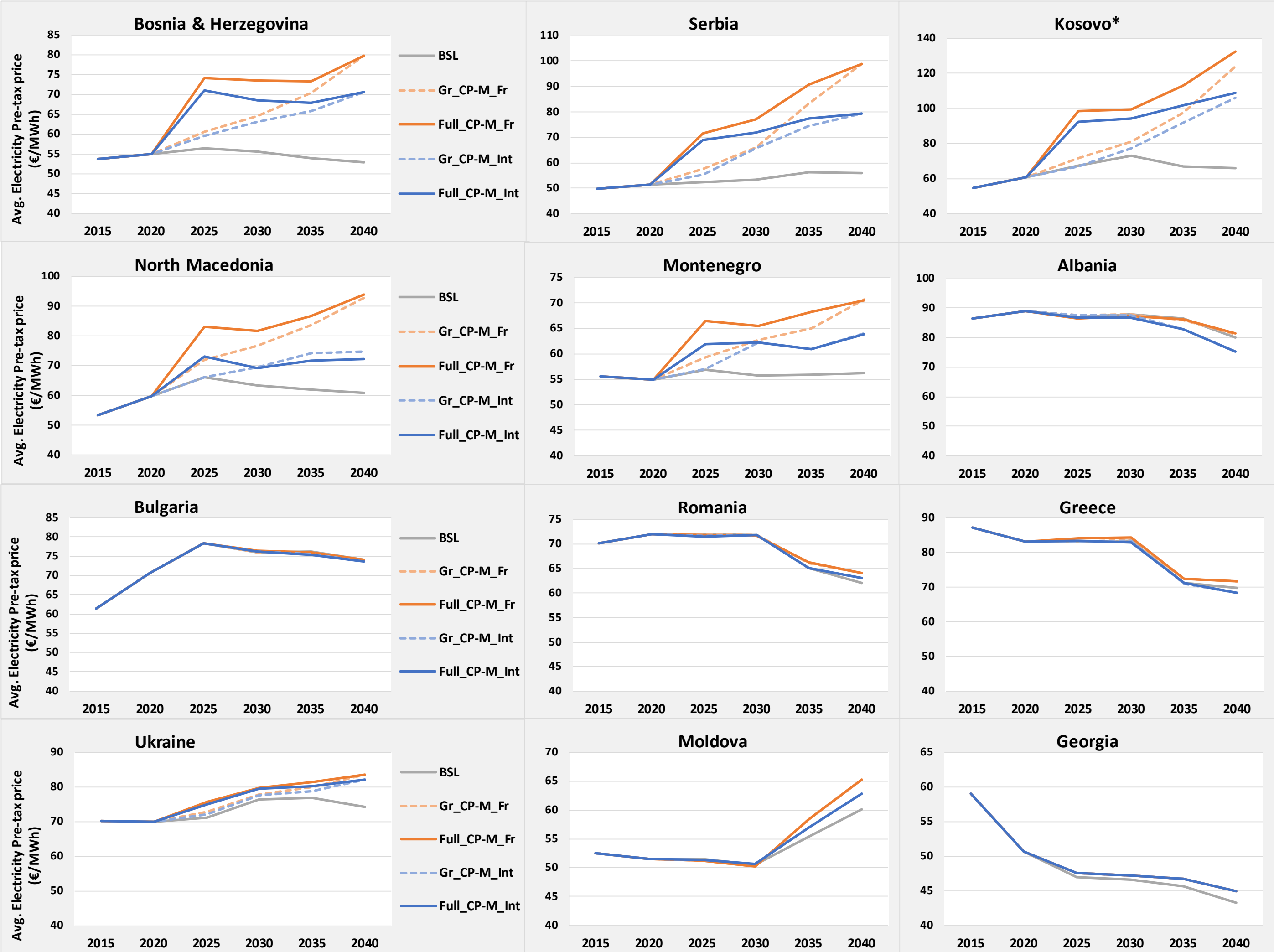
Market integration and facilitation of gas investment can relax system constraints, by enabling imports of low- and carbon-free resources and balancing, while mobilizing investment in RES, in the medium-term. Altogether, these conditions help maintain electricity prices within a reasonable range. Especially in carbon-intensive countries, even gradual carbon pricing under market integration conditions may be a viable solution for mitigating the severe social and economic consequences of carbon pricing in the medium-term. Generally, projections point to higher price convergence among the CPs when markets are integrated. Still, however, divergences in electricity prices exist, owing to the variations in the power mix of each CP that implies different levels of flexibility towards carbon pricing.

In Albania and Georgia, retail market prices follow a downward trend in all scenarios, since both countries have green power systems with ample flexibility and balancing resources based on hydropower. In Albania, the steepest drop in prices is envisaged under market integration conditions, irrespective of whether carbon pricing applies gradually or fully. In those conditions, variable RES, becoming growingly competitive, develop faster and additional hydro capacities enter the system. Market integration allows Albania to make a more efficient use of its resources by boosting carbon-free electricity exports towards CPs with low flexibility to carbon pricing. Meanwhile, a system largely based on RES and with plans to increase gas efficiency, Georgia will bear no adverse effects from carbon pricing and so the prospects for electricity prices are positive.

Except Albania, all other Western Balkan CPs exhibit vulnerability to carbon pricing, yet to varying degrees. There prices follow a similar path across scenarios. Under Baseline trends, reliance on solids persists despite rising costs, which are offset by the provision of electricity subsidies and other acts of under-pricing. Domestic resources are sufficient to maintain prices relatively stable and balance the moderate development of RES. While the Baseline scenario projects the lowest market prices in the absence of carbon pricing, when the latter applies fully, costs increase dramatically. Market integration helps mitigate the upward pressure on prices, by allowing CPs to import less expensive low-carbon electricity and balancing to support the development of variable RES. Market fragmentation on the other hand fails to attenuate the unfavourable consequences of carbon pricing, resulting in a striking rise in market prices, which persists until 2040. In Ukraine, carbon pricing induces a significant increase in prices irrespective of market conditions.

The projections show the persistence of increasing electricity prices in Bulgaria in all scenarios until 2025. The pricing of carbon emissions due to the abolishment of free allowances, combined with the increasing costs of mining and the poor development of variable RES and efficient gas drive an increase in generation costs, reflected in higher retail prices. The addition of nuclear capacity in the system combined with coal phase-out post-2030 results in a slight drop in prices, which stabilise from 2035 onwards. In Romania, the phase-out of coal and addition of carbon-free resources cause retail market prices to drop post-2030. The ambitious plan of modernizing its power fleet allows Greece to offset fully the threat of price increase via the development of efficient gas units and variable RES in the first half of the projection period. The decarbonisation of the power and end-use sectors, relying on the synergetic interaction between large-scale deployment of variable RES and production of climate-neutral fuels, helps reduce power and load fluctuations, improve system reliability and flexibility, and reduce electricity generation and final consumer prices in the period between 2030 and 2040.

FIGURE 33: EVOLUTION OF RETAIL ELECTRICITY PRICES ACROSS SCENARIOS



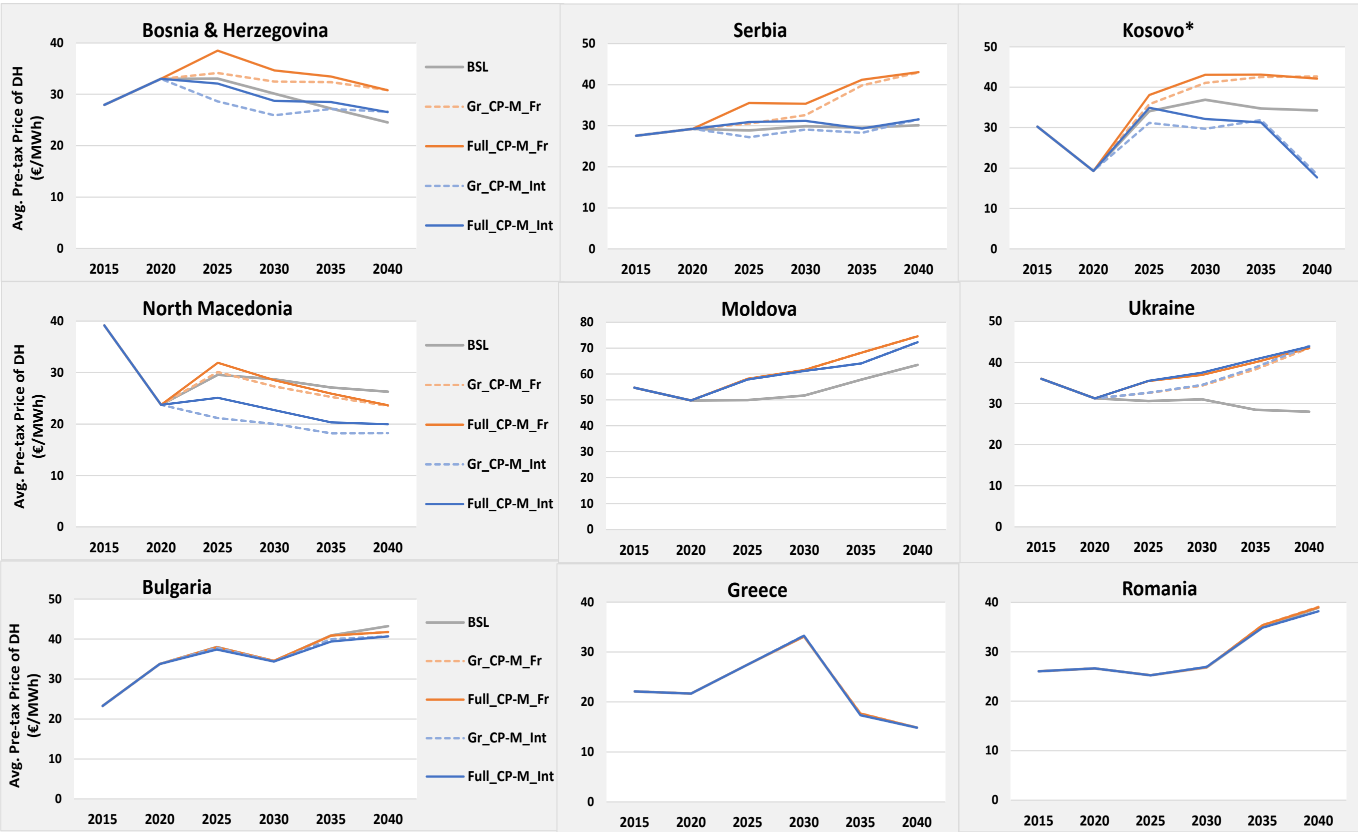
6.4 Projection of district heating prices

Baseline trends project district heating systems to continue relying solids and gas. Co-generation plants that use mainly coal make up the largest share of heat production in Bosnia and Herzegovina and Kosovo*, followed by heat-only units that consume gas and to a lesser extent coal. In Serbia, heat-only units based on coal contribute twice as much to heat production, compared to co-generation. In North Macedonia and Ukraine, co-generation relying mainly on gas (and to a lesser extent on coal and nuclear in Ukraine) prevails, while heat production continues to depend solely on gas in Moldova.

Fossil fuels being by far the dominant energy source in district heating in the EnC means carbon pricing will have a significant impact on prices. Heating prices remain within a reasonable range and emissions drop when market integration applies. This is because market integration and improvement of gas supply conditions are crucial for the economics of district heating, since the latter largely depends on co-generation and the use of gas. Projections foresee that market integration reduces and/or stabilizes heat prices post-2025 in most CPs. Contrariwise, full carbon pricing in a fragmented market brings about a significant increase in heat prices until 2040, *for* market fragmentation maintains solids in the energy mix and deteriorates gas supply conditions.

In systems with low resilience to carbon pricing, like Serbia and Kosovo*, the difference in heating price trends between market integration and fragmentation is striking. In Bosnia and Herzegovina and North Macedonia, market integration drives a swift and profound decline in heat prices from 2025 onwards. In Ukraine, heating prices increase in all scenarios except the baseline, due to carbon pricing. Similarly, in Bulgaria and Romania the more expensive energy mix due to increased carbon prices and new CHP plants replacing older ones drives prices up in all scenarios.

FIGURE 34: EVOLUTION OF DISTRICT HEATING PRICES ACROSS SCENARIOS

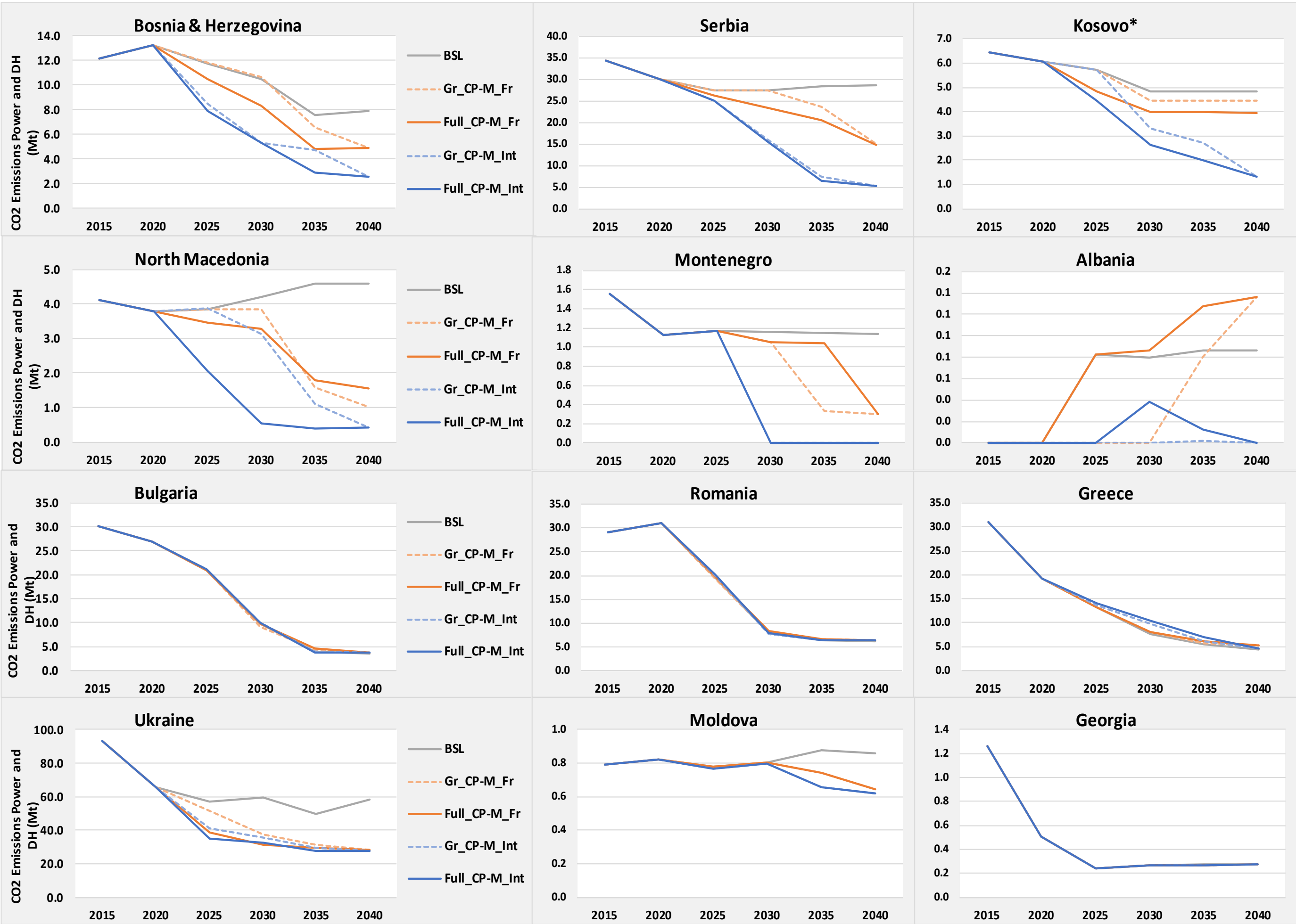


6.5 Outlook of CO2 emissions in power and district-heating

The outlook of CO2 emissions under Baseline conditions undergoes no remarkable changes, only minor reduction associated with the refurbishment of thermal plants and the modest development of variable RES and gas. Carbon pricing on the other hand brings about a significant reduction in CO2 emissions, as expected. The catalyst for significant and swift emission reduction and more so before 2030 is, however, market integration, because it enables the CPs to cut emissions and carbon intensity more quickly and deeply. In fact, carbon pricing and market integration provide a strong impetus for power and district heating systems to transform into low-carbon systems in 2040 and in several countries in 2030 already.

Full carbon pricing points to a marked reduction in emissions and carbon intensity. Still, even when applied gradually, carbon pricing triggers a notable drop in emissions. Combined with market integration, carbon pricing can more than halve carbon intensity of power and district heating in carbon-intensive CPs until 2030. Consequently, carbon-free power becoming increasingly available drives significant emission reduction in sectors i.e. heating and transport, most difficult to decarbonize. Should markets remain fragmented though and carbon pricing apply gradually, emission reduction until 2030 is not obvious compared to baseline trends, while carbon intensity declines moderately until 2030 and remains markedly high in 2040.

FIGURE 35: CO2 EMISSIONS IN POWER AND DISTRICT-HEATING ACROSS SCENARIOS



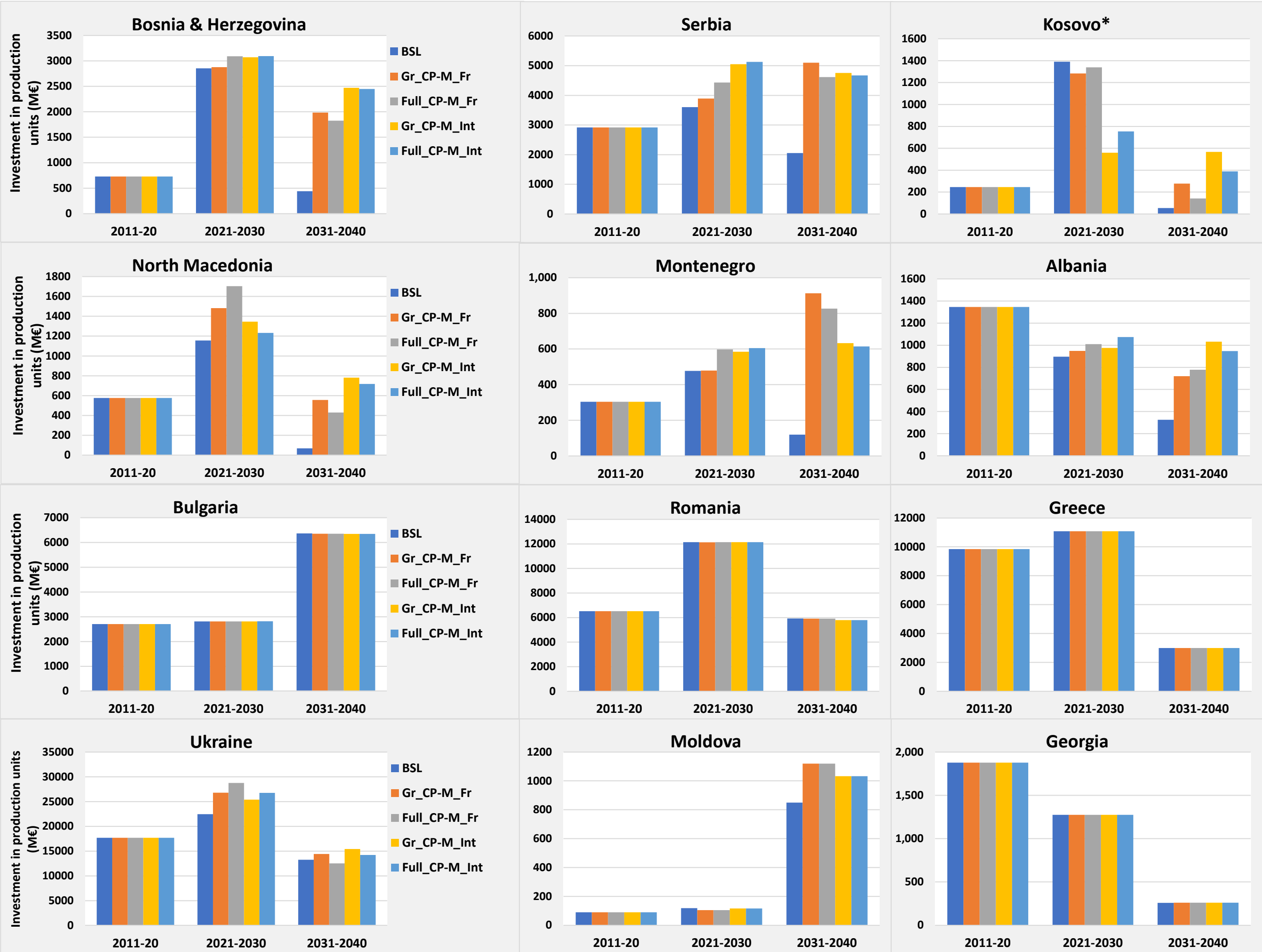
6.6 Trends in investment expenditures

The pathway to low-carbon electricity in the EnC is capital-intensive, as expected. The capital amounts needed in the future are much higher than in the recent past and the bulk of investments takes place primarily in the first decade, in most of the countries. The CPs will need to support the deep transformation of a large fraction of their solids-based power generation assets, which in many cases have reached or are close to reaching the end of their operational lives. These assets still represent the lion's share of generation capacity and so the challenge is greater, implying an almost complete overhaul of the power systems in the majority of CPs within the next decade.

Introducing carbon pricing and simultaneously accelerating the integration of power and gas markets is the key cost-effective action for CPs to decarbonise their power sectors, cut emissions and mobilise financing for the transition. In fact, these conditions accelerated coal phase-out and triggered remarkable investment in RES and clean technologies in the previous years in the EU MS. Meanwhile, as costs for renewable energy technologies decrease, investment savings increase in the long-term. Over the next decade, onshore wind and solar PV will represent a less expensive source of electricity compared to fossils, and more so without financial assistance. That said, market integration allows for investment cost-savings in the medium-term, since it maintains fewer domestic resources for system purposes, by facilitating the sharing of low-cost, low-carbon resources, as well as balancing and reserves and increases expenditures in the long-term, as it encourages restructuring investment flows. Under market integration, investors perceive the entire market, feel less exposed to risk and more incentivised to develop large-scale decarbonisation projects serving the region as a whole. Investment costs of large CCGTs are in a range 500 to 650 EUR/kW of installed capacity (overnight costs). The investment costs of RES technologies are decreasing in the future and are taken from the results of the consultation performed for the Green Deal scenarios of the European Commission (Spring 2020).

On the contrary, market fragmentation implies the transition is domestic, lasts longer and investment attractiveness remains low in the long term, in response to the small size and limited institutional, competition and logistics maturity of the domestic market. These conditions allow variable RES to expand only modestly in the future. Conversely, annual capital expenditures increase in the medium term in a context of market fragmentation, because CPs invest to reduce emissions and at the same time maintain non-optimal resources in operation for system purposes. Moreover, when carbon-free resources fail to develop adequately and fossils remain in the system, causing emissions to drop slower than required to offset rising taxation costs, then total operating expenditures will increase over time. This is most relevant for the carbon-intensive Western Balkan CPs. Thus, under the assumption that markets remain fragmented, a viable solution for solids-dependent CPs may be to apply gradual carbon pricing, in order to mitigate the rising operating expenditures. Within a context of market integration however, where RES are deployed swiftly enough to speed-up emission reduction and compensate for the rising costs of emission taxation, annual operating expenditures drop over time. Clearly, market integration brings operating costs down more than fragmentation, but cannot prevent operating costs from rising at all, in some cases.

FIGURE 36: OUTLOOK OF INVESTMENT EXPENDITURES ACROSS SCENARIOS

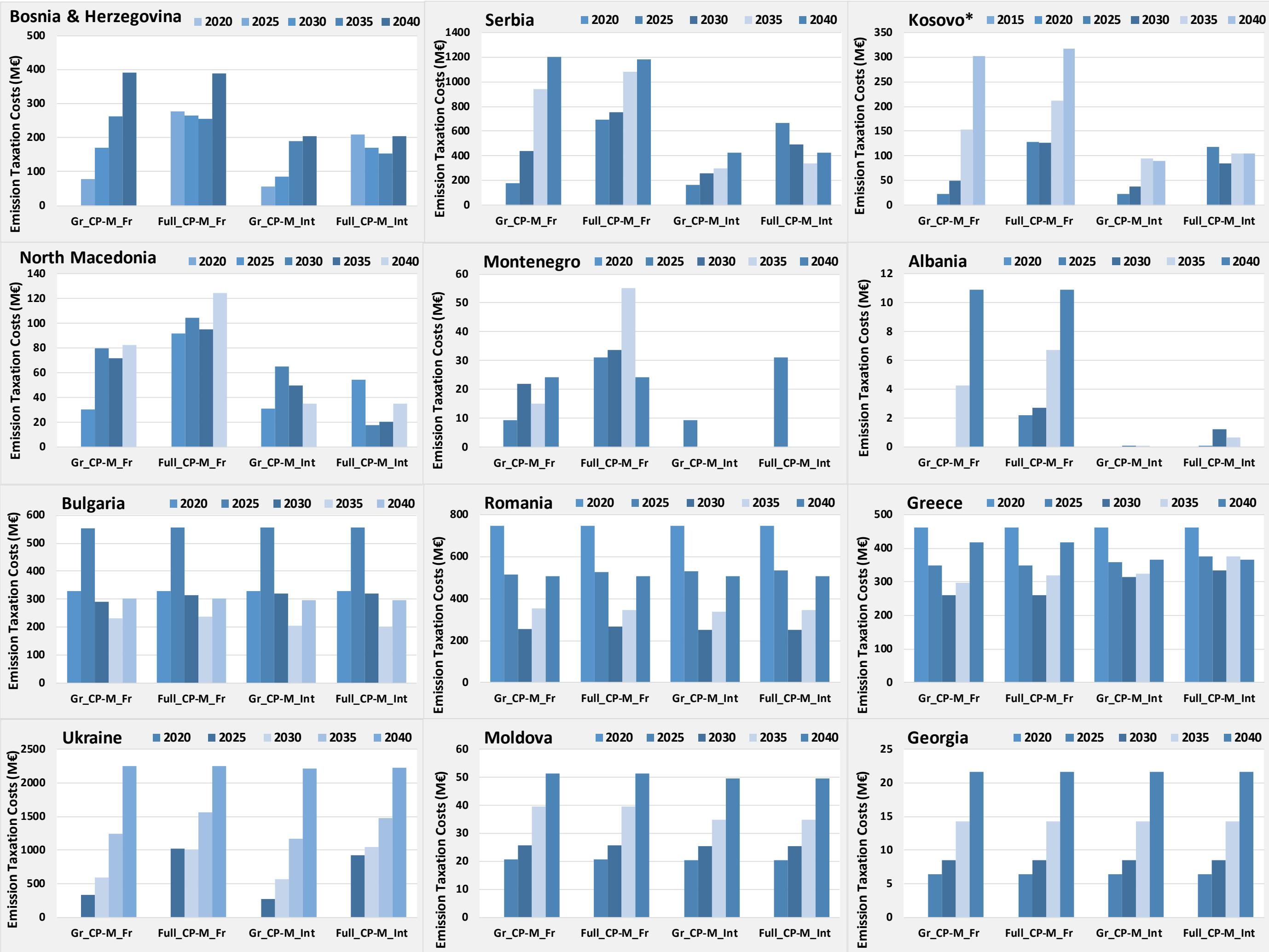


6.7 Projection of emission taxation costs

The costs stemming from carbon pricing represent revenues for the state. Unsurprisingly, costs are higher if carbon pricing applies fully rather than gradually. However, with market integration, carbon-intensive countries, being more exposed to carbon pricing, face fewer costs than under market fragmentation conditions. This is because market integration shields CPs against the negative effects of carbon pricing.

Market integration drives policy harmonization across CPs and offers investors in low- and carbon-free facilities regulatory certainty. Moreover, it allows the CPs, especially coal-dependent ones, to gain access to low-cost and low-carbon resources and restructuring investment and help them diversify their power mix, increase their flexibility to carbon pricing and swiftly transition away from fossils. Last, it removes existing market imperfections to improve the performance of carbon pricing. These enabling conditions triggered by market integration can ease the negative effects associated with emission taxation costs significantly.

FIGURE 37: EMISSION TAXATION COSTS ACROSS SCENARIOS (M€)



6.8 Outlook of a Cross-Border Adjustment Carbon Tax

The CBAT scenario is a variant of the Baseline scenario. It was developed in order to project the implications of a tax on coal-based electricity exports from the CPs to the EU. Imposing such a tax is part of the European Green Deal proposal and seeks to prevent electricity imports from third countries, not subject to carbon pricing, from increasing. Mitigating the risk of carbon leakage, bolstering the integrity of EU climate policy and incentivising the decarbonisation of electricity generation and the spread of carbon pricing in third countries are amongst the arguments in favour of applying the tax.

The CBAT scenario assumes that a carbon tax equal to the EU ETS carbon price applies on electricity exports from non-EU countries to the EU, in proportion to the CO2-intensity of the country of origin. The projection foresees that the border tax will reduce CO2 emissions, yet less than anticipated. At the same time, it will increase total costs for consumers overall in the region, and even more so in countries with carbon-intensive exports. Eventually, the tax will apply on the power mix as a whole, and not just on coal, therefore it will not reshuffle the merit order. In fact, the impact on gas and RES is expected to be greater than on coal, since the tax affects resources that are high in the merit order.

Having said that, the study supports the idea that applying a carbon tax on EU borders is an inferior policy option compared to introducing an emission trading system in the CPs of the EnC. This viewpoint is also shared by other studies conducted recently[35]. Expanding the geographical scope of the EU ETS is a more effective climate policy tool because it creates a level playing field among countries and achieves real emission reduction, by effectively eliminating solids from the power system, while providing an adequate signal for investment in low-carbon projects. An extended EU ETS will ensure energy systems already partly integrated with the EU, like those of the Western Balkans, get even more embedded in the EU internal market.

FIGURE 38: PROJECTION OF CROSS-BORDER TAX ON POWER IMPORTS TO THE EU

	Bosnia&Herzegovina				Serbia				Kosovo (*)			
	2025	2030	2035	2040	2025	2030	2035	2040	2025	2030	2035	2040
Imports (GWh)	0.	0.	0.	0.	0.	0.	0.	0.	-2.4	3.1	7.5	-45.9
Exports (GWh)	-91.8	-508.5	-632.5	-920.5	-82.2	-494.3	-759.8	-1,310.7	0.	0.	0.	0.
Power Gen from coal (GWh)	0.	0.	0.	-41.1	0.	0.	0.	0.	0.	0.	0.	0.
Power Gen from gas (GWh)	0.	0.	0.	0.	0.	-1.5	0.	0.	0.	0.	0.	0.
Power Gen from RES (GWh)	-91.8	-525.	-660.6	-931.6	-82.1	-492.7	-760.	-1,311.2	0.	0.	-3.7	55.1
CO2 Emissions (Kt)	0.	0.	0.	-37.5	0.	-0.3	3.	-0.6	0.	0.	0.	0.
Consumers' cost of electricity (M€)	0.8	3.1	3.3	3.9	0.9	6.9	13.2	23.9	-0.3	0.6	0.6	2.5

	Montenegro				North Macedonia				Albania			
	2025	2030	2035	2040	2025	2030	2035	2040	2025	2030	2035	2040
Imports (GWh)	51.9	23.3	159.7	219.2	0.	182.1	216.4	497.7	0.	0.	22.3	52.7
Exports (GWh)	0.	0.	0.	0.	0.	0.	0.	0.	-52.2	10.2	-97.3	-73.9
Power Gen from coal (GWh)	0.	0.	0.	0.	0.	0.	0.	-189.2	0.	0.	0.	0.
Power Gen from gas (GWh)	0.	0.	0.	0.	0.	0.	0.	-72.	-35.3	7.6	-0.4	-7.6
Power Gen from RES (GWh)	-51.9	-23.1	-159.4	-218.7	0.	-181.4	-218.4	-228.4	-16.6	2.9	-118.8	-118.5
CO2 Emissions (Kt)	0.	0.	0.	0.	0.	0.	0.	-239.8	-14.6	3.1	-0.2	-3.1
Consumers' cost of electricity (M€)	0.2	0.2	0.8	-0.6	-1.3	2.5	-3.9	-10.5	1.7	0.1	3.4	1.8

	Bulgaria				Romania				Greece			
	2025	2030	2035	2040	2025	2030	2035	2040	2025	2030	2035	2040
Imports (GWh)	0.	330.6	0.	0.	0.	0.	0.	0.	248.5	258.2	586.7	330.9
Exports (GWh)	-103.7	0.	-192.3	-41.9	-949.4	0.1	-18.2	-159.8	0.	0.	0.	0.
Power Gen from coal (GWh)	-98.3	-186.3	0.	0.	-983.6	0.	0.	0.	-2.8	0.	0.	0.
Power Gen from gas (GWh)	-5.3	-139.8	-97.	-38.3	34.2	0.	-27.8	-125.5	-245.7	-245.4	-550.5	-319.3
Power Gen from RES (GWh)	0.	-4.4	-49.3	-34.6	0.	0.	0.	-30.6	0.	-12.1	0.1	-14.
CO2 Emissions (Kt)	-137.8	-274.8	-22.4	-5.4	-1,228.7	0.	-9.4	-42.3	-86.4	-88.6	-186.6	-105.1
Consumers' cost of electricity (M€)	1.7	-1.6	3.4	-2.7	7.3	0.	-4.2	-4.2	-1.	-2.1	1.1	-4.8

	Balkans Total					Ukraine			
	2025	2030	2035	2040		2025	2030	2035	2040
Imports (GWh)	298.	797.2	992.6	1,054.6	Imports (GWh)	0.	0.	0.	0.
Exports (GWh)	-1,279.2	-992.5	-1,700.	-2,506.8	Exports (GWh)	-803.4	-1,461.6	-1,919.8	-2,418.6
Power Gen from coal (GWh)	-1,084.8	-186.3	0.	-230.3	Power Gen from coal (GWh)	-40.3	-450.5	-38.4	-38.4
Power Gen from gas (GWh)	-252.2	-379.	-675.7	-562.8	Power Gen from gas (GWh)	0.	0.	-1,329.4	-1,280.4
Power Gen from RES (GWh)	-242.4	-1,236.	-1,970.1	-2,832.4	Power Gen from RES (GWh)	-763.1	-1,011.	-531.8	-1,080.3
CO2 Emissions (Kt)	-1,467.5	-360.6	-215.5	-433.7	CO2 Emissions (Kt)	-59.2	-682.1	-427.6	-414.8
Consumers' cost of electricity (M€)	9.9	9.6	17.8	9.3	Consumers' cost of electricity (M€)	31.4	60.6	-17.8	-3.6

[35] RAP, REKK (2020) "Extended ETS outperforms carbon border adjustment in the power sector" file:///C:/Users/DELL/Downloads/DeCarbon201010_REKK.pdf

7 The socio-economics of carbon pricing

7.1 Impact on the economy

Changes in the generation mix affect the economy mainly in two ways: through the additional investments required to build the power generation plants and through the changes in electricity prices. Investments stimulate demand and create a positive multiplier effect in the economy, while the increase in electricity prices affects the competitiveness of firms and the real disposable income of households.

Funding availability and costs are critical parameters for determining the impact of investments on the economy. In economies with scarce financial resources, additional investment in RES raises the demand for capital, which drives interest rates upwards and can lead to crowding-out effects. Therefore, the cost of financing RES deployment should be low and the local economy should be actively involved in producing the necessary capital goods for the economy to reap the benefits of RES. However, CPs have limited or no capacity for manufacturing renewable energy equipment. Most of the equipment is imported. Thus, the key multiplier effect stems from construction services and other materials required for installing the different power generation equipment.

To calculate the impact of the alternative carbon pricing scenarios on CP economies, an output multiplier approach has been used. The underlying assumption is that financial resources suffice to support the additional investment, and so investment in RES expansion does not crowd out any other investment into the economy. The output multiplier approach accounts for the inter-dependencies among firms[36] and the capacity of each CP to produce the respective capital goods. As pointed out, the assumption is that, until the end of the projection period, CPs will not be in a position to produce wind turbines and PVs. Most of the capital goods and associated equipment will be imported. The creation of capital goods stimulates demand in specific sectors such as construction, equipment goods, materials, and services. The importance of these sectors in each country in terms of domestic content and back/forward linkages is the main factor that determines the multiplier effects of investing in RES.

7.1.1 Investment Requirements

The net investment requirements by country are estimated as the investment to build new RES capacity minus the investments in thermal power plants. This allows calculating the net economic impact. In almost all scenarios and countries examined, aggregate investments are higher in the carbon pricing scenarios than in the baseline scenario, which reflects the higher capital costs of RES technologies. Investments differ

[36] The output multipliers are calculated using the Input-Output tables of the EnC.

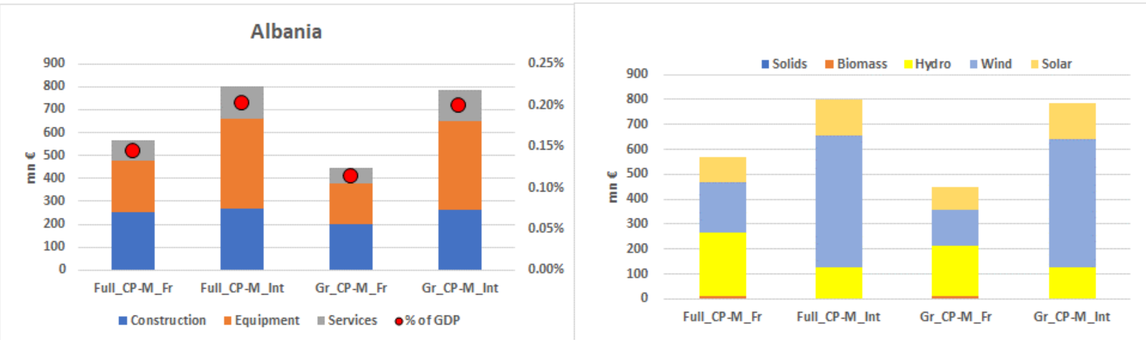
by country but on average, they range from 0.1 to 0.5% of GDP. Net investments are negative only in Kosovo* under the market integration scenario due to the non-deployment of new lignite plant (Kosova a Re). The investment by country, power generation technology, and sector of performance are presented in Figure 39.

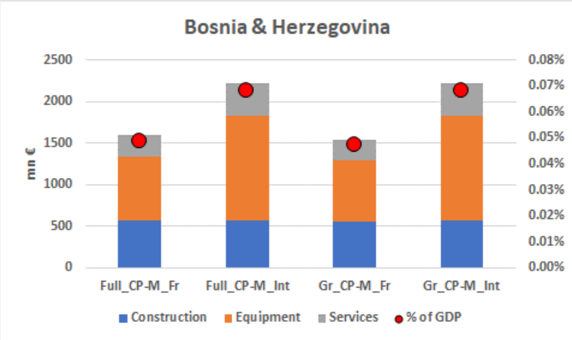
In Albania, investments for the 2020-2040 period are estimated to reach ~800 million € under the market integration scenarios and ~550 million € under the fragmented market scenarios. Demand for machinery and equipment in the market integration scenarios is estimated to be ~400 million whereas for construction ~250 million €. Investments related to equipment address mainly imported goods.

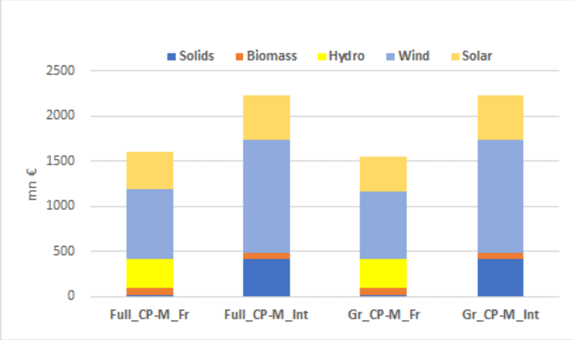
In Bosnia and Herzegovina, investments are channeled towards solar PV, wind, biomass and thermal power plants. Investments peak in the *Full_CP-M_Int* scenario, reaching ~2 billion €. The equipment industry mostly benefits from these investments. In Georgia, investments are directed only to solar PV. In Moldova, net investments amount to 250 million € and mainly concern the equipment goods industry. In carbon pricing scenarios, the deployment of lignite power plants decreases compared to Baseline trends, while main expenditure is made on the wind and PV power generation utilities. Montenegro needs to undertake significant investments in all scenarios, and more so under *Full_CP-M_Fr* scenario, where investments reach 800 million €.

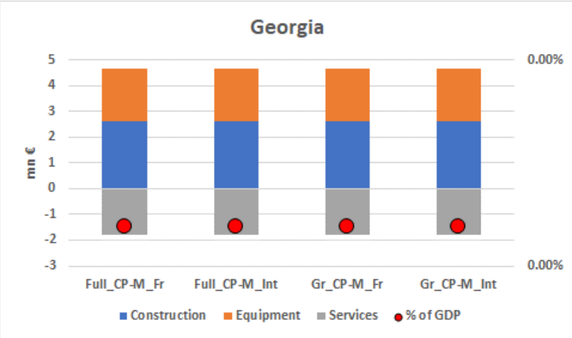
In North Macedonia, investments are mainly poured into the deployment of variable RES and natural gas. In Kosovo*, net investments on power generation technologies are estimated to be around 100 million € under market fragmentation conditions, but if markets integrate, then the Kosova e Re plant will not be deployed, and so investments will be lower than under baseline trends. In Serbia, net investments amount to 3.8 billion € and concern mainly variable RES projects, while in Ukraine total investments reach 4 billion € in the market integration scenarios and are mainly channeled towards wind projects.

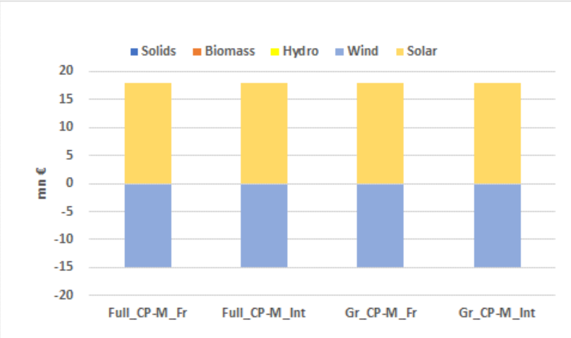
FIGURE 39: INVESTMENT BY TECHNOLOGY AND SECTOR OF PERFORMANCE IN THE CPS

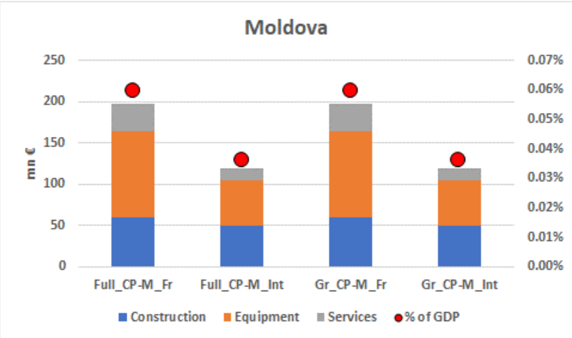


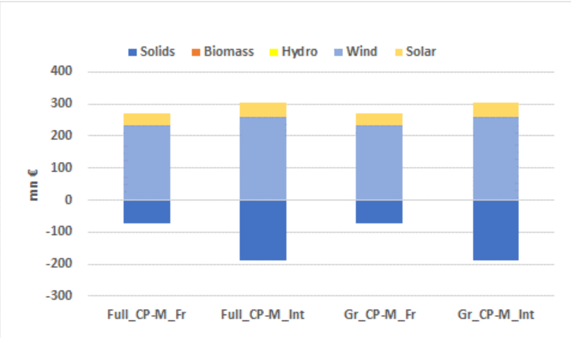

Bosnia & Herzegovina
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int
Construction
Equipment
Services
% of GDP

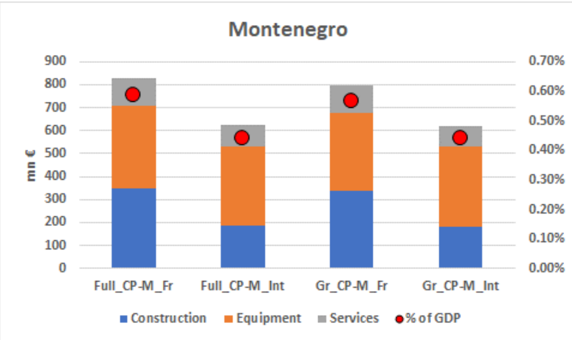

Solids
Biomass
Hydro
Wind
Solar
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int

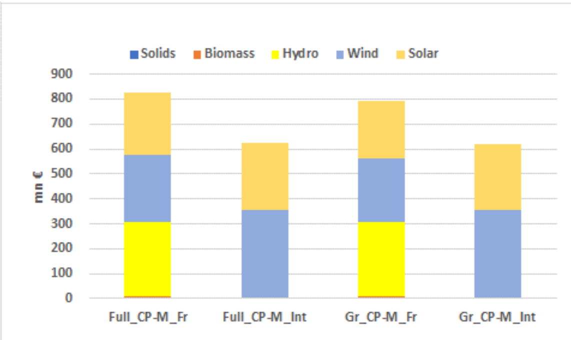

Georgia
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int
Construction
Equipment
Services
% of GDP

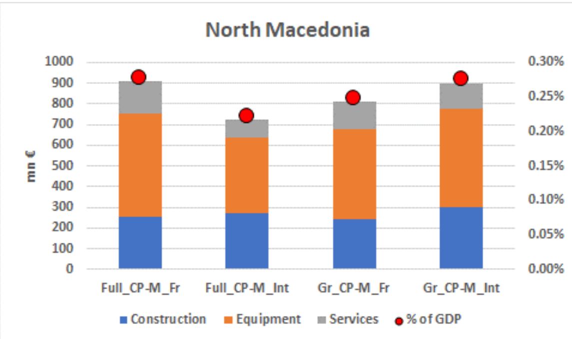

Solids
Biomass
Hydro
Wind
Solar
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int

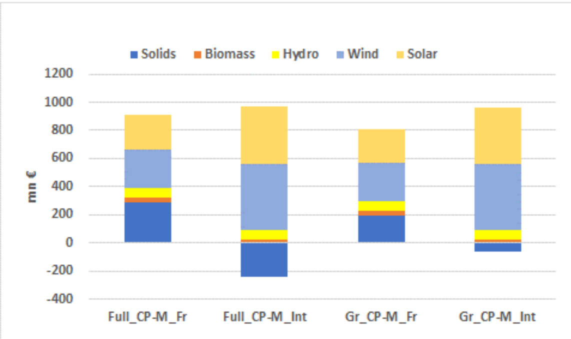

Moldova
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int
Construction
Equipment
Services
% of GDP


Solids
Biomass
Hydro
Wind
Solar
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int


Montenegro
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int
Construction
Equipment
Services
% of GDP


Solids
Biomass
Hydro
Wind
Solar
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int


North Macedonia
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int
Construction
Equipment
Services
% of GDP

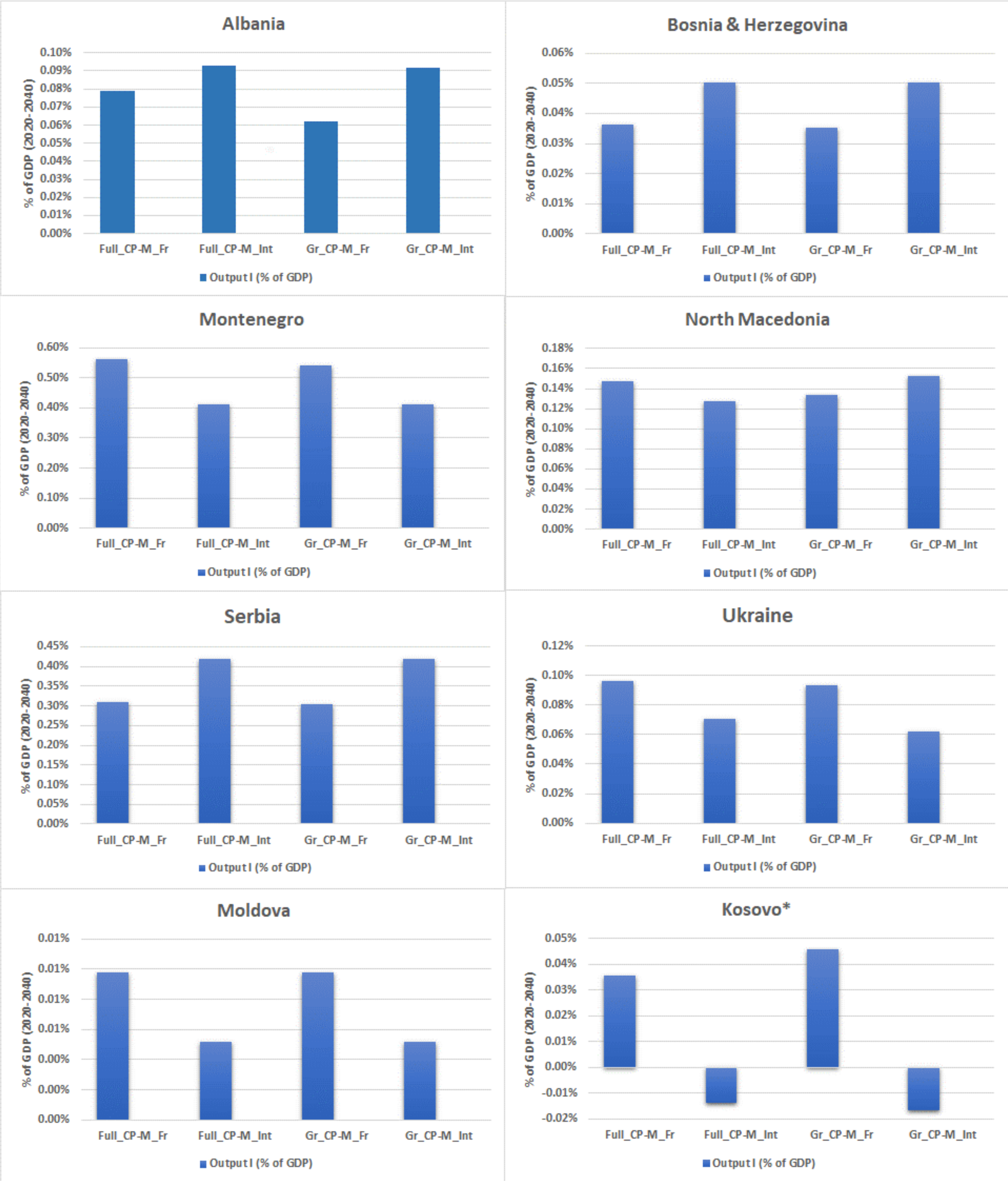

Solids
Biomass
Hydro
Wind
Solar
mn €
Full_CP-M_Fr
Full_CP-M_Int
Gr_CP-M_Fr
Gr_CP-M_Int

When these investments are treated as new money entering the economy, then they have positive multiplier effects. The degree of impact depends on the specific output multipliers of each country. These are computed using the country IO tables[37]. The realization of these investments is beneficial for CPs, both in terms of economic activity and employment.

Figure 40 presents the additional income that is generated from net investments in power generation. The impacts differ as in some countries taxes and imports represent a large share of GDP, reducing the performance of output multipliers. Also, it should be noted that Georgia is not included, since additional investments in solar PV are canceled by the drop-in wind investments. For this reason, the impact is extremely low, and so the economy is virtually unaffected.

[37] Input-Output tables for the countries have been extracted from the GTAP (https://www.gtap.agecon.purdue.edu/) and EORA (https://worldmrio.com/) databases.

FIGURE 40: ECONOMIC MULTIPLIER BENEFITS FROM RES INVESTMENT



As noted, the multiplier-based analysis does not capture the impact on firm competitiveness caused by changes in unit production costs, or the impact on households' disposable income. It accounts only for the economic multiplier effect that the new investments (additional to baseline) will deliver to each economy. The flexibility demonstrated by the capital market and financial system as well as the competitiveness of firms in each CP are two key factors influencing economic performance. *Specifically:*

To transform the power generation system, as a result of carbon pricing, requires additional investments. Depending on the expected returns on capital, stability and security of investment, and availability of financial resources in the CPs, the investments that will occur (on top of the Baseline) may cancel out investments in other sectors due to opportunity cost and/or cost of financing. This negative impact highly depends on the ability of the financial sector to pour “new loans” into the economy without increasing considerably the financing cost.

Furthermore, as long as there are no free allowances, the rise in the unit cost of electricity generation drives up the production costs of energy intensive firms. These firms, with high cost pass through rates, i.e. the ability of a firm not to increase its prices when its production costs increase, and exposure to trade, are expected to bear losses as a result of lower competitiveness, which will directly affect employment and subsequently household income.

7.2 Impact on employment

Carbon pricing drives the adoption of power generation technologies that are characterized by different labour intensities in their construction and operation phases. The study performs a multiplier analysis to calculate how the changes in the power system affect jobs. The study defines jobs as the additional jobs created on average for the period 2021-2040. One additional job represents one additional job for each year of the period 2021-2040.

The multiplier-based methodology accounts for the jobs that are generated during the construction of the power generation station and during the operation & maintenance of the station. It does not consider the indirect employment effects in others sectors as a result of the power system transformation in each scenario, as well as economic effects on other sectors of the economy and effects related to changes in production costs, disposable income and competitiveness.

The analysis considers both the employment that is generated from investments in RES, natural gas and biomass and the employment lost due to the disinvestment in fossil-fired power plants. The employment impact from fossil fuel supply and mining activities is captured separately. It is assumed that no local production of power generation equipment takes place, (PV, wind turbines etc.), and that all equipment is imported, hence employment effects are linked with employment in construction, operation and maintenance of power generation utilities. The analysis is based on the employment multipliers found in literature and presented in Table 26 and Table 27.

TABLE 26: EMPLOYMENT MULTIPLIERS[38] FOR POWER GENERATION TECHNOLOGIES

	Construction (job years/MW)	Manufacturing (job years/MW)	Operations and Maintenance (jobs/MW)					
	Rutovitz, 2015	Rutovitz, 2015	Rutovitz, 2015	Wei, 2011	USA, 2017	UNEP, 2008	Cameron 2015	Average
Wind	3.2	4.7	0.3	0.24	0.05	0.08	0.30	**0.19**
PVs	13	6.7	0.7	0.52	0.13	0.17	0.30	**0.28***
Large hydro	7.4	3.5	0.2	0.34	0.06			**0.20**
Biomass	14	2.9	0.65	0.12	0.08	0.16		**0.25**
Coal	11.2	5.4	0.18	0.40	0.16	0.38		**0.28**
Oil	1.3	1	0.14	0.10	0.16	0.16		**0.14**
Gas	1.3	1	0.14	0.10	0.15	0.15		**0.14**
Nuclear	11.8	1.3	0.6	0.70	0.46			**0.59**

* 0.7 multiplier from Rutovitz (2015) is not taken into account as it is considered an outlier.

TABLE 27: EMPLOYMENT MULTIPLIERS[39] FOR COAL FUEL SUPPLY (MINING AND ASSOCIATED JOBS), GAS AND BIOMASS

	Employment factor Jobs per PJ [S. Teske et. al (2018)]		
	Coal	**Gas**	**Biomass**
Eastern Europe/Eurasia	36.0	17.9	29.9

7.2.1 Albania

In 2018, total employment in Albania was approximately 1 million people and average unemployment rate reached 17.8%. The changes in the power generation system projected in Albania mainly concern the deployment of wind, solar PV, and biomass to some extent. In total, it is estimated that RES deployment will create 300 short-term jobs, primarily in construction of the power generation utility. The long-term, full-time equivalent jobs linked with operation and maintenance reach the maximum (80) in

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[38] Rutovitz, J., Dominish, E. and Downes, J. (2015). Calculating Global Energy Sector Jobs: 2015 Methodology Update, Prepared for Greenpeace International by the Institute for Sustainable Futures, University of Technology, Sydney.

Wei, M., S. Patadic and D. Kammen (2010), "Putting renewables and energy efficiency to work: How many jobs can the clean energy industry generate in the US?" Energy Policy, Volume 38, Issue 2, February 2010.

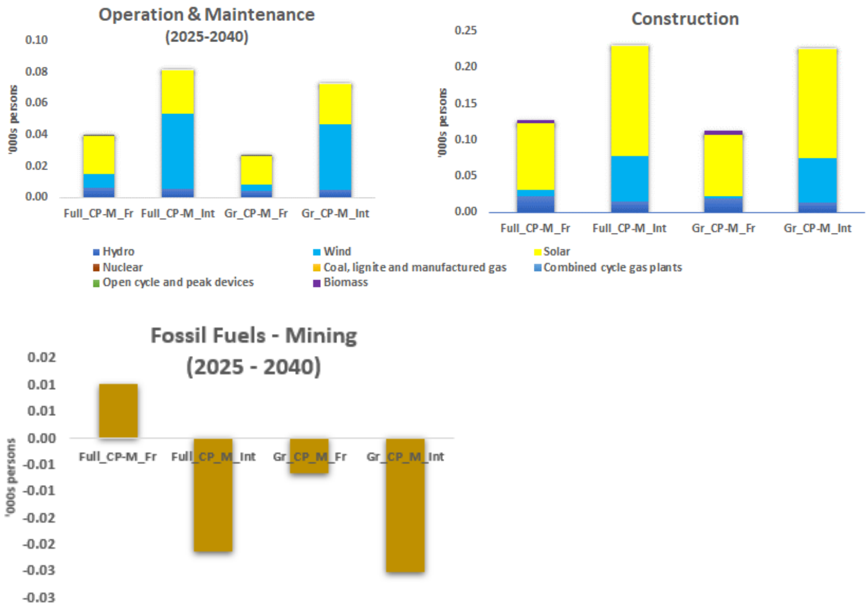
USA, Bureau of Labour Statistics, 2017, Data available at: https://www.bls.gov/oes/current/oessrci.htm
UNEP (2008), Green Jobs: Towards Decent Work in a Sustainable, Low-Carbon World, United Nations Environment Programme and International Labour Organisation, 2011.

Cameron L, Van der Zwaan BCC (2015), Employment factors for wind and solar energy technologies: A literature review, Renewable and Sustainable Energy Reviews 45 (2015), 160-172.

[39] S. Teske et. al (2018). "Achieving the Paris Climate Agreement Goals Global and Regional 100% Renewable Energy Scenarios with Non-energy GHG Pathways for +1.5°C and +2°C", Springer Nature Switzerland AG, Gewerbestrasse 11, 6330 Cham, Switzerland.

the *Full_CP-M_Int* scenario. Market fragmentation on the other hand more than halves employment compared to market integration, a direct consequence of the limited investment in solar and wind.

FIGURE 41: EMPLOYMENT TRENDS IN ALBANIA ACROSS SCENARIOS

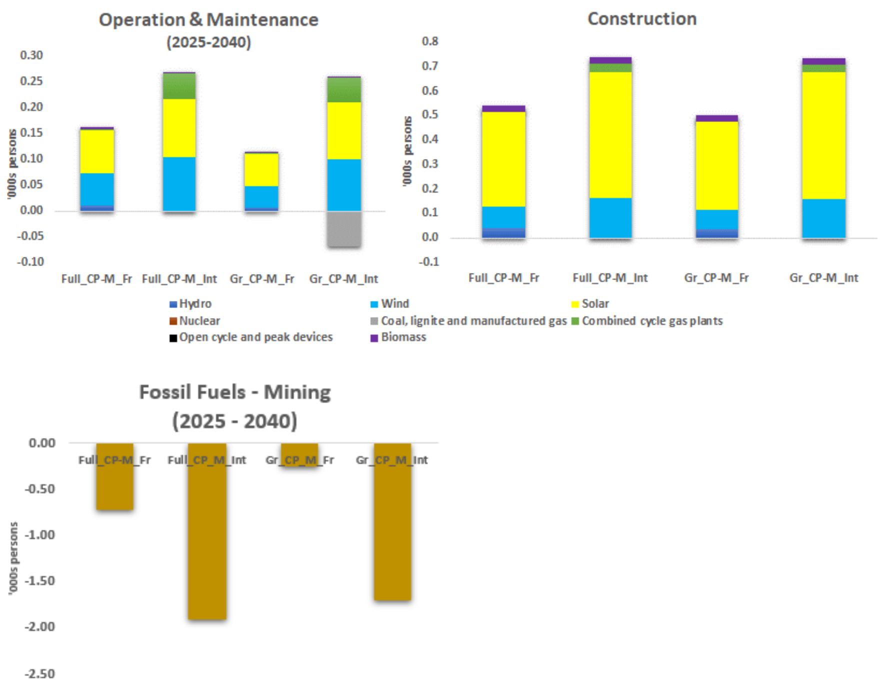


7.2.2 Bosnia and Herzegovina

In Bosnia and Herzegovina, employment is affected by investments in variable RES and gas-fired power plants and a decrease in solids-firing generation. Total employment increases across scenarios and peaks in the *Full_CP-M_Int* scenario with the creation of 700 jobs. The permanent jobs associated with the operation and maintenance of the utilities reach approximately 250 for the period 2025-2040. Most jobs are associated with solar PV and wind turbines. 100 are the jobs generated in the gas sector.

The underlying assumption is that in all scenarios thermal capacities continue to be online (at the Baseline level and do not decommission earlier) to ensure that the power system maintains a sufficient level of reserves. This implies that the impact on solids-fired power plant jobs is limited, as the fixed operating and maintenance costs are the same as in the Baseline. Nonetheless, the impact on coal mining is significant, with almost 2000 job losses projected to occur in the market integration scenarios.

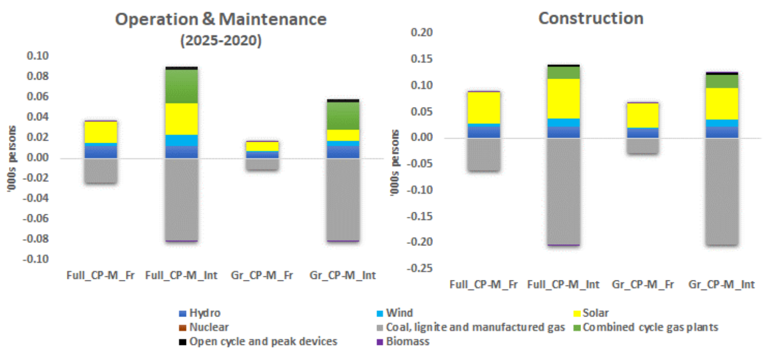
FIGURE 42: EMPLOYMENT TRENDS IN BOSNIA AND HERZEGOVINA ACROSS SCENARIOS

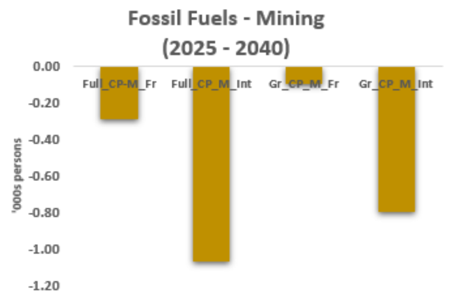


7.2.3 Kosovo*

The reduction of solids-firing generation in the market integration scenarios has a net negative impact on Kosovo*'s employment overall. Despite the deployment of solar PV and wind, employment drops by almost 100 jobs in the market integration scenarios, while 30 new permanent jobs are created in the market fragmentation scenario. This is because market fragmentation maintains solids in power generation and so investments are not cancelled out. In the market integration scenario, the number of lost jobs in the mining sector is more pronounced, reaching almost 1000 jobs.

FIGURE 43: EMPLOYMENT TRENDS IN KOSOVO* ACROSS SCENARIOS

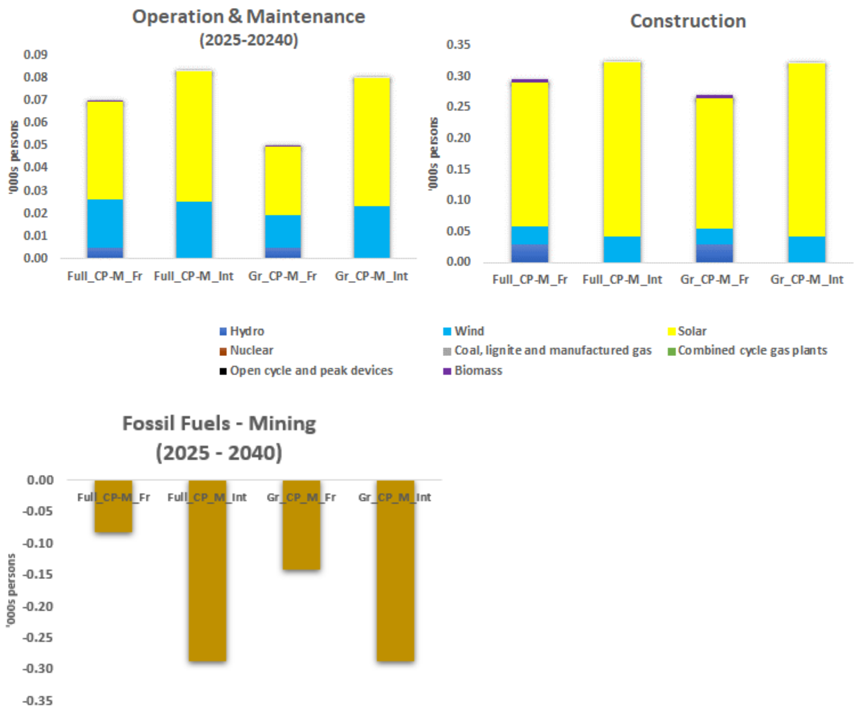




7.2.4 Montenegro

In Montenegro, changes in the power mix are expected to increase total employment by an average of 0.13%. Between 2025 and 2040, approximately 350 jobs will be created, of which 80 permanent ones[40]. The key driver is the deployment of solar PV. The expansion of wind, hydro, and biomass will also contribute positively to employment but to a lesser extent compared to solar PV. Like in Bosnia and Herzegovina, the impact on coal-fired power plant jobs may be limited, as fixed operating and maintenance costs remain unchanged, but coal mining will be significantly affected, with almost 2000 jobs being lost under market integration.

FIGURE 44: EMPLOYMENT TRENDS IN MONTENEGRO ACROSS SCENARIOS

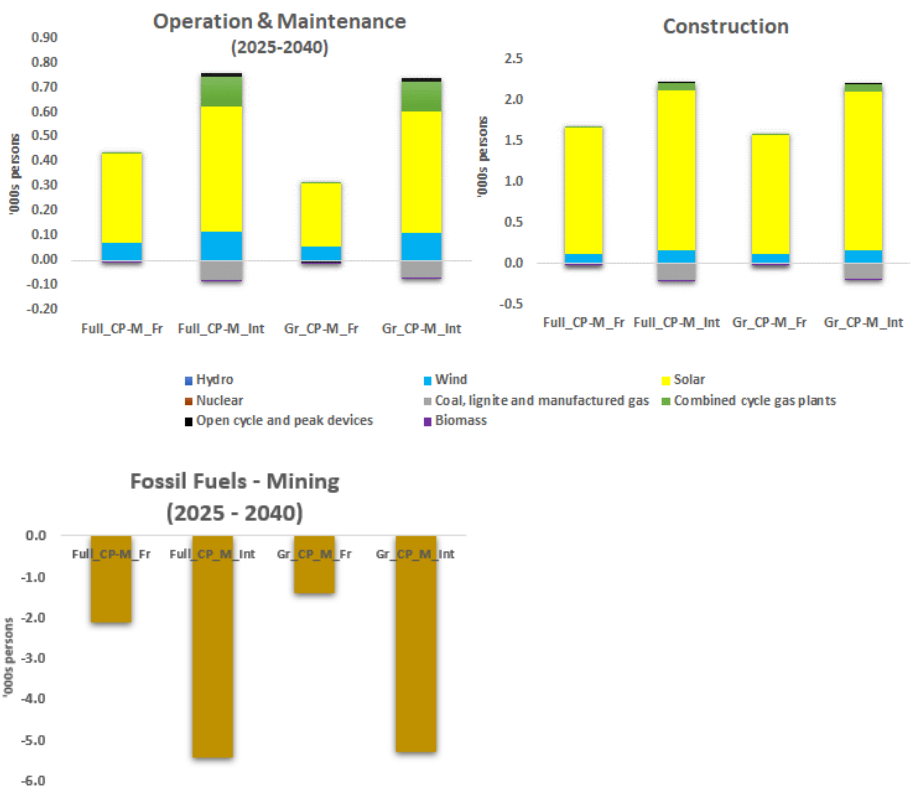


[40] Latest announcements regarding the commissioning of Komarnica HPP (172 MW) in 2028, imply the creation of, *on average and for the period 2021-2040*, 52 temporary jobs in the construction phase and 22 permanent jobs in the operation of the plant.

7.2.5 Serbia

Net employment in Serbia increases by 2000 jobs, driven by construction of solar PV plants. The positive net effect on employment in Serbia is driven by the higher investments needs in net capacity investments at power generation (this is true for each scenario when compared with the BSL scenario). The negative effects of solids-fired power generation are not significant. Almost 700 new permanent jobs are expected under market integration scenarios, which is almost double than those created under market fragmentation conditions. The impact on coal mining is notable, with approximately 5300 jobs projected to be lost under market integration conditions.

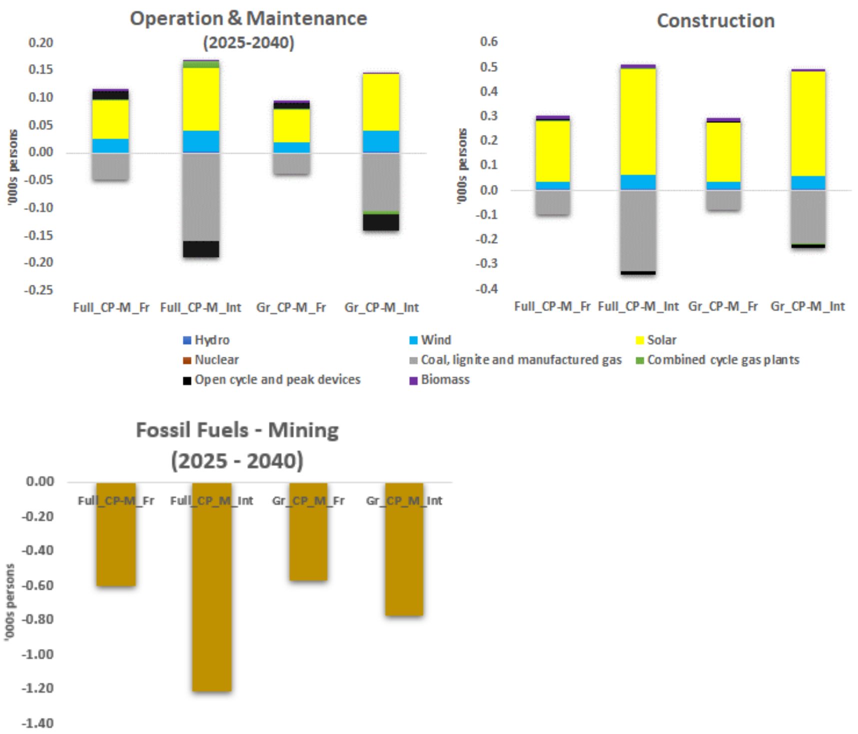
FIGURE 45: EMPLOYMENT TRENDS IN SERBIA ACROSS SCENARIOS



7.2.6 North Macedonia

The net impact on employment in North Macedonia is positive, yet largely driven by the construction of solar PV and lower investments in coal and open cycle and peak devices. An additional 270 jobs are created in the *Gr_CP-M_Int* scenario. In the *Full_CP-M_Int* scenario, almost 300 jobs will be lost due to lower investments in solids-fired plants but at the same time, 570 short-term jobs will be created in the solar PV, wind, and biomass sectors. In terms of permanent jobs, the fragmented scenarios offer better prospects than the market integration scenarios, because even though less RES are deployed, at the same time, fewer investments in solid thermal plants are cancelled. The impact on jobs from coal mines is important, with almost 1200 jobs envisages to be lost in the market integration scenarios.

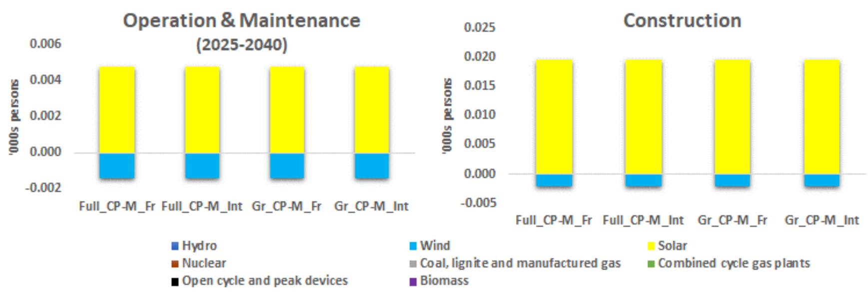
FIGURE 46: EMPLOYMENT TRENDS IN NORTH MACEDONIA ACROSS SCENARIOS



7.2.7 Georgia

In Georgia, the impact on employment is small. The only driver of additional jobs is the installation of solar PV, projected to generate 20 short-term jobs and 8 permanent ones.

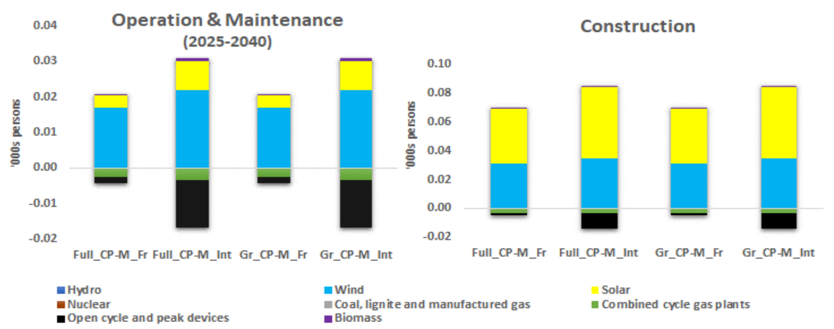
FIGURE 47: EMPLOYMENT TRENDS IN GEORGIA ACROSS SCENARIOS



7.2.8 Moldova

In Moldova, direct employment translates to 80 jobs being created on average, of which 35 permanent ones are associated with the deployment of wind and PV in the period 2025-2040. The decommissioning of open cycle and peak devices will decrease both permanent jobs and jobs related to construction. Since the coal and gas used in power generation is imported, jobs in fuel supply are not affected.

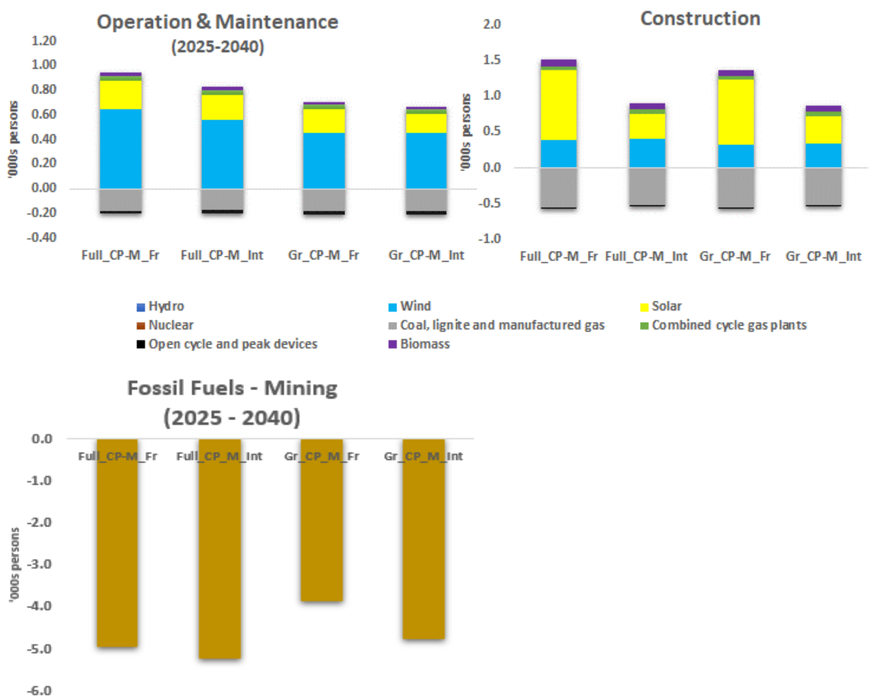
FIGURE 48: EMPLOYMENT TRENDS IN MOLDOVA ACROSS SCENARIOS



7.2.9 Ukraine

In Ukraine, the net impact on employment is positive overall, despite the reduction of solids-firing generation. Short-term employment related with the construction of the power plants increases by 1700 jobs in the fragmented market scenarios and by 1000 in the market integration scenarios. Around 500 short-term jobs will be lost due to reduced production from coal-solids power plants in all scenarios, but 750 new permanent jobs will be created in the *Full_CP-M_Fr* scenario. Also, when looking at the *Gr_CP-M_Fr* scenario there is a delay in RES investments. Most of them are made in 2030, which explains why operation and maintenance is lower than in the *Full_CP-M_Int* scenario, where all investments are made upfront. The impact on employment from the closure of coal mines is noteworthy, with 5300 jobs projected to be lost under market integration conditions.

FIGURE 49: EMPLOYMENT TRENDS IN UKRAINE ACROSS SCENARIOS



8 Redistribution of carbon revenues

The auctioning of emission allowances, whether full or gradual, implies transfer payments from emitters to the state, which unavoidably pass through to consumer prices. These transfer payments represent revenues, which can be recycled and offer possibilities for reinvestments, stimulating climate action and providing resources to address social or distributional concerns. Many studies have shown that the proper design of recycling schemes and use of these revenues can lead to a "double dividend[41]". The design of the revenue recycling scheme has to consider the characteristics and challenges of each socio-economic system at a given point in time. There is an array of possible options for the use of revenues, which must not, however, cancel emission reduction effects.

Countries may focus on addressing undesirable distributional consequences directly, through the provision of compensations (e.g. lower VAT rates, tax reductions) to assist vulnerable households and industrial sectors; and/or prioritize "positive" externalities, by putting in place enabling conditions that help emitting entities increase their flexibility and adjust more easily to carbon pricing. Possibly an additional pot of money from a dedicated modernisation and decarbonisation fund could be considered. This fund serves to support positive externalities in order to increase flexibility to undertake the necessary restructuring. Access to this funding may be possible already when cross-border trading of allowances takes place between the CPs and with the EU MS, and intensify during the period in which CPs gradually transition into the EU ETS. It would end though when CPs finally join the EU ETS.

In the EnC, carbon pricing is expected to generate an important stream of public revenues for some countries in particular (Table 28). For Ukraine, Serbia, North Macedonia, Montenegro and Bosnia and Herzegovina, the revenues are estimated to be around 1% of GDP or 2.5% of total public revenues.

TABLE 28: CARBON PRICING REVENUES (CUMULATIVE OVER THE PERIOD 2025-2040) *

	% OF PUBLIC REVENUES				% OF GDP			
	Full_CP-M_Fr	Full_CP-M_Int	Gr_CP-M_Fr	Gr_CP-M_Int	Full_CP-M_Fr	Full_CP-M_Int	Gr_CP-M_Fr	Gr_CP-M_Int
BOSNIA & HERZEGOVINA	2.5	1.6	1.8	1.1	1.0	0.6	0.7	0.4
GEORGIA	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1
KOSOVO*	1.0	0.9	1.0	0.9	0.3	0.2	0.3	0.2
MOLDOVA	0.8	0.2	0.3	0.1	0.2	0.0	0.1	0.0

[41] The double dividend hypothesis states that an environmental tax can drive both reductions in GHG emissions and improvements in economic efficiency.

MONTENEGRO	3.2	1.0	2.0	1.5	1.3	0.4	0.8	0.6
NORTH MACEDONIA	3.7	2.1	2.2	1.2	1.0	0.6	0.6	0.3
SERBIA	2.8	1.6	2.0	0.9	1.2	0.6	0.8	0.4
UKRAINE	2.3	2.2	1.6	1.5	0.7	0.7	0.5	0.5

***** *Countries with revenues lower than 0.01% are not included.*

Table 29 presents the most prominent options for using revenues from carbon pricing. These options (selected individually or in a mix) are already in use by some countries, however, it should be noted that up until today it is rare that the revenues are earmarked for specific purposes.

TABLE 29: OPTIONS TO USE CARBON PRICING REVENUES

No	Option	Scope	Features / Expected performance	Selection of countries using the option
1	**Lowering Taxation**	Private income tax, Corporate tax, VAT, Tax credits	Environmental tax or any tax that internalises an externality is considered less distortionary than other taxes. Lowering non – Pigouvian taxes can increase economic efficiency and rationalise the tax system. Attention should be given to whether the favoured activities are aligned with the overall environmental objectives.	Switzerland, British Columbia.
2	**Lowering Labour Costs**	Social security contributions	Lowering labour costs is beneficial both for employment and for boosting the competitiveness of firms. This option favours particularly labour-intensive industries.	UK, France
3	**Increasing R&D spending**	Clean energy technologies, Energy efficiency projects	Subsidizing R&D for clean energy technologies can lower the capital and transitional costs of these technologies and provide comparative advantages to the industry.	Germany, UK, France, USA, Canada,
4	**Lowering Financial costs**	Public debt, interest payments	Improving the debt profile of a country can lower interest rates and ease overall public financing.	Ireland
5	**Support Private income**	Lump sum transfers to households	Direct income transfers can support low income / vulnerable households. This demand-driven option usually has a minor impact on the economy, since consumption concerns both domestically produced and imported goods.	Switzerland, France, USA
6	**Rebates to trade**	Subsidies or tax exemptions to protect trade exposed sectors	Rebates to sectors that are carbon intensive and open to trade can support their competitiveness.	UK

	exposed firms		Implementation of this measure is subject to compliance with WTO rules.	
7	**Demand Stimulus through general spending**	Increase public consumption on infrastructure related projects	Stimulus demand is beneficial to the extent that it addresses domestic resources / production capacity.	Denmark, Finland, Ireland, Poland, Sweden and the UK
8	**Reskilling - Upskilling**	Labour force	This measure aims to address transitional issues regarding loss of employment due to shifts in production. Coal miners and other professions that will be negatively affected by changes in the energy mix will have to gain new skills. Dedicated re-skilling programmes can reduce unemployment and support household income.	USA

The way in which the adoption of different options may affect the socio-economic system of each CP depends on a multitude of factors including the specific characteristics of that economic system. The CPs with high debt to income ratios and low GDP growth rates are expected to benefit from the reduction of debt and associated interest payments. The CPs that are lagging behind in innovation and technology and that have limited capacity to produce clean energy technologies are not expected to have high return on return on R&D investments. Lowering labour costs by reducing the social security contributions of employers is expected to improve the competitiveness of firms and increase employment and household income in all CPs. Attention should be given to supporting economic activities that positively affect or are neutral to the achievement of the environmental target. Direct transfers to support household income are expected to perform low in the EnC, as most of the countries have deficits in their trade balance and in final consumption goods in particular. In other words, a significant part of the revenues may leak abroad in the form of increased imports. The performance of lower general taxes depends on the particular market distortions that each tax creates. The distortions are country-specific and researchers have not concluded as to whether reducing corporate or private taxes is better for growth and employment. In order to identify the most efficient recycling option for every CP, a mapping of their economies has been conducted using the indicators below.

TABLE 30: MAPPING RECYCLING OPTIONS WITH COUNTRY-RELATED INDICATORS

Recycling option	Indicator
Labour Cost	Labour intensity of the economy Share of social security to total labour cost Openness to trade Unemployment rate
R&D expenditures	R&D in clean energy technologies to total R&D Share of clean energy technologies in total production

Debt and financial cost	Debt ratio Interest rate payments as % of GDP Expected growth of the economy
Private Income	Vulnerable households exposed to energy and technology poverty Share of imports in total private consumption
Rebate on Firms	Carbon intensity and trade openness of firms
Demand stimulus	Public multipliers
Reskilling - Upskilling	Share of workers in coal mines and affected power plants in total labour force

As indicated in Table 29, countries with carbon pricing in place use a mix of options to recycle the revenues back into the economy. Options need to be evaluated not only according to their economic performance but also according to their social implications, not a straightforward task. In order to develop a ranking matrix by country, the Input-Output multipliers related to each option have been calculated. The recycling option with the highest multiplier ranks first. The results are presented in Table 31. On average, the best performing option is boosting the competitiveness of export-oriented firms. It is positive for trade balance and has high economic multiplier effects. Lowering labour costs and supporting household income are the next best options. Countries that have already reduced the social security contributions paid by employers, like Ukraine, are expected to benefit less, but others will gain both in terms of increasing employment and in terms of raising output. The options with the lowest performance seem to be the reduction of general taxation and the increase in public spending/demand stimulus. The public spending multiplier is low in most CPs, given the high shares of taxation and imports. However, the Input-Output multiplier approach neglects the productivity effects that the additional spending on infrastructure will have on the economy. Employment in countries with coal/lignite mines will benefit if part of the carbon pricing revenues is used to reskill/train coal mine workers.

TABLE 31: RANKING BY COUNTRY OF RECYCLING OPTIONS (BEST OPTION = 1)

Contracting Parties	Lowering Taxation	Lowering Labour Costs	Support Private Income	Support to Trade Exposed Firms	Demand Stimulus
ALBANIA	4	3	2	1	5
BOSNIA & HERZEGOVINA	2	4	5	1	3
GEORGIA	4	3	1	2	5
KOSOVO*	4	3	2	1	5
MOLDOVA	5	2	4	3	1
MONTENEGRO	5	4	3	2	1
NORTH MACEDONIA	3	1	4	2	5
SERBIA	3	4	2	1	5

UKRAINE	2	4	3	1	5

9 Conclusion and recommendations

The EnC_Carbon study has sought to identify a carbon pricing mechanism that is conducive to the swift, cost-effective, and socially acceptable decarbonisation of the power and district-heating sectors in the EnC. The study has shown that carbon pricing is a powerful policy instrument for tackling climate change, as it can curb GHG emissions in a fast and cost-effective manner, provide a clear signal to investors for RES deployment and accelerate the transition to a low-carbon economy in the EnC. Moreover, carbon pricing can offer a source of public revenues, which may be re-invested in the economy to help alleviate the financial burden on consumers, enable technological progress and fund investment in clean technologies. Notwithstanding the jobs that will be lost due to the decommissioning of thermal power plants, the study projects carbon pricing to have a positive impact on the economy and employment as a whole. Pouring investments into RES deployment will create short-term and permanent jobs in the construction, equipment and services sectors that will compensate for the ones lost due to pulling investments from solids-firing generation.

After conducting an in-depth analysis of different carbon pricing schemes and considering the market size, institutional maturity and overall state of the economy in the CPs, the study puts forward a proposal for a Cap and Trade system in the power and district heating sectors. Also, the study invites the CPs to consider adjusting existing excise taxes in fuels used in buildings and transport so as to close the gap with average tax levels in the three (3) EU MS covered by the study, if combined with existing excise taxes in these sectors. The study suggests the Cap and Trade system of each CP to merge with the EU ETS in the future. The EU ETS represents the backbone of the path to climate neutrality, a major enabling condition for emission reduction and RES uptake, further integration of the energy system and completion of the internal market.

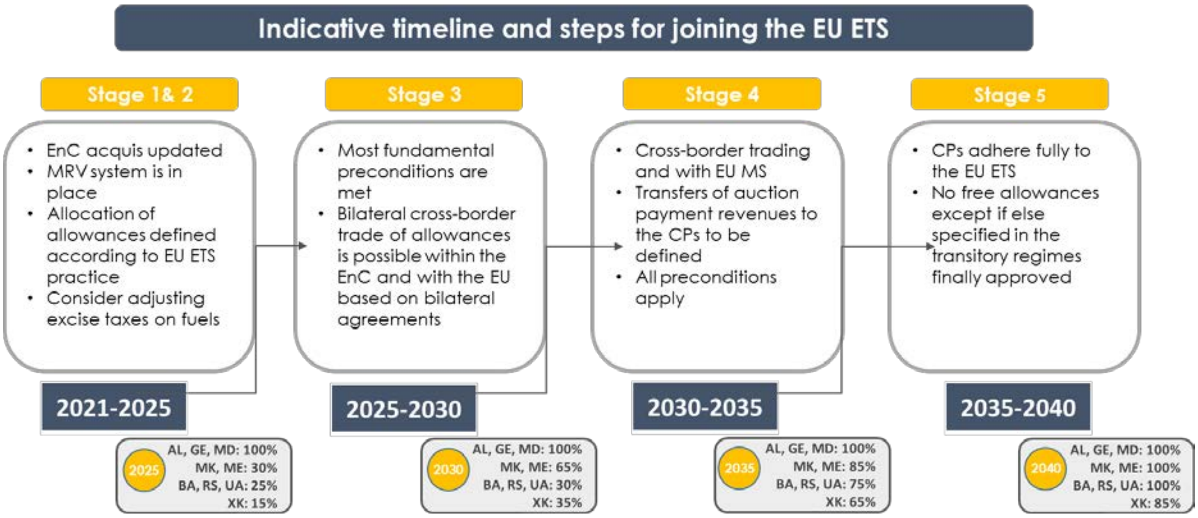
In order to assess the implications of a Cap and Trade system in the power and district heating sectors of the EnC, the study has quantified (5) five scenarios, one being the *BSL* scenario. The BSL scenario is not a strong policy option, as it rests on the assumption that carbon pricing does not apply and power and gas markets remain fragmented. Model-based projections reveal it is not sustainable either, as it maintains coal and lignite use in power generation and district heating, despite mounting costs and investor reluctance to engage in refurbishment. Under BSL trends, subsidies keep the coal sector afloat, while market fragmentation obstructs access to efficient and flexible gas and delays large-scale development of RES. Traditional exporting countries like Bosnia and Herzegovina and Serbia continue to export solids-based electricity but less than they used to, while traditional importers like Kosovo* and North Macedonia fail to diversify their power mix and continue to rely on solids-based electricity imports. CO2 emissions drop, but certainly not to the extent that would allow complying with pledges to the Paris Agreement and upcoming revision of the EnC energy and climate acquis. That said, under the BSL scenario, the energy transition in the EnC is projected to be longsome, expensive and inconsistent with the commitment to share Europe's ambition for a climate-neutral future. Further to that, the model-based projections suggest that the *BSL_CBAT* scenario is not an option for consideration either. It fails to eliminate solids from power generation and drive a sharp reduction in CO2 emissions and increases, at the same time, costs for consumers. This is because the carbon tax would apply on the entire power mix, and not just on solids, and so the impact on gas and RES is expected to be stronger, since the tax would affect resources high on the merit order.

The remaining four (4) scenarios assume different combinations of a full *vs.* gradual carbon pricing with an integrated *vs.* fragmented power and gas market. Scenarios bringing together either gradual *(Gr_CP-M_Fr)* or full *(Full_CP-M_Int)* carbon pricing with market fragmentation are foreseen to have detrimental effects on efficient gas investment, RES deployment and electricity prices. Carbon pricing theoretically favours gas as a transition fuel away from coal. Large-scale development of RES also depends on gas balancing to some extent. In both cases, the decisive enabling factor is the gas supply context. The study projects that if power and gas markets remain fragmented, the diversification and improvement of gas supply conditions is severely constrained. Meanwhile, market fragmentation forces CPs to maintain heavy emitters in operation for system purposes, which prevents high responsiveness to rising carbon costs and development of low-carbon solutions. Combined, these conditions imply highly adverse impacts on consumer prices. Besides, CO2 emissions drop only slightly more than under BSL trends. The *Gr_CP-M_Fr* scenario in particular projects poor gains in emission reduction in the medium- and long-term, which impedes the transformation of the system according to potential and makes electricity prices vulnerable to full carbon pricing at a later stage.

Conversely, model-based projections envisage that moving beyond the current state of fragmented markets towards making interconnections fully available to coupled markets and providing access to cheaper, more secure and flexible gas, allows CPs to access low-cost and carbon-free resources and their balancing facilities. In this way, CPs manage to diversify and adjust their power generation mix to a reasonably high carbon emissions price. A broad regional market and improved gas supply conditions allow investors to get positive anticipation about capital returns of new gas investment. This is particularly beneficial for balancing, RES integration, and electricity trade. A diversified power mix also results in a faster and starker CO2 emission reduction. Still though, the *Full_CP-M_Int* scenario is projected to be particularly challenging to implement, since the majority of CPs are heavily dependent on solids and cannot comply with the stringent assumptions underpinning the scenario. Pursuing full carbon pricing and market integration from 2025 will turn the thermal power plant obsolete, with immediate negative implications for supply adequacy and electricity prices. Projections point to gradual carbon pricing being enough to drive coal phase-out within a reasonable timeframe, without disproportionally affecting less flexible CPs. The study thus recommends the *Gr_CP-M_Int* scenario as the most suitable policy option, for it is: ***Effective***, enabling even the most vulnerable CPs to diversify their power mix and bring emissions down fast, without compromising security of supply; ***Cost-efficient***, allowing CPs to reduce costs through imports of low-carbon electricity and investment in RES and balancing facilities in the medium-term, preventing retail prices from rising exponentially; ***Reliable***, helping relax system constraints while enabling the increased penetration of variable RES.

Figure 50 provides an indicative timeline and action points for setting in motion the proposed carbon-pricing policy option in the EnC. A detailed overview of the stages is provided in section 4.2. The CPs are invited to adopt carbon pricing and the supporting legal and institutional framework in a coordinated manner the earliest possible, starting i.e. 2021. This involves transposing legislation related with the implementation of the EU ETS, as well as requirements of the Governance Regulation.

FIGURE 50: JOINING THE EU ETS UNDER THE GR_CP-M_INT SCENARIO



The allocation of allowances should be defined according to the EU ETS practice, supported by a sophisticated MRV scheme, including precise guidelines and detailed instructions, to ensure maximum efficiency and transparency. Robust data safeguards the integrity of the ETS system and nurtures trust among stakeholders. The allocation of allowances to industrial installations should also be defined according to EU ETS practice. Sectors facing competition from industries outside the EnC not subject to comparable climate legislation should be set to receive more free allowances and their electricity tariffs should include discounts for carbon price costs. Year 2025 represents a milestone in CP's adhesion to the EU ETS. The gradual auctioning of allowances kicks-in in each CP and cross-border trade of allowances becomes possible within the EnC and with the EU, on the basis of bilateral agreements, since CPs are not yet fully certified within the EU ETS system. Most fundamental legal and institutional arrangements, i.e. for the settlement of financial transactions, the liquidity of the market, transparency and integrity, are taking shape, while distortionary policies such as coal subsidies are eliminated. From 2030 onwards, the CPs may adhere to the

EU ETS under a transitional regime, which implies cross-border trading of allowances can take place at regional level and transfer of revenues from auction payments be defined. Once the CPs have completed the transitory phase, they become full members of the EU ETS. This means free allowances are abolished, except as otherwise provided in the approved transitory regimes.

10 Appendix

10.1 Electricity and heat pricing

A detailed explanation of how the modelling projects the evolution of electricity prices for the EnC CPs is provided below:

The electricity and heat modelling of the CPs represents the optimum capacity expansion and the unit commitment algorithm for the interconnected power system of the region simultaneously. The optimization seeks to minimize total system costs, including fuel, taxation, non-fuel carriable, fixed and capital (investment) expenditures, over a time horizon until 2040. The cost function also includes penalty costs for load, renewables, and reserve curtailment. The optimization constraints include the balancing of electricity demand, considering it as given, and various power reserve types, which form the ancillary services. Technical restrictions on power plant operation include maximum power capacity, minimum stable generation capacity, minimum up and down durations, maximum ramping up and down rates and the possibilities to supply ancillary services. The variable renewable technologies follow a predetermined hourly production pattern. Hydropower plants have water reservoirs and are subject to constraints related to hydrological cycles and storage possibilities. For some fuel types, including biomass, lignite and gas, maximum potential restrictions apply in the form of cost-potential curves with ascending slopes. The evolution of power plant capacities stems from decisions on decommissioning, refurbishment and new commissioning, which are endogenously part of the optimization. The flows over interconnectors are subject to net transfer capacity restrictions, technical capacities of transmission lines and the Kirchhoff's laws expressed in DC-linear terms. Finally, the model also includes novel storage technologies, such as batteries and hydrogen-based power-to-X, for which investment and operation are endogenous together with hydro pumping capacities. The output of the optimization includes the hourly generation by the power plants, power charging and discharging of storage devices, reserve power for ancillary services, flows over interconnectors, and capacity-related decisions for investment, refurbishment, and decommissioning. Similar representations concern heat production via heat-only production plants and via units that cogenerate heat and electricity. The load patterns of electricity and heat are different and are synchronous in the hourly operation of production facilities as resulting from the model solution.

After the solution of the model by an optimization algorithm, the modelling calculates costs of electricity and heat, including annual equivalent capital costs of plants and storage facilities, with consideration of not yet amortized investment cost of old plants, fixed operation and maintenance costs, variable non-fuel costs, taxation costs, including, auctioning payments, and fuel costs. The sum of these costs represents the total cost of electricity (and heat, separately) production. Obviously, these costs do not include grid costs and other fees and levies. The model applies an electricity pricing method to calculate retail electricity prices on average and by sector. The method uses the Ramsey-Boiteux approach. A customer type first bears a tariff that reflects long-term system marginal cost determined by a matching of consumer's hourly load profile with a corresponding power generation profile of a portfolio of plants and other resources. The method compares total revenues based on tariffs that reflect long-term marginal costs to total costs of power generation and the gap, which usually is positive (i.e. missing money), justifies an additional charge determined by the inverse of price-elasticity values of the customer types, according to the Ramsey approach. In the end, the revenues from consumer tariffs recoup all power production costs precisely.

Obviously, it is as if the total average costs of power production determine the average consumer tariff. The total average cost pricing is inclusive of all kinds of expenditures incurred in power production and reserves, including capital costs and the cost of old plants remaining in the system. As the intertemporal optimization inherits capacities from the past and as the horizon stops after twenty years only, the capacity mix is not entirely optimal; thus, stranded costs may occur, and prices include them. However, average cost pricing of electricity cannot capture scarcity rents for resources, such as plants and other facilities helping to meet demand and reserves, if scarce of course.

Given that capacity expansion is endogenous, scarcity of resources is not common, especially in the projection for the longer-term, unless resource restrictions apply which obstruct the achievement of an optimal capacity mix. In reality, scarcity rent can occur, mainly in the short-term and less often in the medium and long-term, being a symptom of market power. Yet in the modelling of intertemporal optimization with capacity expansion, rents driven by market power are not possible.

The model does not calculate the wholesale prices of electricity but only retail prices. According to standard practices, the term wholesale prices refers to day-ahead market clearing prices, which may include the whole system or a part of it, depending on market design. With few exceptions (notably Greece and Ireland in the EU), such wholesale markets do not include demand for reserve and do not consider technical restrictions of plant operation. In this case, wholesale market clearing prices reflect the variable cost of the most expensive power plant used to satisfy demand. In the intra-day markets and the procurement of ancillary services, different market-clearing prices occur. The total cost of power and reserve procurement by load supply entities is the sum of costs arising in the market stages. Under market coupling arrangements, the day-ahead wholesale prices are the same in all coupled markets in the absence of congestion in the interconnectors; otherwise, the wholesale prices are different. The same happens in intra-day and balancing markets when coupled.

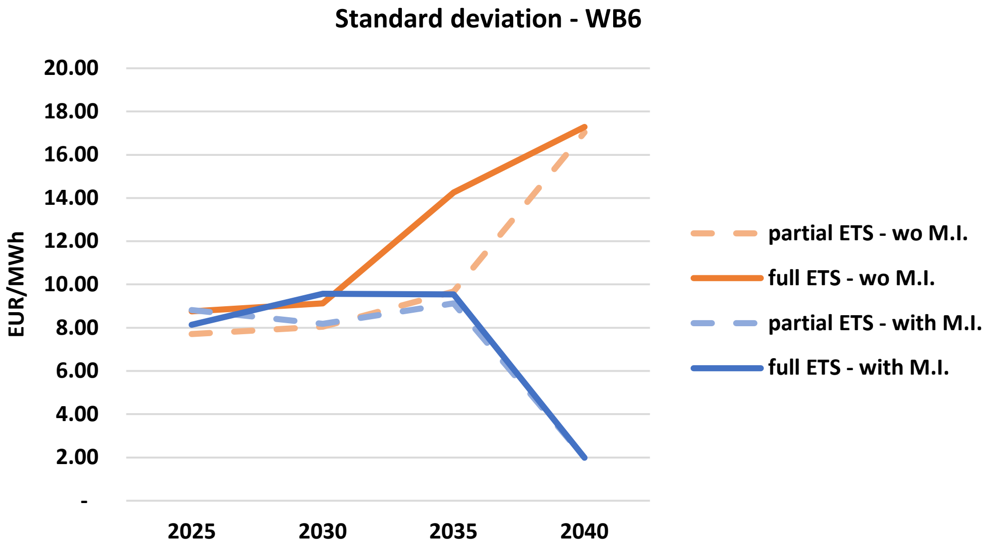
It is essential to consider that day-ahead wholesale electricity prices do not coincide with retail prices. At least three reasons are worth mentioning. First, renewables are not part of the day-ahead wholesale market and market clearing prices tend to decrease when renewables increase, although the renewables plants need to recover capital and operation costs based on revenues from consumer prices.

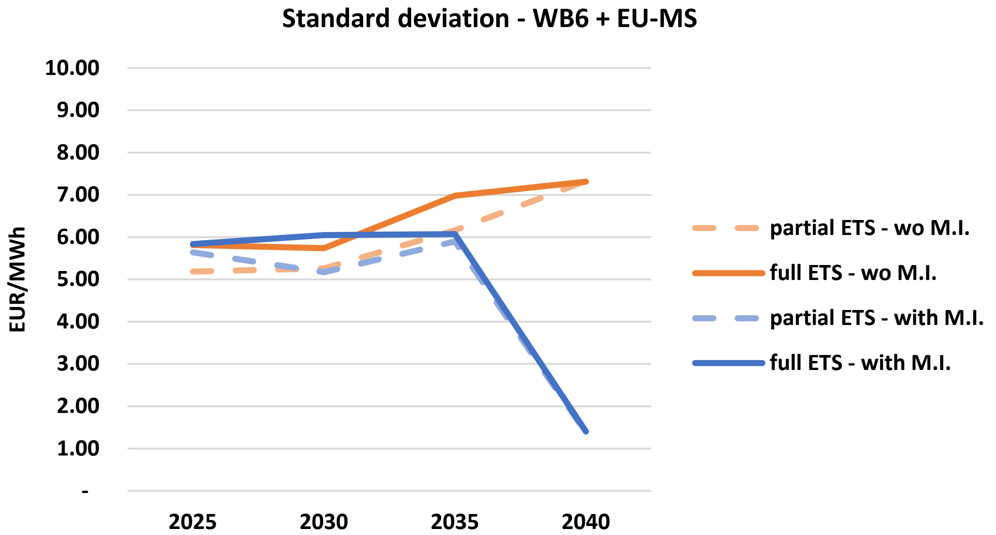
Second, balancing and reserves entail costs and probably scarcity rents, which are not part of the day-ahead wholesale market. Third, the entire power system may include capacities not yet amortized or plants in reserve for which electricity suppliers may succeed recouping fixed costs from consumer prices. All three reasons would imply that day-ahead wholesale clearing prices are on average lower than retail prices. However, it is possible to see the inverse in reality, at least in the short-term. Scarcity rents (possible when market power exists) may imply wholesale market clearing prices, both in day-ahead and balancing, to be excessively high and thus higher than average system costs, hence higher than average customer prices.

In impact assessment of policy options, as well as in long-term planning, an essential criterion is cost impact on final consumers of energy. This is why the model emphasizes on consumer prices in the carbon pricing study. The method is exactly like the impact assessment approaches followed by numerous studies of the European Commission using the PRIMES model. As explained above, the wholesale market prices, taken alone, are not indicative of the cost impacts on final consumers. Nonetheless, below we exemplify a method for calculating wholesale prices based on the scenarios quantified using the model for the CPs to check whether they are consistent with intuition about the integration of markets.

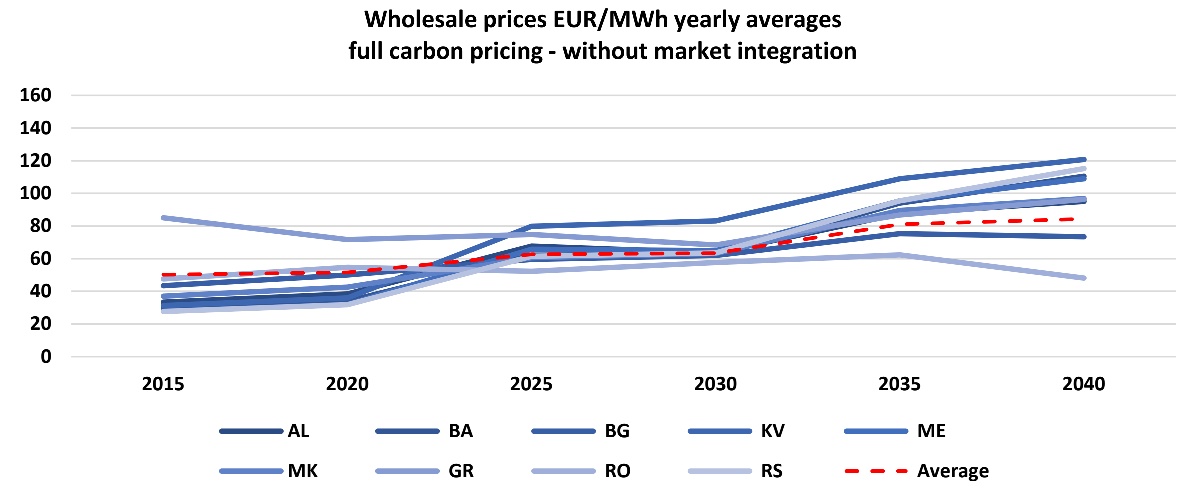
The approach consists of re-running the solution of the optimization model after considering the capacity-related endogenous variables and the provision of reserves as fixed to their values in the projection by scenario. In this manner, the cost structure includes variable costs only and the optimization is equivalent of the determination of the merit order of plants according to their marginal costs. The model is still slightly more complicated than a pure-energy wholesale market, such as the day-ahead, because it includes technical operation constraints of the plants, the dispatching of storage devices and penalties on curtailment. As under market coupling, the model includes interconnection flows endogenously. The wholesale market prices are dual to the demand constraint of the optimization model and are on an hourly basis. We calculate yearly average wholesale market prices as a weighted sum using hourly load as weight.

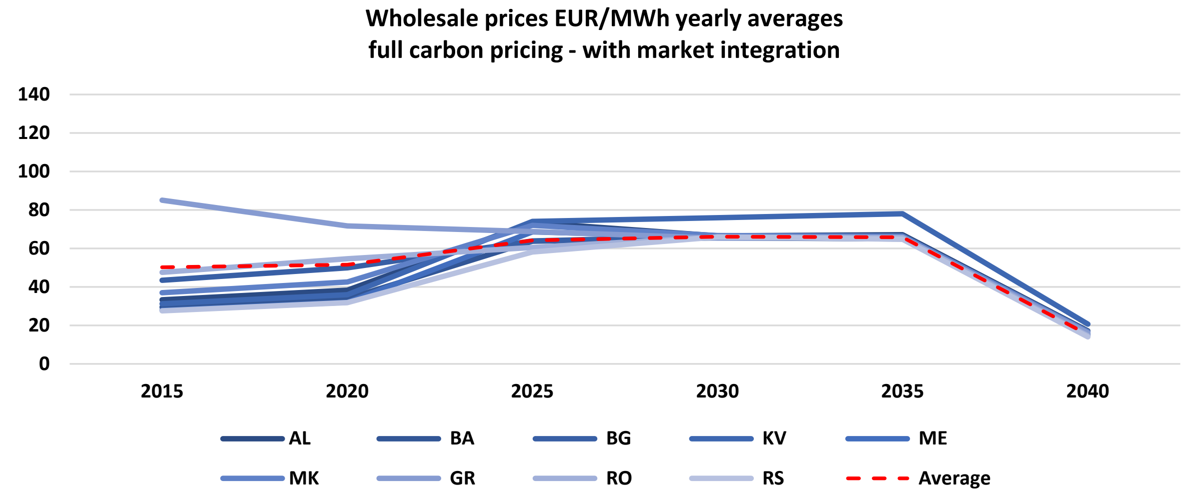
The section below shows a summary of the yearly average wholesale market prices by scenario. To check whether the model-based estimation of wholesale prices is consistent with the hypothesis of market integration, which is part of some of the scenarios, we show below calculations of standard deviation of country-specific wholesale prices. The standard deviation applies on the South-East European area, which comprises the Western Balkan countries plus Romania, Bulgaria and Greece.





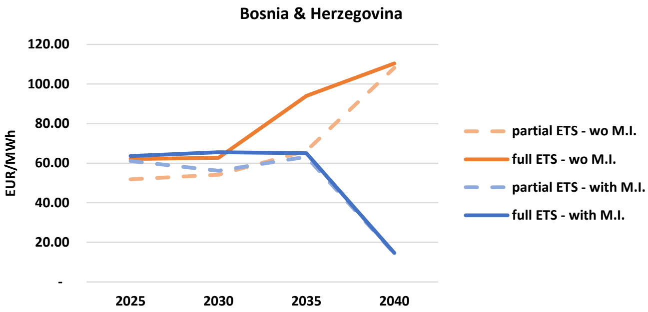
The figures above clearly show that in the market integration scenarios the standard deviation of wholesale market prices decrease over time, while it increases in the scenarios that assume no market integration. The striking difference in the trends occurs irrespective of the assumptions about carbon pricing, i.e. full or gradual. The divergence of the trends is higher from 2030 onwards, and is related to the increase in the renewables. Market integration is particularly important when renewables increase beyond a certain share in power generation because of the benefits from sharing balancing resources. This brings down reserve costs, smooths out operation of plants and helps limiting wholesale market pricing within reasonable ranges. The results confirm the importance of the sharing of balancing resources in the longer term thanks to market integration.

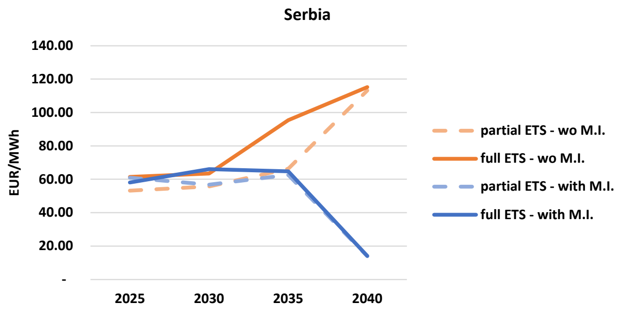


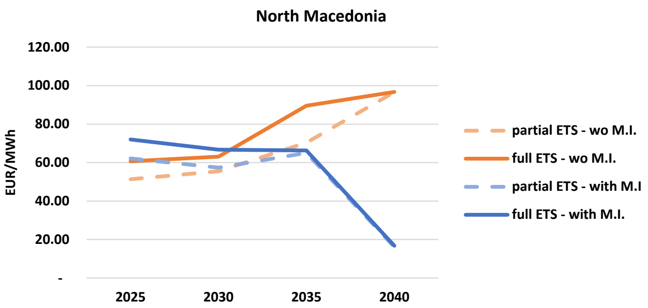


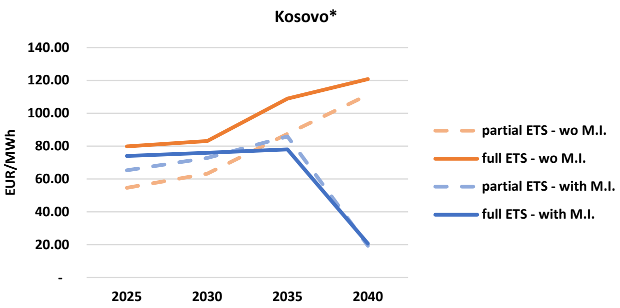
The figures above illustrate the same findings of the modelling analysis. The graphic below that assumes market integration shows stable and decreasing wholesale market prices and at the same time an obvious convergence across the countries. The opposite, including a divergence, is evident in the graphic on top, which assumes no market integration. Both apply carbon pricing fully.

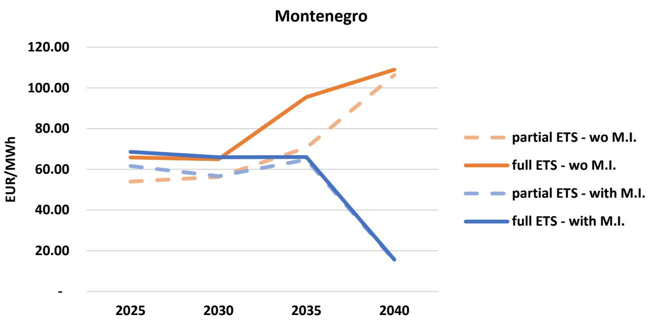
The following figure shows wholesale market prices per country.

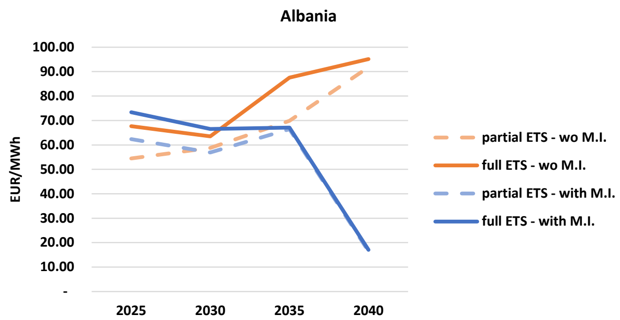

Bosnia & Herzegovina
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.

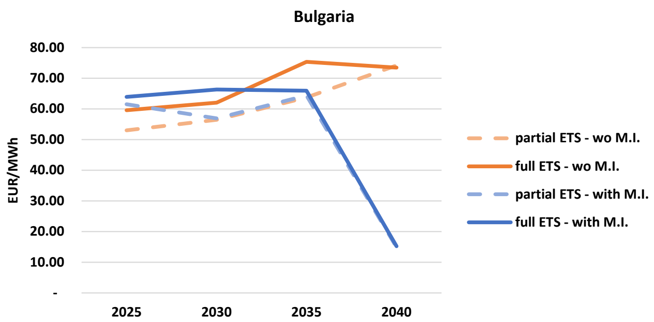

Serbia
140.00
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.

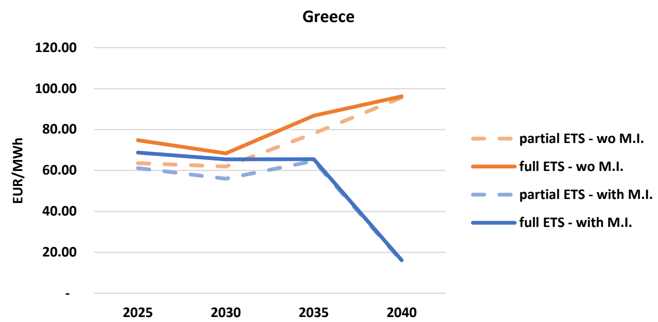

North Macedonia
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I
full ETS - with M.I.

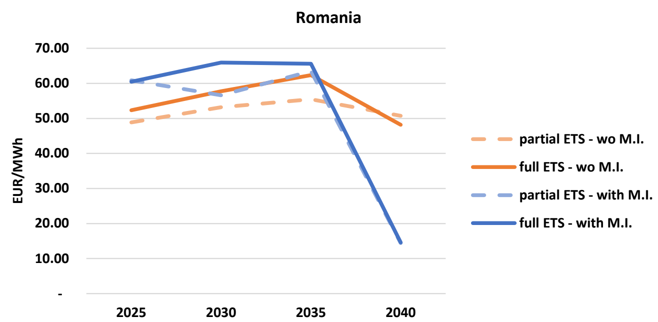

Kosovo*
140.00
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.


Montenegro
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.


Albania
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.


Bulgaria
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.


Greece
120.00
100.00
80.00
60.00
40.00
20.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.


Romania
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
EUR/MWh
2025
2030
2035
2040
partial ETS - wo M.I.
full ETS - wo M.I.
partial ETS - with M.I.
full ETS - with M.I.

Average electricity prices in the wholesale market

Bosnia & Herzegovina		2015	2020	2025	2030	2035	2040
BA	Baseline	29.55	33.98	58.82	52.35	34.59	40.41
BA	partial ETS - wo M.I.	29.55	33.98	51.89	54.21	66.25	108.17
BA	full ETS - wo M.I.	29.55	33.98	62.10	62.72	94.05	110.47
BA	partial ETS - with M.I.	29.55	33.98	61.09	56.20	63.22	14.40
BA	full ETS - with M.I.	29.55	33.98	63.69	65.57	65.00	14.61
Serbia		2015	2020	2025	2030	2035	2040
RS	Baseline	27.67	31.82	59.49	53.16	35.31	41.34
RS	partial ETS - wo M.I.	27.67	31.82	53.15	55.67	66.32	113.18
RS	full ETS - wo M.I.	27.67	31.82	61.45	63.46	95.43	115.18
RS	partial ETS - with M.I.	27.67	31.82	60.89	56.82	62.60	13.95
RS	full ETS - with M.I.	27.67	31.82	58.12	66.03	64.79	14.09
North Macedonia		2015	2020	2025	2030	2035	2040
MK	Baseline	37.02	42.57	55.85	50.15	32.22	35.61
MK	partial ETS - wo M.I.	37.02	42.57	51.35	55.49	70.38	96.58
MK	full ETS - wo M.I.	37.02	42.57	60.67	63.13	89.55	96.74
MK	partial ETS - with M.I.	37.02	42.57	62.15	57.36	65.09	16.14
MK	full ETS - with M.I.	37.02	42.57	71.99	66.69	66.35	16.77
Kosovo*		2015	2020	2025	2030	2035	2040
XK	Baseline	31.30	35.99	60.83	53.21	38.78	48.67

XK	partial ETS - wo M.I.	31.30	35.99	54.58	63.22	87.52	111.20
XK	full ETS - wo M.I.	31.30	35.99	79.85	83.09	108.91	120.79
XK	partial ETS - with M.I.	31.30	35.99	65.35	72.82	85.89	19.44
XK	full ETS - with M.I.	31.30	35.99	74.00	76.00	78.00	20.68
Montenegro		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
ME	Baseline	27.83	32.00	60.36	53.58	36.61	43.56
ME	partial ETS - wo M.I.	27.83	32.00	54.04	56.26	70.62	106.38
ME	full ETS - wo M.I.	27.83	32.00	65.81	64.95	95.49	109.00
ME	partial ETS - with M.I.	27.83	32.00	61.61	56.66	64.79	15.23
ME	full ETS - with M.I.	27.83	32.00	68.57	65.95	66.06	15.64
Albania		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
AL	Baseline	33.38	38.38	60.19	54.04	37.22	45.62
AL	partial ETS - wo M.I.	33.38	38.38	54.48	58.77	69.89	91.79
AL	full ETS - wo M.I.	33.38	38.38	67.67	63.49	87.58	95.15
AL	partial ETS - with M.I.	33.38	38.38	62.39	56.95	66.45	16.45
AL	full ETS - with M.I.	33.38	38.38	73.40	66.55	67.13	17.10
Ukraine		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
UA	Baseline	41.14	42.16	38.91	42.16	15.54	22.20
UA	partial ETS - wo M.I.	41.14	42.16	48.11	37.92	21.54	22.77
UA	full ETS - wo M.I.	41.14	42.16	42.90	27.16	23.67	22.80
UA	partial ETS - with M.I.	41.14	42.16	29.86	37.40	21.95	10.96

UA	full ETS - with M.I.	41.14	42.16	31.44	18.38	20.20	10.90
Bulgaria		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
BG	Baseline	43.49	50.01	56.09	53.87	35.91	44.65
BG	partial ETS - wo M.I.	43.49	50.01	52.97	56.45	63.72	74.14
BG	full ETS - wo M.I.	43.49	50.01	59.53	61.99	75.35	73.44
BG	partial ETS - with M.I.	43.49	50.01	61.51	56.88	64.34	14.91
BG	full ETS - with M.I.	43.49	50.01	63.90	66.28	65.90	15.23
Greece		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
GR	Baseline	85.09	71.76	66.15	58.85	44.13	61.77
GR	partial ETS - wo M.I.	85.09	71.76	63.61	61.89	78.13	95.61
GR	full ETS - wo M.I.	85.09	71.76	74.79	68.34	86.78	96.24
GR	partial ETS - with M.I.	85.09	71.76	61.10	55.99	64.66	15.69
GR	full ETS - with M.I.	85.09	71.76	68.76	65.44	65.53	16.18
Romania		**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
RO	Baseline	47.55	54.68	50.90	51.89	32.54	38.82
RO	partial ETS - wo M.I.	47.55	54.68	48.87	53.22	55.45	50.75
RO	full ETS - wo M.I.	47.55	54.68	52.32	57.74	62.34	48.19
RO	partial ETS - with M.I.	47.55	54.68	60.89	56.60	63.53	14.42
RO	full ETS - with M.I.	47.55	54.68	60.48	65.94	65.63	14.63

10.2 Excise taxes

TABLE 32: EXCISE TAXES IN THE ENC REGION PER UNIT OF ENERGY (TOE)

In EUR	Gasoline	Diesel	LPG	Kerosene	Fuel oil	Heating oil	Nat. Gas	Coal

	(per toe)	(per toe)	(per toe)	(per toe)	(per toe)	(per toe)	(per toe)	(per toe)
ALBANIA	653	592	112	192	31	347	-	-
NORTH MACEDONIA	445	224	138	218	38	60	-	-
KOSOVO*	457	414	262	180	26	175	-	-
MONTENEGRO	584	403	216	187	21	140	-	6
BOSNIA & HERZEGOVINA	484	409	354	183	24	267	-	-
SERBIA	469	290	220	151	28	295	-	-
UKRAINE	296	161	0	0	0	0	-	1
GEORGIA	400	227	276	190	21	185	92	-
MOLDOVA	432	165	374	172	27	167	397	-
BULGARIA	461	380	304	397	21	386	27	13
ROMANIA	474	394	237	572	17	400	170	13
GREECE	889	472	751	493	40	480	92	13

TABLE 33: EXCISE TAXES IN THE ENC REGION PER UNIT OF EMISSIONS (TCO2)

In EUR	Gasoline (per t CO2)	Diesel (per t CO2)	LPG (per t CO2)	Kerosene (per t CO2)	Fuel oil (per t CO2)	Heating oil (per t CO2)	Nat. Gas (per t CO2)	Coal (per t CO2)
ALBANIA	225	191	42	64	10	113	-	-
NORTH MACEDONIA	153	72	52	73	12	19	-	-
KOSOVO*	158	134	99	60	8	57	-	-
MONTENEGRO	201	130	82	63	6	46	-	1.6
BOSNIA & HERZEGOVINA	167	132	134	61	7	87	-	-
SERBIA	162	93	83	51	9	96	-	-
UKRAINE	102	52	0	0	0	0	-	0.34
GEORGIA	138	73	104	63	6	60	39	-
MOLDOVA	149	53	141	57	8	55	169	-
BULGARIA	159	122	115	132	6	126	11	3.46
ROMANIA	163	127	90	191	5	130	73	3.46
GREECE	306	152	284	165	12	156	39	3.46

10.3 Sources of data

A list of sources for each category of data used for preparing the EnC_Carbon study is presented below.

For power plants and RES investment

- Platts database
- Data from the TSOs and regulatory authorities by country
- Data from the companies
- Various commercial databases
- Online research particularly regarding plant operation, construction etc.
- Final check of sums by technology and comparison to various sources and reports
- National plans for RES, reports by international organizations
- RES support schemes: surveys published by the European Commission (available online)

For energy balances, GDP, population

- EUROSTAT

For energy prices

- ENERDATA

- International Energy Agency
- EUROSTAT and national statistical offices

For the split of energy consumption of households by use

- Surveys submitted to EUROSTAT
- ENERDATA
- National energy efficiency reports
- TIMES model databases for countries that TIMES has been calibrated. Following this, a comparison with E3M calibrations from some years ago in PRIMES is performed, which includes adjustment and fine-tuning based on expertise. Same methodology applied for the services sector, industry and transport (for the split of energy by use).

Transport activity data

- EUROSTAT transport pocket book database
- Data from national statistical offices
- PRIMES model techniques for calibration and filling the gaps of statistical data

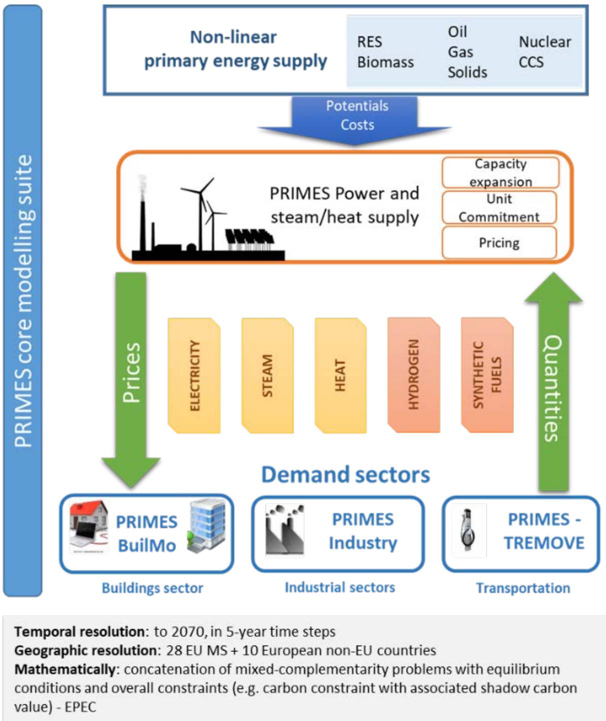
Industrial activity data

- National statistical offices
- PRODCOM database
- US Geological Surveys
- UN databases
- Industrial associations

Dwellings and living conditions

CENSUS databases

10.4 The PRIMES Energy System Model



The PRIMES (Price-Induced Market Equilibrium System) is a large-scale applied energy system model that provides detailed projections of energy demand, supply, prices and investment to the future, covering the entire energy system including emissions. The distinctive feature of PRIMES is the combination of behavioural modelling (following a microeconomic foundation) with engineering aspects, covering all energy sectors and markets. The model has a detailed representation of policy instruments related to energy markets and climate, including market drivers, standards, and targets by sector or overall (over the entire system). It handles multiple policy objectives, such as GHG emission reductions, energy efficiency and renewable energy targets, and also provides a pan-European simulation of internal markets for electricity and gas. PRIMES offers the possibility of handling market distortions, barriers to rational decisions, behaviours, as well as market coordination issues and includes a complete accounting of costs (CAPEX and OPEX) and investment expenditure on infrastructure needs. PRIMES is designed to analyse complex interactions within the energy system in multiple agents – multiple markets frameworks. Decisions by agents are formulated based on a microeconomic foundation (utility maximisation, cost minimisation and market equilibrium) embedding engineering constraints, behavioural elements and an explicit representation of technologies and vintages and optionally perfect or imperfect foresight for the modelling of investments in all sectors. PRIMES is well-placed to simulate medium and long-term transformations of the energy system (rather than short-term ones) and includes the nonlinear formulation of potentials by type (resources, sites, acceptability etc.) and technology learning.

The full suite comprises the following models:

- **PRIMES BuiMo residential and services model**: new model with a high-resolution representation of the housing and office building stock, embedded in an economic-engineering model of multi-agent choice of building renovation, heating system and equipment/appliances by energy use
- **PRIMES-Industry model**: recently enhanced version of the very detailed industrial model that includes a high-resolution split of industrial consumption

by sector and type of industrial process and now includes the possibility of using hydrogen and synthetic fuels directly, as well as extended possibilities of electrification and the possible emergence of non-fossil hydrocarbon feedstock in the chemicals

- **PRIMES Biomass supply model**: detailed biomass supply model that includes land-use constraints, many types of biomass and waste feedstock, sustainability regulation, and endogenous learning and industrial maturity of a large number of potential biomass to biofuels conversion technologies; recently enhanced in the linkage with the IIASA models that handle LULUCF and forestry, as well as linkage with the agricultural model CAPRI
- **PRIMES Electricity and heat/steam supply and market model**: fully new model version which includes the hourly unit commitment model - with a pan-European market simulation over the grid constraints and detailed technical operation restrictions - the long-term power system expansion model, the costing and pricing electricity and grid model, the integration of heat supply and industrial steam supply with synchronised hourly operation
- **PRIMES Gas supply and market model**: a stand-alone model representing in detail the gas supply and infrastructure in the Eurasian and Middle-East area and the internal European market of gas within an oligopoly model embedding engineering gas flow modelling
- **PRIMES new Fuels and storage model** covering hydrogen, synthetic fuels, power-to-X, CO_2 capture from the air and biogenic, CCS/CCU and process-emissions modelling to enhance and perform sectoral integration aiming at simulating a zero-CO_2 system
- **PRIMES IEM model**: a simulation tool for the internal energy market; it aims to simulate in detail the sequence of operation of the European electricity markets, namely the day-ahead market, the intra-day and balancing markets and finally the reserve and ancillary services market or procurement
- **PRIMES-TREMOVE transport model**: recently enhanced to include linkage to synthetic fuels and hydrogen and to detailed spatial projections of transport activity and route assignment by the forthcoming TRIMODE model (http://www.trt.it/en/PROGETTI/trimode_project/)

10.5The PRIMES Internal Electricity Market Model

The PRIMES-IEM model solves a mathematical programming problem formulated as an integer optimisation problem, under demand and system constraints, including the provision of ancillary services, interconnection possibilities and technical restrictions of the cyclical operation of the power plants. The merit-order dispatching of power plants and the wholesale market clearing depend on bidding behaviours by power plants, which are endogenously estimated by the model, reflecting fuel costs and competition strategies of participants. The modelling approach adopting a simultaneous representation of the merit-order of power plants, the system reserve constraints and the wholesale market constitutes an accurate modelling of a well-functioning electricity market independently of the particular market arrangements and codes that prevail. A market under perfect competition would lead to a least-cost structure of power generation, including the provision of system reserves independently of the market arrangements. The model determines the power mix and the prices as if conditions of perfect competition prevailed. This estimation is useful as a steady-state long-term trend for analysing policies and strategies. However, this approach has no forecasting power as it ignores market distortions.

The model simulates in a single-shot, i.e. simultaneously, the sequence of wholesale markets, i.e. day-ahead, intra-day and balancing, including the transactions performed bilaterally, outside the organised markets. As mentioned in the previous paragraph, although the markets are different – spot *or* forward, day-ahead *or* real-time, for energy *or* ancillary services – their total outcome would not differ from a single-shot simulation if they operate under perfect competition. It is worth noticing, however, that the modelling is deterministic and ignores stochastic events that may cause cost-rising deviations. To remedy this omission, the model includes the way of meeting the demand for system services and reserves, which constitute resources that the system employs to manage the uncertainties. The model also assumes that the agents are operating in the market act under perfect foresight and full information. Thus, they do not distinguish between spot and forward markets concerning a decision under uncertainty and risk hedging.

Based on model results for the wholesale markets and the total generation costs, the electricity-pricing algorithm applies a Boiteux and Ramsey methodology to estimate end-user electricity prices by consumer category. The calculation of electricity prices assumes that the sellers recover operation, fixed and capital costs of electricity generation under perfect competition conditions, which allow pricing electricity on average according to the long-run marginal system costs (i.e. total marginal cost of optimal system expansion). The projected electricity prices differ by sector reflecting different load factors of electricity demand, scale economies and price-elasticities.

The Primes-IEM market simulator runs for all years of the projection period 2019-2040 on an hourly basis per year. It is assumed that the wholesale market is a pay-as-clear auction where suppliers and demanders submit stepwise price-quantity bids. Thus, the market-clearing prices result from the equilibrium between aggregate demand and supply. The determination of the price biddings of the power plants is endogenous and reflects consideration of competitors' bidding at times of power scarcity. The model bases the simulation of the market on the minimisation of the total cost of meeting the demand for electricity and ancillary services, meant from the perspective of the buyer of energy or service. In perfect competition market conditions, we assume that in principle power plants bid at plant's marginal costs, which depend on fuel costs, emission costs and other non-fuel variable costs. A reasonable mark-up is assumed to apply by price-making bidders at scarcity times. Fixed costs do not intervene in the bidding. The generators compete for providing energy and reserves, offering them simultaneously from a technical perspective but pricing them differently. The market algorithm co-optimises energy and reserve provisions. The contribution of the power plants to system reserves and services depends on the technical possibilities of the plants. The optimality of the merit-order dispatching simultaneously depends on endogenous price bids and technical restrictions of the power plant operation as needed to meet the demand for electricity and reserves. Meeting demand for electricity and at the same time requirements for ancillary services is subject to several operational restrictions of the power plants, including their maximum and minimum technical operation capacity, the ramping capabilities, start-up and shut-down costs, the fuel cost curves and the minimum up and downtimes.

The consideration of system and plant operation constraints in the optimisation of the wholesale market implies higher market clearing prices compared to the outcome of pure energy day-ahead markets, i.e. those that only optimise electricity generation. In reality, intra-day and balancing markets would add expenses on top of pure-energy markets to cover costs of generation resources dedicated to the provision of reserves and for covering deviations. If competition is inefficient in the day-ahead market, actors will ignore the events and system reserve requirements when submitting their offers to the day-ahead market. Therefore, the schedules would be inefficient from a systems perspective, and then real-time and balancing markets would require additional resources and would employ generation resources differently than scheduled by the day-ahead market planning. In this case, additional costs would arise due to the discrepancy between expectations in day-ahead and the outcomes in real-time. The model assumes that eventually such discrepancies could be avoided in well-functioning markets. Thus, by co-optimising energy and reserves, the model accounts for the costs of the entire sequence of wholesale markets by running a single-shot optimisation algorithm.

The competition between generators takes place in reality both in wholesale markets and through bilateral contracts for economic differences concluded between integrated generation-supply entities and customers. The bilateral contracts, when handled as block-orders or nominations by dispatchers, imply that wholesale markets cover only the non-declared part of generation and load. Independently of the variety of such market arrangements and practices, economic theory suggests that a well-functioning electricity market in equilibrium will balance exactly at the same prices and will determine the same least-cost generation mix whether it operates as a mandatory wholesale market or through purely bilateral contracts. Also, block-order bidding would be of economic interest compared to bidding separately by power plant only when dominant firms exercise anti-competitive behaviours to push competitors out of the markets. Otherwise, from a private perspective, economic optimisation is superior when supply to customers is derived from a perfectly cost-optimised merit-order dispatching schedule rather than from costlier partly defined portfolios. Reflecting these considerations, the model does not need to simulate bilateral contract markets, as it is sufficient to simulate only a perfectly operating wholesale market. Under such conditions, it can be seen as equivalent to bilateral contracts and mixed practices.

Hydropower is exogenously scheduled and is subject to water scarcity, which is optimised on an annual basis for water reservoir plants and an hourly basis for run-of-river power plants. Pumped-storage operation is endogenous. The model assumes daily storage cycles. Pumping extraction and injection is endogenous, based on hourly system price arbitrage, depending on capacities. Hydropower plants with a reservoir submit offers at peak load times slightly above prices offered by mid-merit gas plants (e.g. CCGT with medium efficiency).

Hourly availability of variable RES is considered as given – in the sense that it is not stochastic. The model takes as exogenous inputs the evolution of power plant capacities, reserve requirements, electricity demand, RES capacity and system control parameters, the possibility of nominating packages of load and generation. The model also includes economic functions for possible curtailment (load, RES etc.) and constraints related to operational limitations. The model is deterministic, ignoring any deviation or adjustments, which may occur in real-time system operation. The evolution of power plant capacities in the period 2020-2030, including the differences by scenario, is based on independent studies performed using the PRIMES model for the European Commission.

The simulator's database uses as input data:

- Time-series of load demand
- Power plant capacities and heat rates
- Generation by vRES connected to all voltage systems and production by hydro units
- Must-take CHP generation
- Projections of demand for electricity and renewable penetration
- Technical and costing parameters per power plant
- Availability of power plants
- Time series on fossil fuel prices
- Demand for ancillary services

Must-take CHP generation is considered for CHP plants whose operation is driven by heat supply, namely industrial CHP units and exclusively district heating plants. Other units producing heat as a by-product (large CHP units) are treated in the model as any of the other power plants. The simulator assumes priority dispatching for certain power generation technologies. In particular, CHP generation of industrial CHP units, exclusively district-heating plants and all RES generation dispatch with priority. To simulate priority dispatch, the model assumes zero prices for the bids for fixed hourly amounts of production by the concerned capacities.

The main outputs of the model can be summarised as follows:

- Hourly operation per power plant and year for the projection period 2018-2030
- Provision of ancillary services per power plant in the same period
- Hourly electricity balance including generation, net imports, production by RES, hydro production and pumping
- Hourly estimation of the system marginal price in the day-ahead market during 2019-2030
- Estimation of hourly prices for the provision of ancillary services
- Revenues and costs of the power plants, hourly and annually, with optional inclusion of fixed operation and maintenance costs