Impact assessment for the establishment of a regional Emission Trading System in Energy Community Contracting Parties – NEAR.A3

NEAR/A3

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1. Introduction

1.1. Policy context

Recent years have been marked by landmark policy developments in the European Union (EU) and globally. Limiting global warming to 1.5 degrees Celsius in line with the Paris Agreement requires deep decarbonisation of all carbon-emitting sectors. This will require a rapid and far-reaching transition across all sectors and systems to secure a liveable and sustainable future for all (IPCC, 2023).

In this context, the European Climate Law[1] sets out the legally binding target to achieve climate neutrality by 2050. The law also includes the intermediate binding EU target of reducing net Greenhouse Gas Emissions (GHGs) by at least 55% (compared to 1990 levels) by 2030 and setting a climate target for 2040 within six months of the first global stocktake under the Paris Agreement.

In parallel with the profound changes in the climate and energy policy EU landscape, the transition towards decarbonised economies is progressing across all Contracting Parties (CPs) of the Energy Community (EnC), as it has been clear that Europe's transition to climate neutrality can be effective if the whole region and immediate neighbourhood raises its climate ambition. The EnC acquis has undergone several updates in recent years, reflecting that the CPs keep pace with the EU policy developments. In 2020, the Western Balkan 6 (WB6) countries agreed and signed the Action Plan[2] to implement the Sofia Declaration[3] on the Green Agenda during the Western Balkans Sofia Summit, committing to achieve climate neutrality by 2050. The Green Agenda for the Western Balkans, part of the EU's Green Deal plan, aims to help the WB6 quickly align with the EU's Climate Law. Part of the agenda and the Action plan focused on introducing carbon-pricing instruments and/or aligning with the EU-ETS to encourage the decarbonisation of the region.

The adoption by the EnC Ministerial Council of the Decarbonisation Roadmap[4] of the EnC in 2021 reiterated the commitment of all EnC CPs to work towards the energy transition and the achievement of the Green Deal objectives. The first step of the Decarbonisation Roadmap was the incorporation of the Governance Regulation and the Energy Efficiency (EE) and Renewables Directive, pledging to reduce emissions, boost energy efficiency measures and speed up the uptake of renewable energy. This first step was achieved in 2022 with the adoption by the EnC Ministerial Council of the legally binding 2030 climate and energy targets, which provides the cornerstones for the design of the National and Energy Climate Plans (NECPs) for the EnC CPs, which were due by 30 June 2024.

The EnC took important steps as the 2022 Ministerial Council adopted several regulations[5] to monitor, report and verify the greenhouse gas emissions and associated legal acts. This crucial step enables EnC CPs to obtain a precise and verified overview of the total emissions from energy and other

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[1] *REGULATION (EU) 2021/1119 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law')*

[2] *Action plan for the implementation of the Sofia Declaration on the Green Agenda for the Western Balkans 2021-2030,* https://www.rcc.int/docs/596/action-plan-for-the-implementation-of-the-sofia-declaration-on-the-green-agenda-for-the-western-balkans-2021-2030

[3] *Sofia Declaration on the Green Agenda for the Western Balkans, November 2020,* https://www.rcc.int/docs/546/sofia-declaration-on-the-green-agenda-for-the-western-balkans-rn

[4] *Decarbonisation Roadmap for the Contracting Parties of the Energy Community,* https://www.energy-community.org/dam/jcr:c28b58eb-22db-4ad5-9ed1-4e93b5b613b7/19thMC_Decarbonisation_Roadmap_301121.pdf

[5] *Regulation (EU) 2018/2066, Regulation (EU) 2018/2067*

installations. Additionally, it serves as a fundamental building block towards establishing a future carbon pricing mechanism, an essential step in accelerating the decarbonisation effort.

In parallel, the introduction of the EU Carbon Border Adjustment Mechanism (CBAM) by the EU aims to raise the climate ambition of EU partners and limit the risk of carbon leakage, highlighting the need for EnC to progress on carbon pricing. In concrete, by the implementation of an emissions trading system for electricity, with a price equivalent to the EU ETS to be finalised by 1 January 2030.Adopting a carbon pricing instrument is also essential for a second reason. The Electricity Integration Package[6], adopted by the EnC Council in 2022, sets out the steps towards the complete integration and coupling of the electricity market between the EnC CPs and the EU. The timely implementation of a carbon pricing scheme would prevent the distortion of competition among CPs and across the whole EnC. It would enable the successful integration of the electricity markets.

Moving towards this direction, the European Commission presented the New Growth Plan[7] for the WB6 aiming to accelerate the economic convergence with the EU, setting as a priority the integration and decarbonisation of the WB6 energy markets. Implementing a regional carbon pricing scheme for all the EnC CPs requires a coherent and comprehensive design of the instrument accompanied by the assessment of the impact of various policy options on the economy of the EnC CPs. As the Ministerial Council of the Energy Community Secretariat concluded in 2023 "Ahead of the 2024 meeting and so as to inform its future decision, the Ministerial Council invited the European Commission to carry out an impact assessment on the various policy options for a regional carbon pricing model at the Energy Community level, taking into account the summary report on technical consultations on carbon pricing held in the second half of 2023". Given the increased prospects for accession, it is crucial to thoroughly review and analyse the implementation of a carbon pricing scheme for the EnC CPs.

1.2. Objectives of the study

Carbon pricing, being one of the cornerstones of the EU climate and energy policy, has been a recurrent theme in the dialogue between the Energy Community and the EU. The establishment of carbon pricing, at a level equivalent to that of the EU ETS, imposes considerable challenges to the energy system, but especially to the electricity sector, which lags in terms of emission reduction and renewable use. By 2021, coal represented 32.5% of power generation in the Energy Community. The figure, though, obscures the heavy reliance on lignite in some CPs, especially in the Western Balkans. In Serbia and Bosnia and Herzegovina, generation by lignite represented around 60% of total electricity production. As for Kosovo*[8], electricity production depends almost exclusively on two lignite stations. Even in Ukraine, where the electricity sector is dominated by nuclear power, coal represents 22-23% of gross generation. On the other side of the spectrum, renewables are the primary source of electricity in Albania and Georgia due to the abundance of water resources.

At present, though most of the CPs do not have any carbon pricing scheme in place, some of them have adopted carbon pricing schemes to pre-empt the impact of the implementation of the EU-CBAM. Even in these cases, the level of carbon pricing or the design of the schemes have been proven insufficient to reduce coal consumption substantially.

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[6] *The package comprises the Electricity Regulation, the ACER Regulation, the Network Code on Emergency and Restoration and four market and system operation Guidelines, namely on Forward Capacity Allocation, Capacity Allocation and Congestion Management, System Operation and Electricity Balancing and a Procedural Act on fostering regional energy market integration in the Energy Community.*

[7] *COM(2023) 691 final*

8 ***This designation is without prejudice to positions on status and is in line with UNSCR 1244/1999 and the ICJ Opinion on the Kosovo declaration of independence.*

The implementation of the EU-CBAM, which aims to tackle the risks of carbon leakage by ensuring the EU importers of electricity and other goods (e.g. cement, steel, etc.) face similar carbon costs to those applied to the domestic producers in the EU, will affect the EnC economies. Exports from the EnC CPs to the EU Member States (MS) of electricity and other carbon intensive goods – subject to CBAM – , may be impacted. Therefore, the EnC CPs may become less competitive when the obligation to buy CBAM certificates (corresponding to the carbon price that would have been paid had the goods been produced under the EU's carbon pricing) enters into force.

This study aims to contribute to the discussion about the implementation of CO_2 pricing in the EnC CPs, providing qualitative and quantitative insights. It presents the main design options for carbon pricing from a regulatory, legal, and technical feasibility perspective, comparing strengths and weaknesses for each option.

The study quantifies impacts of carbon pricing policies to each CP in various dimensions. In combination with other measures, carbon pricing accelerates energy transition, transforming power sector and energy processes in the industry. It reduces CO_2 emissions through the decommissioning of carbon intensive installations, contributing to mitigation of climate change. From an economic perspective, moving away from conventional fuels requires capital intensive investments, and thus high costs and available sources of funding. Nonetheless, decarbonization investments may stimulate the economies, enhancing employment and upgrading workforce skills, and therefore alleviating the costs to the economies. The study tries to isolate the impacts of carbon pricing to the EnC CPs given the complex interdependencies between energy, economy, and environment.

2. Policy Options

All forms of carbon pricing are designed to address the externalities associated with GHG emissions and provide a financial incentive for emission mitigation. The study offers an overview of different carbon pricing mechanisms and the key design options. This includes the establishment of market mechanisms, such as a regional ETS but also simpler approaches, such as carbon taxation or a fixed-price ETS. Carbon pricing scheme designs are coded into policy scenarios that represent the policy options currently available for the EnC Contracting Parties.

The **market-based ETS** is a mechanism where the total emissions cap can be set in line with the EnC CP's emissions mitigation targets. The price of allowances is determined by the balance between supply (the cap) and the demand, which means that this scheme can bring uncertainty to the regulated entities in regard to the carbon price. Allowances can be auctioned, while reduced rate of surrendering can be applied to specific sectors to reduce the cost burden and to limit the risk of carbon leakage. ETS requires a new administrative structure to track and enforce allowance ownership, requiring substantial capacities to implement the emissions trading. Coordination on policy design amongst EnC CPs would be necessary to ensure a well-functioning regional system.

The policy instrument that would provide both carbon price certainty and an introduction to an ETS mechanism would be a **fixed-price ETS**. If there is a clear policy preference to achieve price parity with the EU ETS by 2030, or to provide a smooth start to carbon pricing for businesses, CPs could consider a harmonised launch of a regional fixed-price ETS. Policy design options need to consider setting the price trajectory and determining the method of dealing with carbon leakage, i.e. reduced surrendering rate requirements or free allocation. The absence of a binding cap can make this a cost-controlled transitional phase of the carbon pricing policies into the CPs, implying uncertain abatement. However, the required institutional and legal conditions are very similar to those potentially required for a later market-based ETS, so the associated administrative sunk costs are low. The transparent fixed-price trajectory reduces the risk for companies investing in abatement technologies.

Similarly to a fixed-price ETS, **a carbon tax** can provide a carbon price certainty, while this option can be less administratively demanding, as it will mostly be aligned with the existing frameworks and institutions. A carbon tax will in some cases however require new institutional capacities and new institutional relationships in and between public bodies. A carbon tax could be set in line with the EU ETS price by 2030 and could also be consistent with the EnC CPs' decarbonisation commitments. The harmonisation of carbon taxes between EnC CPs could help to equalize competition and reduce any distortions and would help to coordinate their emissions mitigation ambitions. Harmonised carbon taxation could also prevent carbon leakage among the CPs by reducing or eliminating the price differential between them. However, carbon leakage can remain a problem between the CPs and third countries. In case the carbon tax is applied as a transitionary measure, harmonisation of carbon tax could also be beneficial as a pre-requisite for the implementation of a regional ETS. Possible tax-coordinating measures could take the form of a memorandum of understanding, or a reciprocal agreement, for example in the form of a minimum tax rate.

The **accession to the EU-ETS** requires the transposition of all related EU legislation and provides access to a well established, efficient market ETS. Yet, the management of the system (e.g. allocation, monitoring and enforcement, determination of the amount of free allocation for industrial installations in line with EU rules) requires the establishment of competent national authorities and the development of administrative capacity. Operating under the EU legislation implies that EnC CPs' installations would be subject to the same rules as the installations currently under the EU-ETS. Early integration to the EU-ETS carries a price risk; expected high ETS prices for 2030 can pose challenges to CPs with carbon-intensive energy mix. On the other hand, the EU-ETS provides solidarity mechanisms to alleviate the relatively high-cost burden on installations. Options include the use of the Modernisation Fund, the distribution of 10% of auction revenues for solidarity and cohesion, and the possibility for indirect cost compensation for energy intensive industries to mitigate excessive increases in electricity prices (subject to EU State Aid approval).

The Table 1 provides a comparison between the different carbon pricing options against key assessment criteria:

Table 1: Comparative analysis of different carbon pricing options

Options	Assessment criteria				
	Certainty on reaching mitigation targets	Certainty on carbon price level and possibility to 'phase in' slowly	Admin costs of transitioning to the EU-ETS	Measures against carbon leakage	Legal and technical feasibility
Market ETS	++	-	+	++	+
Fixed price ETS	--	++	+	+	++
Carbon tax	--	++	--	--	+++
Integration to the EU-ETS	++	--	N/A	++	+

In this context, the study has designed three main policy scenarios that represent alternative options of carbon pricing. All scenarios are compared against a baseline case, which does not include additional carbon pricing policies, apart from those already enforced by July 2024. **Baseline scenario** does not commit to climate pledges for 2030 or net zero targets in the longer period. It assumes fragmented electricity markets, limited grid interconnections and a lack of additional policies to support the energy transition in buildings and transport. Nevertheless, even the policy of non-compliance does not take place in void; due to the absence of carbon pricing, CBAM sectors are subject to CBAM payments concerning their exports to the EU. Furthermore, investors are assumed reluctant to finance greenfield investments in coal due to high-risk premia for emission intensive technologies.

Policy scenarios introduce alternative options of carbon pricing starting from 2026. Carbon pricing is evaluated in the broader context of decarbonization. Therefore, all three scenarios share decarbonization policies for non-ETS sectors, buildings, and transport, roughly aligned with the NECPs (WAM scenarios). They assume integrated electricity markets, strong grid interconnections, high net transfer capacities, all of which support electricity trade between CPs themselves and the EU. Furthermore, they all comply with the net zero emissions target for 2050. The scenarios differ in the magnitude, sectoral coverage, and design of carbon pricing, which is restricted to ETS sectors. Non-ETS sectors are excluded from carbon pricing in all decarbonization scenarios.

Policy scenario 1 – Electricity Only assumes a carbon price equal to EU-ETS since CO_2 price for electricity sector and a design compatible with a carbon tax or a fixed price ETS. In this respect two pathways have been modelled:

1) **P1A** - carbon price equivalence with the EU-ETS by 1 January 2030. For this purpose, the study follows EC's recommendation to model an ETS price level at 100€ / tCO_2 in nominal terms in 2030. Therefore, the electricity sector is exempted from CBAM for the export of electricity.
2) **P1B** - More gradual CO_2 price trajectory for the alignment with EU-ETS carbon price as of 2035. This pathway entails CBAM costs before 2035, as the CO2 price is lower than the EU-ETS.

Industrial sectors are not subject to any form of carbon pricing at least until 2030 and therefore bear the full cost of CBAM, similarly to the baseline scenario.

Policy scenario 2 (P2A) extends the sectoral coverage of carbon pricing to the CBAM sectors. The scenario models a unified CO_2 price for all CPs with the aim to reach national climate objectives. As this results in 2030 in a price below EU-ETS price (60% of the EU-ETS), this scenario is not consistent with Art 2(7) of the CBAM Regulation. However, carbon price effectively paid will be deducted from CBAM obligations. Furthermore, CO_2 pricing does not apply to aviation and any other sectors that are not subject to CBAM.

From a design perspective, the scenario is compatible with a regional market and a fixed price regime for all 9 EnC CPs. A policy variant **(P2B)** has been developed, allocating 50% free allowances in all CBAM sectors for the transitional period until 2035. The variant is equally ambitious to the main scenario, as it does not increase the cap on emissions. Variant settings are compatible only with a market-based ETS[9].

Policy scenario 3 projects the integration of the CPs to the EU-ETS by 2030, as part of the broader accession process. It should be noted that in those sectors currently granted free allowances in the EU, the EnC contracting parties will also benefit from free allocation according to the EU-ETS regulation. This study accounts only for the alignment to the EU-ETS 1. The scenario commits to 2030 climate targets and net zero by 2050 for all contracting parties, representing a timely pathway to decarbonization. Air transport and maritime have not been analyzed in the study.

Table 2 Overview of policy scenarios proposed by policy design element

Design element	Policy 1 scenario	Policy 2 scenario	Policy 3 scenario
Type	Fixed price ETS / Carbon tax	Regional market ETS / Fixed price ETS	Accession to EU-ETS (temporary fixed price ETS)
Start date	2026	2026	2026
Sector coverage	Power supply sector	CBAM covered sectors	EU-ETS sectors (excl. aviation and maritime)

[9] 50% free allowance in a fixed price would affect emission reduction, as the cap on emission is not fixed. Free allowances in a market based ETS affects the allocation of emissions, but not the cap itself.

Ambition level	Consistent with net zero by 2050	Consistent for NECP for 2030 at regional level. Consistent with net zero by 2050	Consistent with NECP for 2030. Consistent with net zero by 2050.
Cap setting	No specific cap for the electricity sector, emission reductions determined by the EU-ETS price	Top-down manner based on NECPs. Align overall cap and trajectory with national mitigation objectives after 2030	Derived by the EU-ETS price
Allowance allocation	100% rate of surrendering	Full auctioning	Full auctioning
Use of revenues	• Employer social security contributions (impacts assessed and used for the overall macroeconomic results) • Funding Green investments (impacts assessed) • Lump sum transfers to households, to mitigate the adverse impacts by carbon costs (impacts assessed) • Reducing indirect taxes (impacts assessed)		

3. Energy system results

3.1. Energy demand

The strong growth prospects of the EnC CPs exert an upward pressure in energy demand, despite negative demographic prospects. Nevertheless, buildings efficiency, transport electrification and process efficiency in the industry have the potential to decouple energy demand from increases in economic activity.

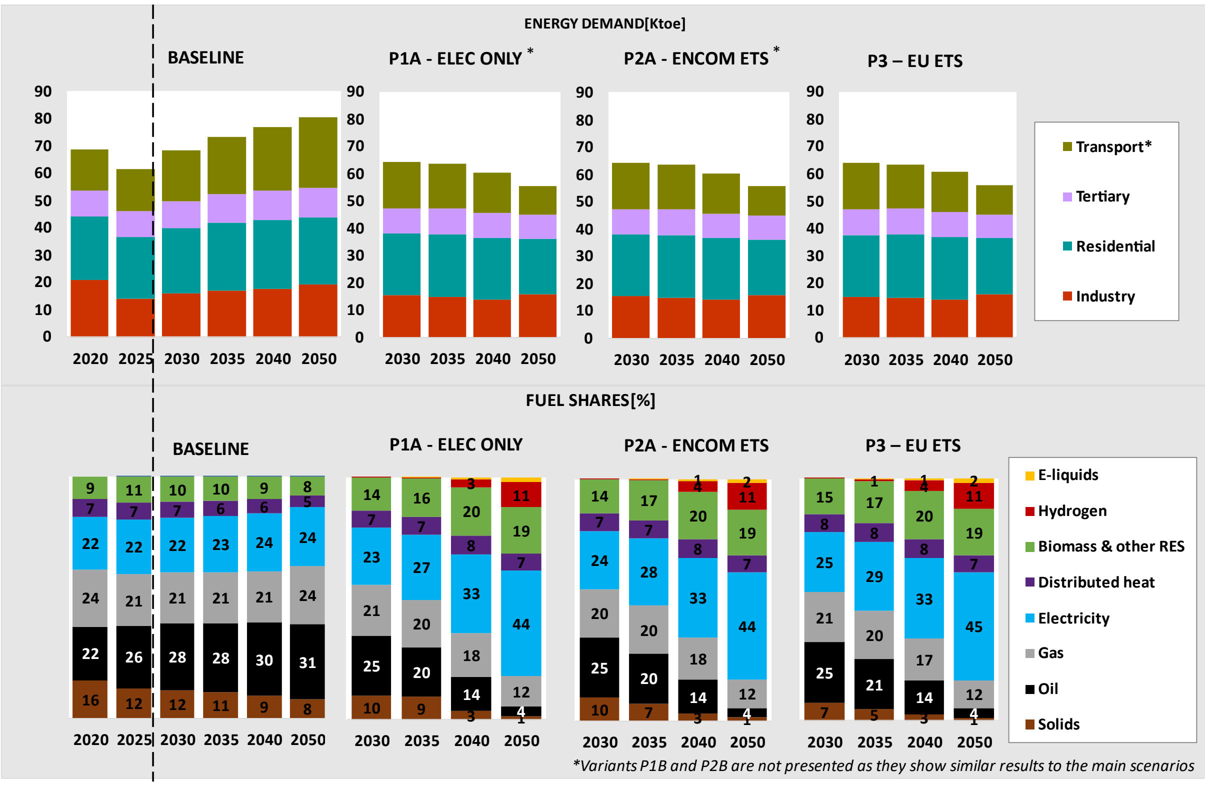
Baseline scenario continues the historical trends of the energy system, showing moderate efficiency and increasing demand. In 2030, the aggregate demand is lower by 3% compared to 2020, as the Ukrainian economy is assumed to have recovered only partially from Russian invasion. By examining the other CPs though, the increasing trend is clear, approximately 11.5% due to increase in economic activity. By 2040, overall energy demand increases by 8.5% on average and 21.5% excluding Ukraine./

Due to the lack of ambitious policies, the baseline scenario does not decarbonize the fuel mix. Oil products are predominant on transport sector and the electrification is limited in space heating in buildings; clean fuel blending in gas pipelines is not implemented at all, as the production of renewable gases remains uncompetitive. The scenario shows a reduction of coal as a relative share; the consumption of coal fades out in the buildings sector due to income increases and adverse health effects, whereas it is stabilized in heavy industry. Leaning aside the impact of war, the dynamics of the energy system show higher shares for transport, as activity gradually converges to the EU levels. On the other hand, the contribution of buildings is lower due to moderate buildings efficiency.

Policy scenarios share assumptions about additional policies in buildings and transport. They present alternative pathways on energy transition which differ by the speed of decarbonization in the ETS sectors. Therefore, the scenarios present common trends in other sectors, which constitute 70-80% of energy demand.

Energy demand in the decarbonization scenarios differs significantly from the baseline at the regional level. NECP policies and measures drive the reduction of energy consumption by 6-7% in 2030, compared to baseline. Wide transport electrification and buildings renovation cause great efficiency gains in the next decades, reversing the increasing trends in energy demand. Therefore, energy demand decreases by 21-22% compared to the baseline scenario by 2040.

Figure 1: Energy demand by sector and fuel in the energy community

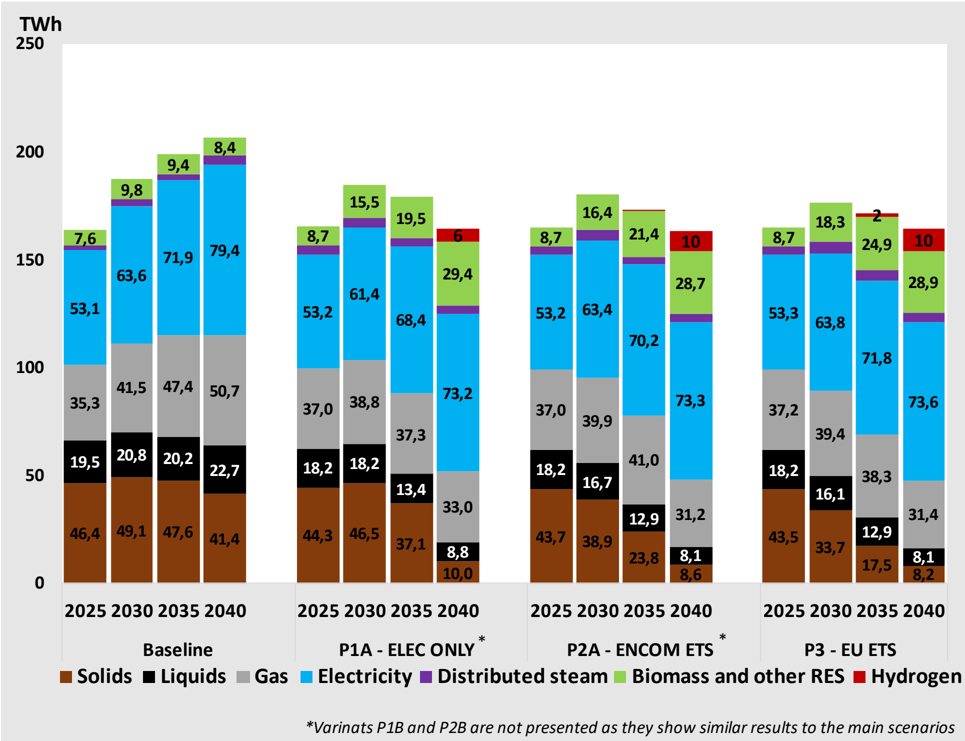


Furthermore, electric vehicles, heat pumps for space heating and the use of clean fuels in industrial sectors transform the energy mix in the long run and increase the demand for electricity. By 2040, electricity represents 33% of the energy mix, increasing by 10pp compared to the Baseline. Nevertheless, the impact on fuel mix and electricity demand remains limited in the current decade; the wide use of novel technologies is projected after 2035.

Decarbonization scenarios differ on the speed of decarbonization in the industrial sectors. This can be tracked by the share of coal in final consumption. **Scenario P1A**, which includes a CO_2 price only for electricity hinders fuel substitution and energy efficiency improvements within the sector Excluding industry from carbon pricing delays fuel substitution and energy efficiency in the industry. Substitution of coal by cleaner alternatives is slow in 2030, and moderate by 2035, due to the expectation of high CO2 prices in the long run. Additionally, the absence of carbon taxation delays the blending of natural gas with greener alternatives, resulting in pipeline gas maintaining its current carbon content until 2035.

Implementing moderate CO2 pricing to CBAM sectors (**scenario P2**) leads to a 15% reduction in coal consumption compared to Scenario P1A. This decrease is significant, and when combined with a shift away from oil, results in the results in the abatement of 13.5Mt of industrial emissions, or 16% decrease compared to the baseline scenario in 2030.

Figure 2:Energy demand in the industrial sectors of the Energy Community



Scenario P3 presents the greater emission abatement for 2030, mainly due to higher ETS prices and to a lesser extent the broader coverage of ETS pricing. Notably steel and cement sectors account for 70% of energy related emissions in the energy community. High CO2 prices have the potential to abate coal consumption by 27% compared to the baseline by 2030 and 42% by 2035. Furthermore, the scenario projects the blending of natural gas with clean gases by 2035, a policy that contributes to further emission reduction.

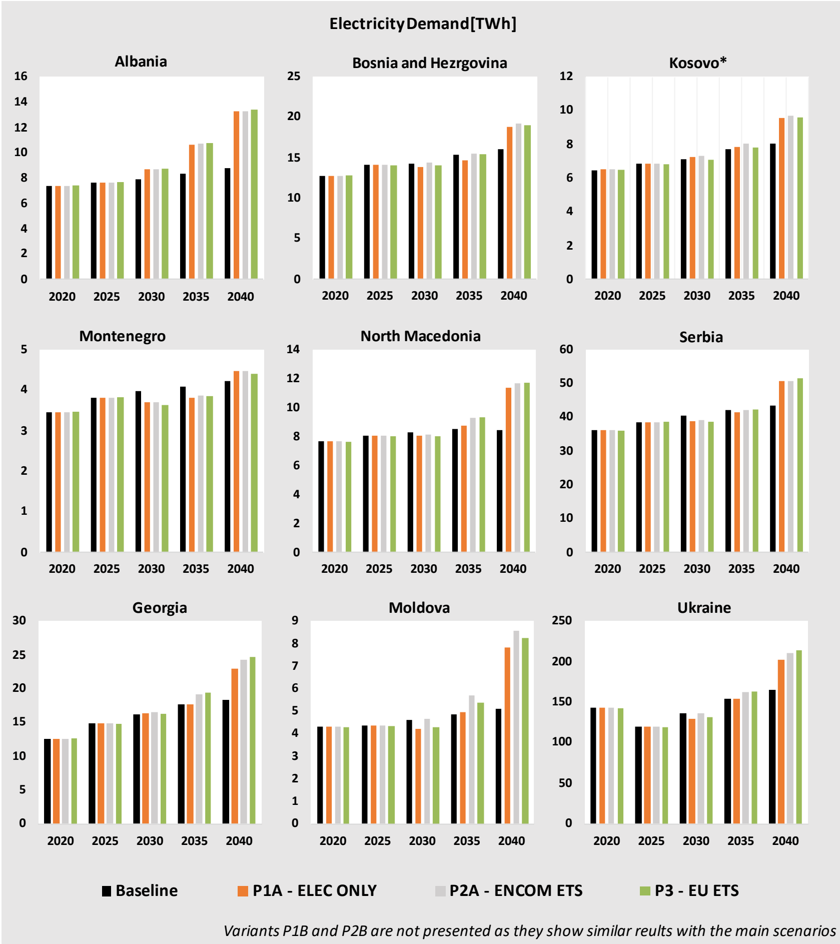
3.2. Electricity demand

In baseline scenario the demand of electricity is mainly affected by the economic growth of each CP; week climate policies prevent the electrification of end use sectors, thus resulting in moderate increases in the demand of electricity in all CPs.

Decarbonization scenarios suggest the electrification of end uses, including electric vehicles, buildings sector and low enthalpy heat in the industry. Electricity demand is also affected by the consumption of clean fuels, produced by renewable electricity. The latter are used mainly in processes that are hard to electrify, such as long-haul transport and high enthalpy heat in the industry. In the CPs that currently depend on gas for space heating, small quantities are used in buildings sector, to address agent heterogeneity for space heating.

Small variations from the baseline scenario are expected by the end of the decade, as transport electrification is at an early stage. In some cases, energy efficiency measures may result in lower demand of electricity compared to the baseline scenario in 2030. In the long run all CPs show high increases on electricity demand, despite investments in energy efficiency; this is expected, as electrification is a driver for energy efficiency. By 2040, the average increase in the demand of electricity is 51% and depends on assumptions about economic growth and the speed of transport electrification.

Figure 3: Electricity Deamand on EnC CPs



The demand for electricity varies slightly among decarbonization scenarios, as all three share assumptions about decarbonization in buildings and transport. In most cases though, electricity demand is lower on **scenario P3** compared to the other two decarbonization scenarios. This is explained by the combination of higher efficiency in the industry and higher prices of electricity.

3.3. Electricity generation

The **baseline scenario** is based on existing measures, aligned with the main directions of the WEM scenarios presented in the NECPs. It does not project any form of CO2 pricing, apart from the CPs already enforced a relevant policy. This affects the electricity trade with the EU, as electricity imports from the Energy Community are subject to CBAM costs. The phase-out of existing coal stations is not mandatory, and any refurbishment depends on cost criteria and technical lifetime constraints. This scenario assumes fragmented electricity markets and slow grid expansion, which inhibit the broader expansion of renewables.

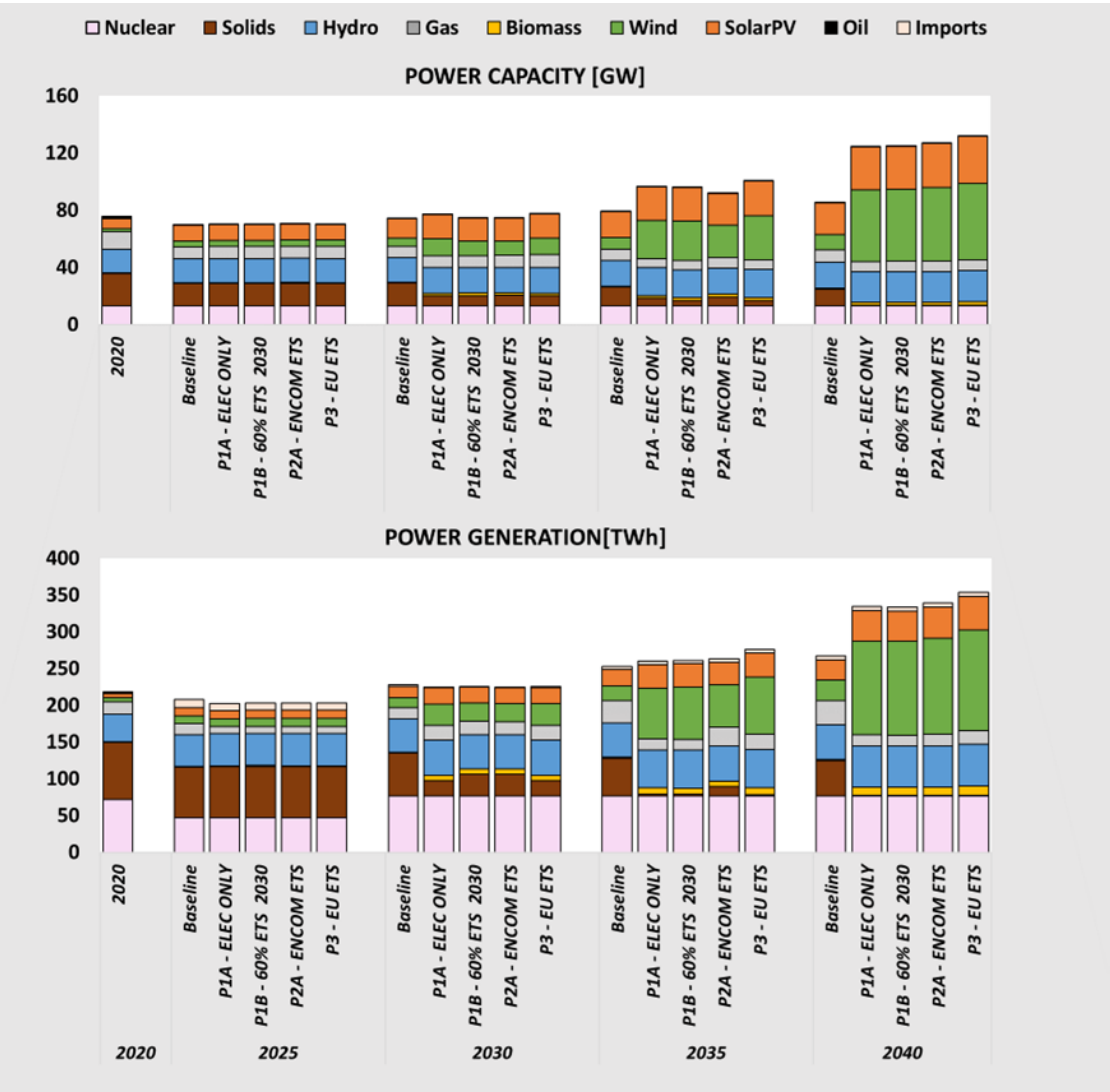
On the absence of carbon pricing the baseline scenario extends the operation of solids-fired plants wherever this is technically feasible and economically rational. Nevertheless, the scenario does not project new coal investments, as the investors' risk of stranded assets is high. The share of coal gradually decreases due to the decommissioning of older units and increasing demand for electricity. In all CPs, the void is mainly covered by RES which are the most competitive option for greenfield investments, even without any support scheme. To a lesser extent, it is covered by natural gas, but only for the CPs that already use gas in power generation.

At a regional level, the imposition of carbon pricing has the potential to transform the power mix of energy community. At a CP level though, the impact is heterogenous and depends on the carbon intensity of the power mix. Albania and Georgia are mildly affected due to reliance on hydropower.

The gradual increase of CO_2 price questions the lifetime extension of existing solid-fired plants. An ETS/CO_2 tax price equal to 60 euros/ton would add 56 euros to the variable cost of a coal station, rendering its operation non-competitive. This is the case of **scenario P2**, where the CO_2 price is set at 60 euros per ton for 2030 rising to 100 euros for 2035. Generation from coal is almost halved by 2030, reducing emissions by 34Mt; it is mainly substituted by variable RES which reach 26GW at that year. Although fading at the EnC level, generation form coal is still substantial in some CPs in 2035, such as Kosovo (30%) and Serbia (20%). At that year, variable RES capacities reach 45GW.

Scenarios P1A&P3, assuming price convergence with the EU, moves in the same direction as scenario P2 yet raises the decarbonization ambition for 2030. The scenarios project further reduction of coal-based generation, reducing emissions by 47Mt, compared to the Baseline scenario. This is driven mainly by additional wind and solar capacities, which reach 28.5GW, but also by higher use of natural gas and the deployment of other RES technologies (hydro, biomass). Yet, investment constraints impede the direct substitution of coal plants by RES, even if additional carbon costs justify this. After a certain level, any increase in the CO_2 price in the short run shows diminishing returns in emissions abatement.

Figure 4: Power generation and capacity expansion in Energy Community



High carbon prices, equal to EU-ETS, are more effective towards 2035, as investment constraints are loosened. This enables the penetration of RES and almost complete replacement of coal by 2035. Therefore, variable RES capacities reach 55GW in scenario P3, adding 10GW from scenario P2 which assumes lower than EU-ETS prices at that year. Scenario P1A projects slightly lower capacities than due to lower demand of electricity and clean fuels on ETS sectors.

The variant P1B assumes lower prices than EU-ETS in the short run but converges to EU-ETS prices faster than P2. Therefore, results are similar to P2 in 2030, but converges to the results of P1A by 2035. Therefore, the variant projects the highest investment ratio across the scenarios for the period 2030 – 2035.

3.4. Cost of power generation

Electricity generation costs are projected to increase in policy scenarios driven by the introduction of carbon pricing. The impact on electricity costs is connected to the carbon intensity of the power mix, as the increase in costs results mainly from the carbon cost component. To a much lesser extent, generation costs tend to increase due to RES investments used to avoid carbon pricing from thermal power.

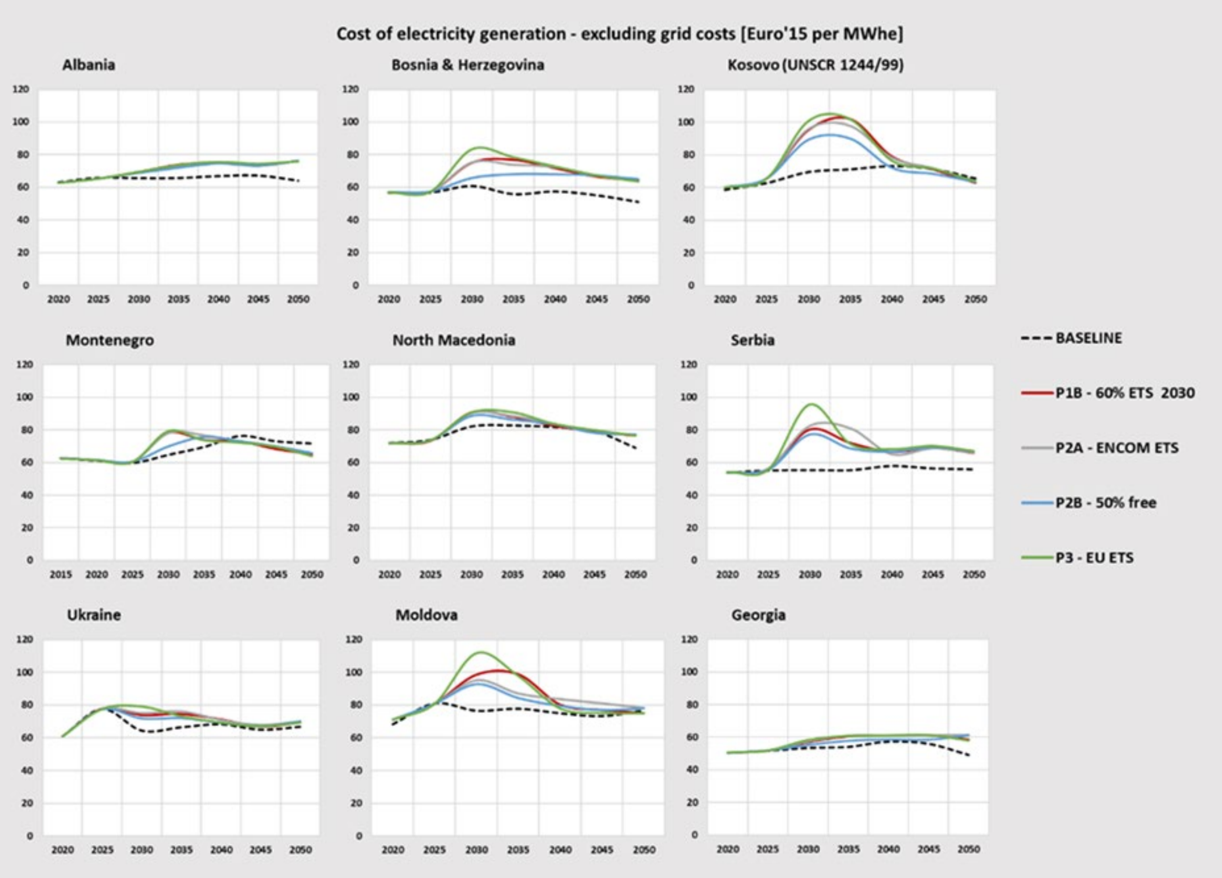
The impact varies according to the share of carbon-intensive sources in the power mix, as well as the current cost of electricity supply. On the CPs where generation from coal still represents a considerable share of gross power, impact on costs is likely to be high. In the cases of Bosnia and Herzegovina, Kosovo and Serbia investment constraints prevent the complete substitution of lignite in this decade. Therefore, direct emissions costs are mainly responsible for increases to cost of power supply.

The impact is smoother on the CPs that currently rely on hydropower. In the cases of Albania and Georgia, the costs of electricity supply rise mainly due to RES investments required to support increasing demand of electricity. Nuclear power plays a similar role to hydro for Ukraine, alleviating CO_2 emission costs. Additional costs are also limited for Montenegro, as competitive RES result in the early substitution of lignite power.

In North Macedonia emission costs are minimized in all scenarios, as lignite plants get decommissioned prior to 2030 and replaced by RES. Therefore, increases in the cost of electricity generation are mainly attributed to new investments and to a lesser extent on the emissions cost of natural gas. In case of Moldova, price increases come mainly from emission costs of gas generation, which hold a large share of power generation even in the most ambitious scenarios until 2035.

On average, 2030 electricity costs are projected to increase by 13-29% compared to the baseline. Highest costs are projected to scenarios P1A and P3, as they converge to EU-ETS prices already by 2030. At that year, variant P1B and scenario P2A show mildly lower costs (21% increase), as they assume lower CO_2 prices than EU-ETS. Variant P2B shows the lowest costs, leveraging on the distribution of free allowance to electricity installations. By 2035, power systems have the time to adapt and abate carbon intensive generation. As the carbon cost component gradually phases out, the cost of power supply largely reflects the cost of renewable generation and its balancing requirements. Therefore, pressure in electricity prices is alleviated, even with EU-ETS prices.

Figure 4: Cost of electricity generation

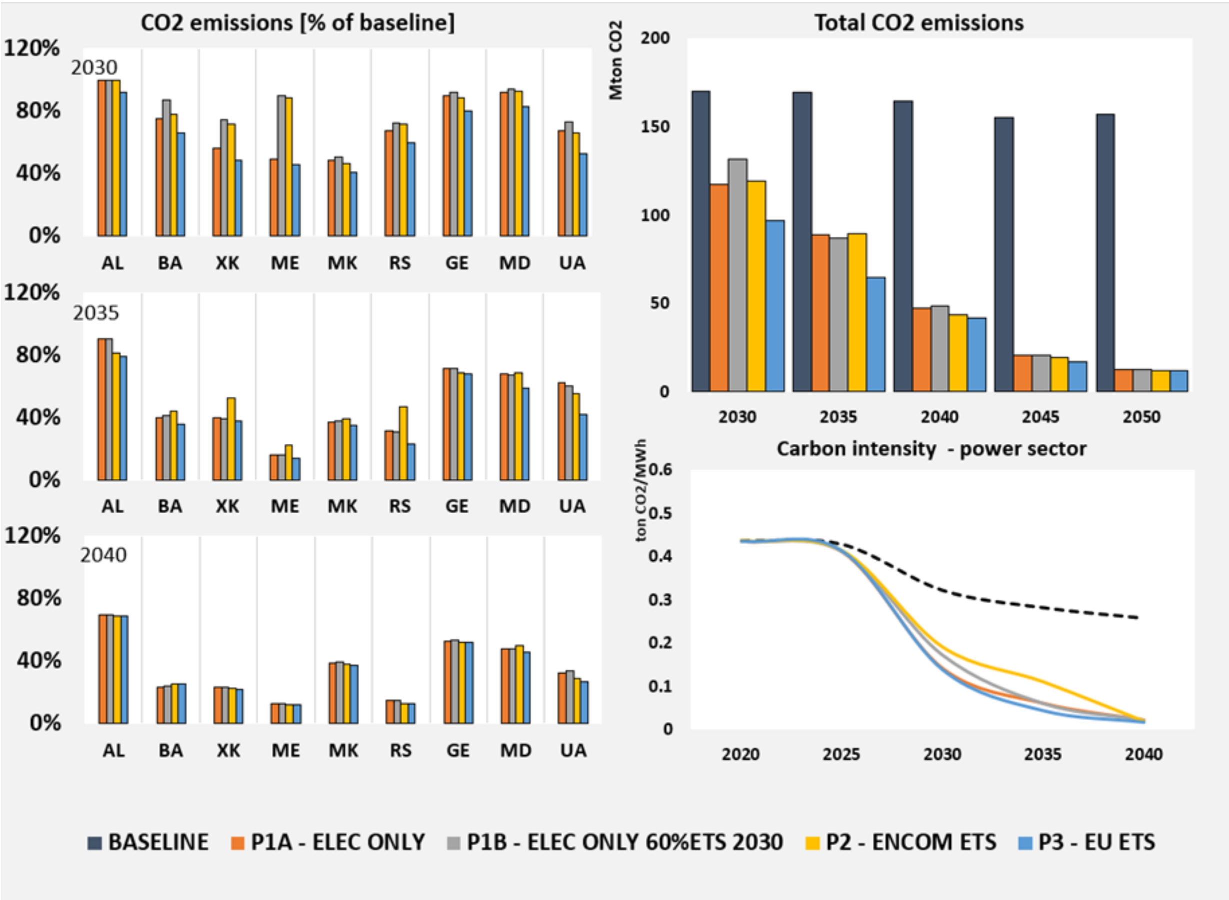


3.5. ETS emissions

Emission results show that any form of modelled carbon pricing in the EnC CPs is likely to result in significant emissions abatement in the covered sectors, compared to the baseline. Substantial decrease in emissions is found in all policy scenarios compared to the baseline, even the least ambitious one (variant P1B). Nonetheless, the magnitude of the decrease and compliance with emission reduction targets depend on the level and sectoral coverage of carbon pricing.

Power sector contributes the most to emission reduction, both in the short and medium run. In scenarios P2 and P3, where carbon pricing is extended to industrial sectors, power sector accounts for 70 and 78% of emissions reduction. This reflects the current carbon intensity of the power mix, but also the maturity of RES in electricity, which substitute emission intensive resources. Nonetheless, industrial sectors offer a valuable contribution to the achievement of GHG targets. Although abatement options are less mature and costly, carbon pricing pushes industrial installations in improving energy and operational efficiency, decreasing moderately energy and process related emissions.

Figure 5: CO2 emissions in ETS sectors



Applying EU-ETS price on the power sector abates 50 Mtons of CO2 emissions for the year 2030, or 30% of total ETS emissions compared to Baseline scenario, as illustrated in scenario P1A. Meanwhile, the extension of CO2 pricing to all ETS sectors, envisaged in scenario P3, achieves an additional 13% decrease; this corresponds to 22 Mtons of CO_2 compared to policy scenario 1.

The application of gradual CO2 pricing to CBAM sectors (P2) achieves similar emissions abatement to scenario P1A, albeit at different sectoral contribution. Decarbonization is concentrated on the power sector on scenario P1A, whereas scenario P2 spreads mitigation effort to all CBAM sectors. Equal emission reduction among the two scenarios is explained by the high mitigation potential of power sector in the short and medium run, compared to the industry. The lowest emissions reduction is achieved by the variant P1B, achieving 22.4% emission reduction compared to the baseline scenario. This is reasonable, as the coverage of carbon pricing is limited to power sector and price levels much lower than EU-ETS.

Table 3: Emission reduction by scenario

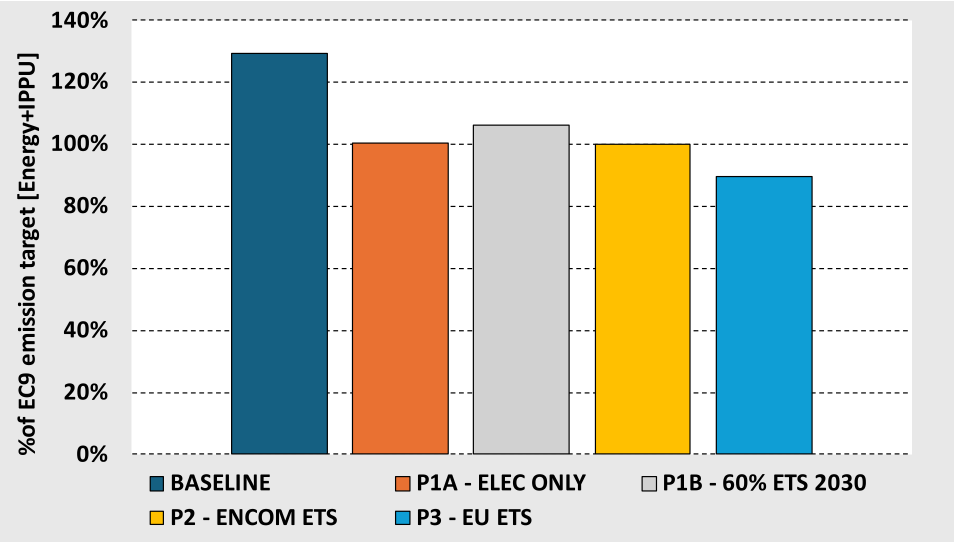
Policy Scenario	2030	2035	2040
P1A Scenario	30.3%	47.6%	71.3%
P1B Variant	22.4%	47.6%	70.7%
P2 Scenario	30.0%	47.4%	73.5%
P3 Scenario	43%	61.8%	74.8%

Results reveal similar trends for 2035. Policy scenario 3 achieves the highest reduction on emissions – 61.8% compared to the baseline scenario. Mitigation is lower in other policy scenarios as they still lag in sectoral coverage and/or price levels. Following policy convergence by 2040, deviations between scenarios are minimized.

3.6. Climate targets

The study examined compliance with climate targets, based on the WAM scenarios of the NECPs. GHG targets include all sectors of the economy, both energy, process related and LULUCF emissions. The study isolated the **emission reduction targets** in the energy sector and IPPU[10] (Industrial Process Emissions) from the WAM scenarios of the NECP. Hence, a sub-target was constructed for energy and process related CO2 emissions, against which all policy scenarios were tested. Another important target in the NECPs is related to the **RES shares** (% of final energy consumption). The study results on energy consumption and power supply made possible the calculation of the RES shares indicator, as defined in the EnC acquis. Emission reduction and RES shares targets are mainly affected by ETS sectors in the short run, yet the contribution of non ETS sectors, buildings and transport is also substantial.

Figure 6: Complianace with emissions targets



Baseline scenario fails to achieve the emission reduction and the RES penetration needed to reach the 2030 targets, as it does not include additional measures in both demand and supply sectors. On the other hand, carbon pricing combined with decarbonization policies in buildings and transport have the potential to comply with emissions targets.

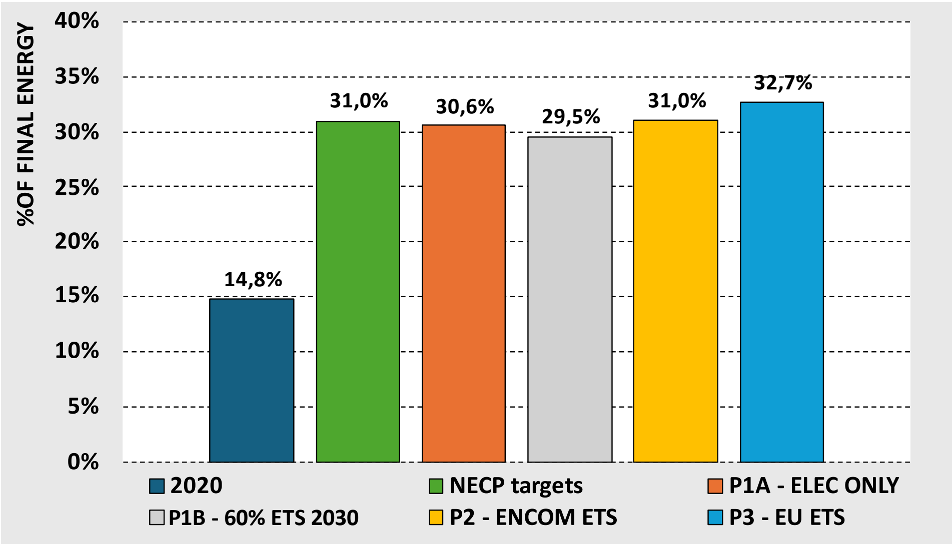
Scenario P1A meets targets for emission reduction, relying on the abatement from the power sector, which faces a CO_2 price equal to the EU-ETS by 2030. The target is reached at a regional level, though most CPs reach their national declared goals. Nevertheless, P1A slightly barely misses the target for RES-shares, due to insufficient penetration of RES in the industry. It should be noted though that this result comes mainly from the heating and cooling sector of Ukraine, which greatly impact the aggregate results. Although variant P1B achieves considerable emission reduction in the power sector, this is not enough to compensate weak policies in other ETS sectors. It fails to achieve both targets, as it combines narrow scope of carbon pricing with a more gradual price increase. Unlike the main scenario P1A, non-compliance is shared by most CPs.

Scenario P2 (P2A and P2B) meets both targets at a regional level; It achieves similar emission reduction with P1A, albeit at a different sectoral and national contribution. Due to uniform carbon pricing on the CBAM sectors – which are the most intensive – it spreads decarbonization efforts more

[10] *Process emissions from agriculture, waste sector and LULUCF are out of the scope of the study and therefore are not analysed. Although most IPPU emissions come from ETS sectors, IPPU industries not all IPPU industries are within ETS scope*

evenly than scenario P1A. As far as it concerns RES shares, it shows worse performance than P1A in most CPs but a better one for Ukraine, which influences greatly the RES indicator at a regional level. Therefore, the target is reached at a regional level, although several CPs stay below national commitments.

Figure 7: Complianace with emissions targets



By combining the broadest scope for carbon pricing and the highest CO2 price among scenarios, scenario P3 complies with both targets at a national level. Nevertheless, it overshoots both targets at the regional level, especially emission targets. This reflect disproportional efforts from the region, especially in the CPs where the divergence is substantial compared to the national pledges.

4. Macroeconomic results

The impacts of alternative ETS schemes were assessed by the GEME3-EnC model, a computable single country general equilibrium model. Between the economic and the energy model a soft link was established and projections on the power generation mix, investments by power generation technology, carbon prices and energy developments in the ETS industries were received as inputs. The economic analysis also extends to the influence of alternative carbon recycling options on macroeconomic performance. In total 17 were assessed, 5 main scenarios and 12 variants.

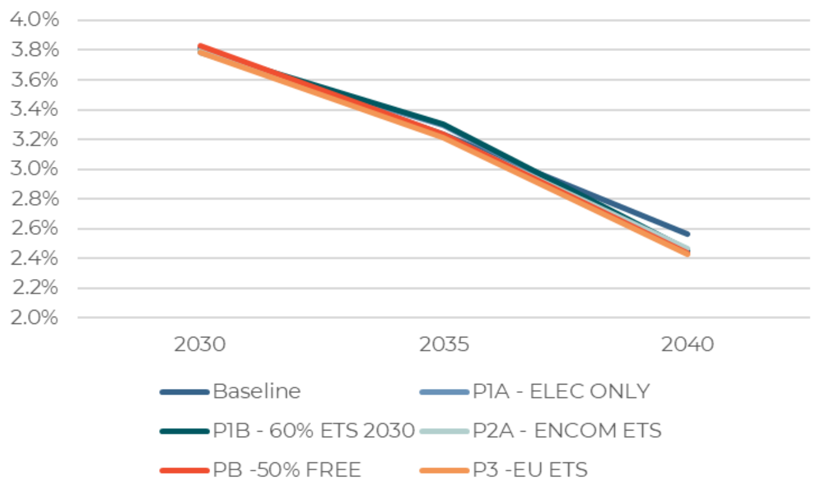
The main drivers of macroeconomic impacts are the additional investments which provides a demand stimulus in the economy, electricity and energy prices which affect energy expenditures hence may stress household's budget and firms' production costs, and the assumptions on revenues recycling. The model's default version assumes mixed financing for investments, which implies that part of the additional green investments will be financed from abroad.

Power generation investments, in all alternative carbon schemes, are largely directed to the deployment of wind and PV capacities (approximately 74%), while hydro and biomass-fired facilities account for 13%. The output effect of additional investments is largely determined by the relative multiplier of the sectors that are engaged in the realization of the investment projects. In total the 4 alternative pathways project an increase in total power generation investments of 31 to 36 billion € over the projection period, which is equivalent to 0.7%-0.8% of the regional GDP. Carbon revenues may reach up to 1.12% of the regional (EC9) GDP and are higher in 2030 as in the longer-term, industries adjust to the new conditions, adopt more efficient production processes, and reduce their emissions.

The impact assessment found small cumulative GDP impacts for the period 2025-2040, which range from -0.22% to -0.64% compared to the Reference case. The effects are found to be higher in the P3-EU ETS scenario and lower in the P1B – 50% ETS 2030. The decarbonization is not found to exert significant impacts on the regional growth prospects as regional average annual GDP growth is found to be smaller only by 0.09% in the P3- EU ETS scenario (i.e. 3.14% compared to 3.2% in the reference).

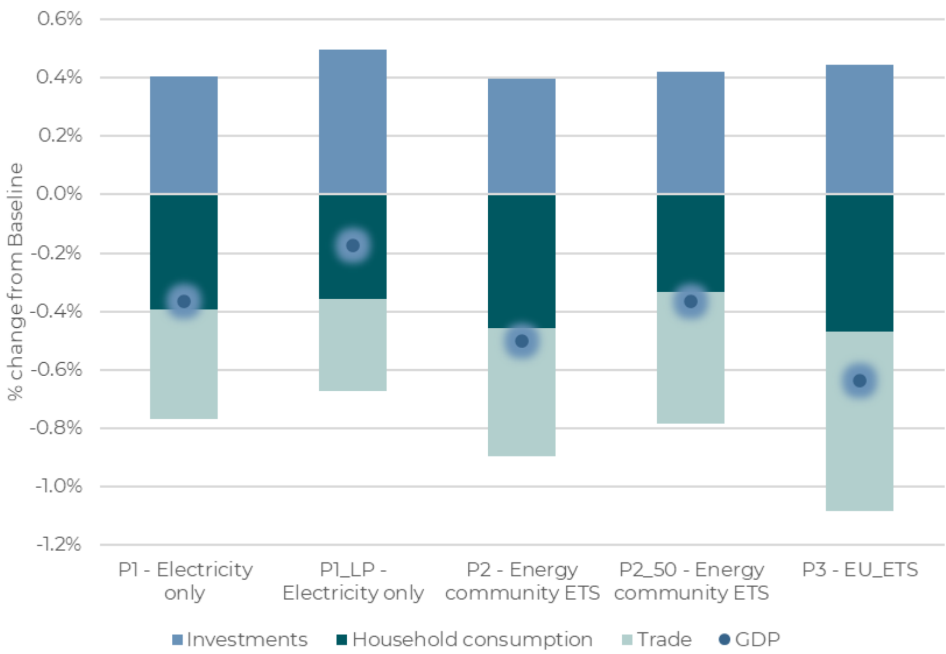
Investments generate a positive impact on the economy via the demand stimulus and the consequent multiplier impacts, highlighting the significant modernization push brought by carbon pricing that sustain macroeconomic performance during the transition. In terms of trade, the deterioration of the current account balance is attributed to the impact of higher electricity and energy prices on competitiveness and on the other hand higher imports of RES equipment. These two effects outweigh the decoupling from imported fossil fuels.

Figure 8: Annual GDP growth rate



Source: GEM-E3EnC

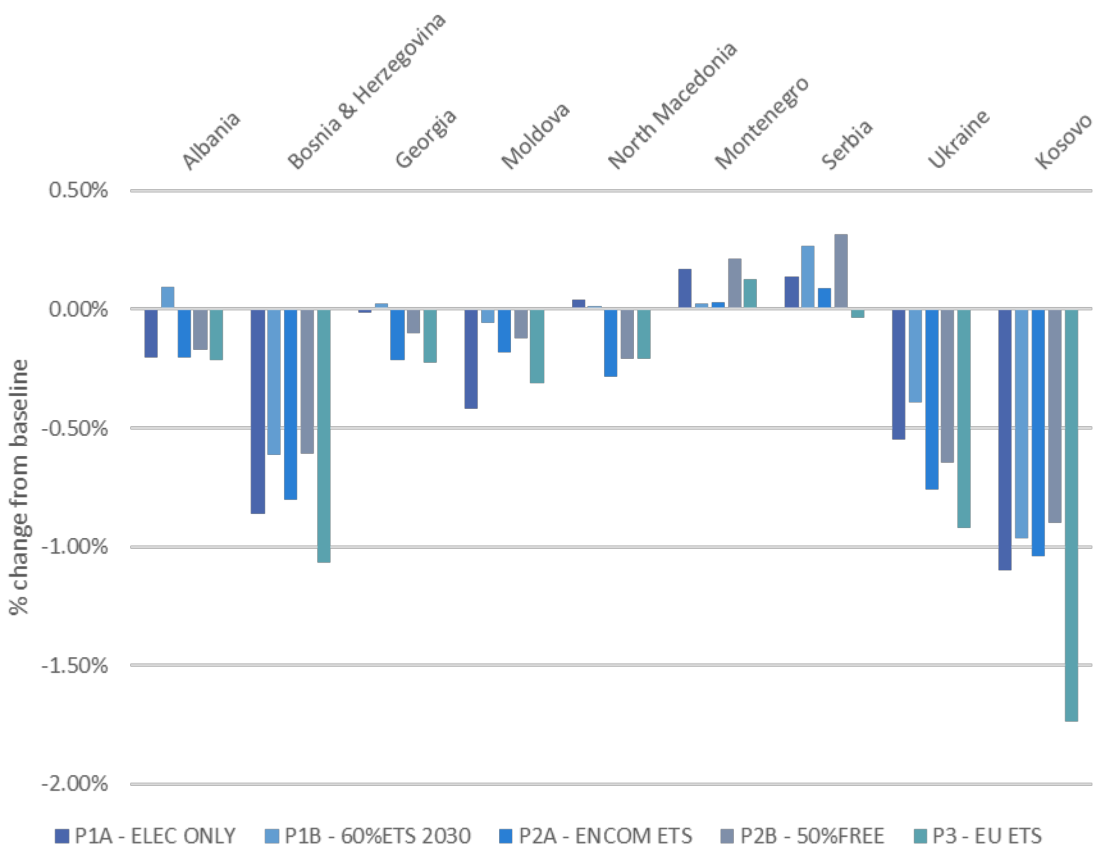
Figure 9: Decomposition of cumulative (2025-2040) GDP impacts



Source: GEM-E3EnC

At the Contracting Parties level, the impacts are driven by the relative contribution of energy intensive industries in the country's production mix, by the level of investments and the extent to which domestic activities can rip off the benefits from extra demand and the recycling of carbon revenues. GDP impacts are found to be higher in Ukraine, Kosovo, and Bosnia Herzegovina, for different reasons. Ukraine has a relatively contribution of energy intensive industries in its total output, Kosovo records lower investments compared to the reference in power generation, while in Bosnia & Herzegovina, higher electricity prices drive the overall outcomes. Smaller impacts are projected for Albania, Georgia, Moldova, North Macedonia, Montenegro, and Serbia. Positive impacts are recorded for the latter (Serbia for example records significant gains from higher investments and from the recycling of carbon revenues). In most of the countries there is a shift from energy intensive activities to the production of clean energy fuels and other activities, such as the production of consumer goods.

Figure 10: Cumulative (2025-2040) GDP impacts by Contracting Party



Source: GEM-E3EnC

In terms of employment, all policy scenarios record gains throughout the projection period for most Contracting Parties, with the effects slowly plateauing when reaching the end of the projection period. P1B and P2B variants score best both per Contracting Party and in total. Overall employment losses in 2030-2040, where exist, are minimal compared to the Baseline, fluctuating between –0.5% to –1.5% across scenarios. The most affected activities are associated with power generation from coal, such as coal mining and the supply of fossil fuels. Employment losses are recorded for the CPs with highly coal-dependent power sectors. On the other hand, positive effects are found in sectors producing clean fuels (such as hydrogen, biomass etc.), construction due to higher investments and some non-ETS industries (e.g. consumer goods industries, electronics, and electrical equipment).

Alternative recycling of carbon revenues and especially when directed to employment support, through e.g. the reduction of social security contributions can minimize the impacts of the transition. The effectiveness of lump sum transfers is found to be the lowest among the alternatives examined.

Table 4: Impact of alternative recycling options on GDP[%]

		No recycling	Indirect Taxes	Labor market	Financing	Lump sum transfers
2030	P1A - ELEC ONLY	-0.9%	-0.5%	-0.1%	-0.8%	-0.8%
	P2A - ENCOM ETS	-0.9%	-0.4%	-0.1%	-0.8%	-0.7%
	P3 - EU ETS	-1.2%	-0.5%	0.0%	-1.0%	-1.0%
Cumulative	P1A - ELEC ONLY	-0.8%	-0.4%	-0.1%	-0.5%	-0.5%
	P2A - ENCOM ETS	-0.9%	-0.5%	-0.2%	-0.7%	-0.7%
	P3 - EU ETS	-1.2%	-0.6%	-0.3%	-0.9%	-1.0%

Source: GEM-E3EnC

5. Conclusions

The policy of CO_2 pricing is an effective mechanism to transform the energy mix of carbon-intensive sectors, namely the power sector and the industry. It should be considered as one key policy in the overall toolbox to support decarbonization, alongside other instruments and policies in non-ETS sectors.

The final comparison of the policy scenarios based on the four assessment criteria can be seen in Table 5 below.

Table 5 Comparison of different policy scenario options

	Assessment criteria			
	Effectiveness	Cost-Efficiency	Proportionality	EU accession preparedness
P1A Scenario	++	++	+	++
P1B Variant	+	+++	++	+
P2A Scenario	+++	++	++	++
P2B Variant	+++	++	+++	+
P3 Scenario	+++	+	+	+++

+++ indicates high, ++ indicates medium and + indicates low alignment with the assessment criteria

All scenarios analyzed in the study present strengths and weaknesses.

Scenario P1A has a moderate performance in most indicators. It reaches emission reduction targets due to great abatement from the power sector, where carbon pricing ramps up quickly to high levels. In the shorter term, the full effectiveness of these high levels is somewhat limited by investment constraints. On the other hand, P1A slightly under-reaches targets for RES in the region, but this mainly due to insufficient performance in Ukraine, which impacts widely the aggregate figures. From an economy wide perspective, industrial sectors are not directly exposed to carbon pricing but face indirect costs due to higher electricity prices. Households are equally exposed to significant increase in electricity prices by 2030. This affects the scoring, notably on proportionality and to a lower extent on cost-efficiency . EU accession preparedness is facilitated by the quick convergence of carbon prices to EU-ETS but undermined by the narrow scope, limited to the electricity sector.

Variant P1B shares all design features of the main scenario P1A but assumes a more gradual convergence to EU-ETS prices. This, coupled with the limited scope of carbon pricing, entails a low effectiveness: P1B fails to meet the 2030 climate targets since, unlike P1A, the emissions abatement in the electricity sector does not compensate for the delayed efforts from industrial sectors. On the other hand, this variant scores better than P1A when it comes to cost-efficiency and proportionality, due to the higher marginal returns of lower carbon pricing levels and since it manages to contain the impact on electricity prices. Lastly, P1B entails low EU accession preparedness, since it entails only partial alignment with EU-ETS scope, design features and price levels.

Scenario P2A shows a balanced performance, as it scores moderately in all assessment indicators. By scenario design, it meets both targets for emission reduction and renewables penetration at a regional level, without overshooting them. In terms of economic effectiveness, the scenario is slightly worse than P1A, due to the higher burden on industrial sectors in the short term. On the other hand, it implies a reduced and more gradual upward pressure on electricity prices, making the scenario less prone to energy price shocks. This is associated with a longer period of sustained prices, due to a slower decarbonization of the electricity generation. Broad scope of ETS coverage supports EU accession preparedness, which is however hindered by the lower prices than EU-ETS. While a market-based ETS would familiarise CPs and their economic actors to the full sophistication of the EU-ETS design, a future transition into the EU-ETS would be more complex to prepare and could impact the liquidity and functioning of the EnC ETS, especially if CPs join the EU (and thus EU-ETS) in a staggered manner.

Variant P2B performs equally well to the main scenario to the indicator of efficiency, as both scenarios share the same cap on emissions for ETS sectors. Impact on GDP is barely lower than the main scenario P2A; carbon payments may be lower in this scenario, but limited revenue recycling almost neutralize the impact. Variant P2B is the most affordable policy option for electricity consumers, as it passes only 50% of CO_2 costs to the prices of electricity. Free allocation though is a sub-optimal method to allocate a resource made scarce by the ETS cap, and therefore such method does not guarantee economic efficiency. Such inefficiencies are not captured in the study, due to modelling limitations. With regard to preparedness to EU accession, the considerations made for P2A apply. However, scoring is further reduced due to the free allowance allocations, which for electricity generation deviates from the EU-ETS approach and entails in this sector the highest effective price differential with the EU-ETS across all scenarios.

Scenario P3 clearly meets all climate-related sectoral targets; it has the potential to abate 43% of the emissions in the ETS sectors of the Energy Community by 2030, compared to the baseline scenario. However, due to high costs and energy prices incurred in the short- and medium term, it scores lowest in terms of economic efficiency and proportionality. High CO_2 prices applied in the short run to a broad sectoral scope amplify the diminishing returns of carbon pricing in the medium term, as investment constraints, related to financial, administrative and regulatory limitations, temporarily hinder the substitution of carbon-intensive technologies. P3 foresees the integration of EnC CPs into the EU-ETS by 2030. This would take place in the broader political and policy context of the overall accession to the EU. As such, the impacts of aligning to the overall EU acquis and to enter the EU single market as full-fledged Member State go far beyond the costs and benefits of aligning and integrating to the EU-ETS. Therefore, the impacts presented in scenario P3 are limited by the scope of this study and should be taken into account accordingly.

Overall, the impact of CO_2 pricing could be significant both in the medium and in the long term and differs across the sectors involved. More specifically, the impact of CO_2 pricing is considered uneven among power sector and heavy industry, at least in the short run, as policy action in power sector yields comparatively higher emission reductions, which can be realized at a lower abatement costs compared to heavy industry due to the maturity of renewable power generation technologies.

Nevertheless, the study shows that expansion of carbon pricing to the industrial sectors yields considerable emissions abatement and hence is required to meet NECP targets, notably if a more gradual ramp up of carbon pricing is needed to smooth the impact on electricity prices. Structural mitigation endeavors in industrial processes are more challenging and costlier, as large-scale commercial deployment is needed in most cases. On the other hand, there is potential for short-term emissions reductions in industry due to improvements in energy and operational efficiency, which have moderate abatement costs and hence would be realized more swiftly, also in case of more gradual increases in CO_2 prices.

The imposition of carbon pricing causes an increase in the supply price of electricity in most CPs. Carbon pricing revenues can be used to mitigate this impact on households, as is done by the EU with its Social Climate Fund. The impact on electricity prices is higher by the end of this decade, mainly due to substituting emission-intensive technologies. Convergence with EU-ETS prices for electricity (scenarios P1A and P3) bring higher prices in the midterm, however they decarbonize the power sector faster. This entails that lower long-term prices are realized faster compared to scenarios with a more gradual ramping up of CO_2 price, which show a smoother but more long-lasting effect on electricity prices.

Increases in electricity prices in the short term also negatively affect the competitiveness of industrial sectors and tend to reduce household consumption. On the other hand, investments in clean energy generate a positive impact on employment, amplified on a wider economic scale through multiplier effects. The bulk of the carbon revenues can be used to fund RES and energy efficiency projects, reducing the financing costs. Clean energy investments and efficient allocation of carbon revenues have the potential to neutralize the negative impacts of carbon pricing in the EnC CPs. Therefore, average GDP growth in the decarbonisation scenarios is only marginally lower compared to the baseline case, which does not assume any form of regional CO_2 pricing.

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