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IMPACT ASSESSMENT REPORT

[European Grids Package]

Accompanying the documents

Proposal for a REGULATION OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL on guidelines for trans-European energy infrastructure, amending Regulations (EU) 2019/942, (EU) 2019/943 and (EU) 2024/1789 and repealing Regulation (EU) 2022/869

Proposal for a DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL amending Directives (EU) 2018/2001, (EU) 2019/944, (EU) 2024/1788 as regards acceleration of permit-granting procedures

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1. INTRODUCTION: POLITICAL AND LEGAL CONTEXT

1.1. Political context

Energy network infrastructure plays a crucial role in reinvigorating European competitiveness, ensuring the security of our Union and in the energy transition and decarbonisation. At the same time, the development of energy networks is confronted with new and significant challenges.

Electricity grids will need to serve growing demand linked to clean mobility, heating and cooling, electrification of industry, data centres and the ramp-up of the hydrogen system. Electrification of final energy consumption should increase from around 23% currently to around 32 % in 2030.[1] Member States should aim for an electricity interconnectivity level of 15% by 2030.[2] Networks will need to integrate 2.2-2.4 TW of renewables capacity to meet 2040 EU targets.[3] Grids will need to adapt for the EU to have a more decentralised, digitalised and flexible electricity system with millions of rooftop solar panels and local energy communities sharing resources. By 2040, electricity transmission and distribution grids will require investments of EUR 1.2 trillion and hydrogen networks of EUR 240 billion.[4] Offshore renewables alone should increase by up to 360 GW by 2050[5], which need to be connected to shore including through necessary onshore grid reinforcements. **Hydrogen will be important in decarbonising industrial and transport processes where electrification is not an attainable solution**. Hydrogen networks will connect production and demand centres across Europe, where on-site hydrogen production is not feasible.

The **Draghi report**[6] called for simplifying and streamlining permitting and administrative processes as well as for a coordinated strategic approach to cross-border infrastructure development between the EU and Member States. The **Council** invited the Commission to propose a strengthened framework for grid planning and rollout to be compliant with EU targets.[7] In its Conclusions of 16 June 2025[8], the Council called on the Commission to propose a grids package consisting of measures to, inter alia, simplify EU rules on grids, integrate EU-level, regional and national needs, ensure the delivery of projects, develop effective cost sharing mechanisms for cross-border projects of common interest, and assess the need for further legislative proposals to accelerate permitting of energy infrastructure. The **European Council** in its Conclusions also called for Union-wide long-term investment planning to fully integrate and interconnect the EU electricity market, contributing to the Union's energy security, and infrastructure protection and resilience.[9] The **European Parliament** highlighted the importance of modernising and expanding grids, as well as investment into digitalisation, with a focus on integrated cross-sector and cross-level planning.[10] It also

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[1] Clean Industry Deal COM(2025) 85 final
[2] Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action
[3] COM(2025) 524 final: Proposal for a Regulation establishing the framework for achieving climate neutrality
[4] Artelys, LBST, Trinomics, Finesso, A. et al., Investment needs of European energy infrastructure to enable a decarbonised economy, 2025; investment needs for distribution grids alone amount to EUR 730 billion.
[5] https://energy.ec.europa.eu/news/member-states-agree-new-ambition-expanding-offshore-renewable-energy-2024-12-18_en
[6] https://commission.europa.eu/topics/eu-competitiveness/draghi-report_en#paragraph_47059
[7] Energy Council Conclusions of 30 May 2024 on Advancing Sustainable Electricity Grid Infrastructure, 10459/24
[8] Council of the European Union, 10279/25
[9] Conclusions of the European Council of March 2025 EUCO 1/25
[10] European Parliament resolution of 19 June 2025 on electricity grids (2025/2006(INI))

emphasises cross-border infrastructure as a condition for successful deepening of the single market and for increasing the Union's resilience.[11]

This initiative responds to the Commission's commitment in the **Action Plan for Affordable Energy**[12] to propose a European Grid Package. It should consist of legislative and non-legislative measures to, among others, simplify the trans-European energy networks (TEN-E) Regulation; ensure cross-border integrated planning and delivery of projects, especially on interconnectors; streamline permitting for renewable energy generation, grid, storage infrastructure, and recharging stations for cars and trucks[13]; enhance electricity distribution grid planning; accelerate the ramp-up of the hydrogen market; boost digitalisation and innovation and increase visibility of manufacturing supply needs. It builds on the 2023 **EU Action Plan for Grids**[14] that focused on implementing the agreed legal framework to strengthen Europe's energy networks, and on the 2022 **Digitalisation of Energy Action Plan**[15] that promoted electricity grid digitalisation.

This impact assessment addresses possible legislative measures for the Grids Package, focusing on grid planning and development for transmission and distribution grids with a cross-border dimension, cost-sharing mechanisms, as well as permitting-related measures covering energy infrastructure, renewable energy generation, storage and recharging stations. It also addresses possible legislative measures to improve the security and resilience of energy infrastructure. The initiative would entail a revision of the TEN-E Regulation on cross-border energy infrastructure, targeted amendments to the revised Renewable Energy Directive (RED) to accelerate permitting procedures for renewable energy, related grids and energy storage, as well as recharging stations. In addition, it would entail limited targeted amendments to the Electricity Directive and Regulation as well as the Gas Directive and Regulation to ensure full alignment and legal coherence as regards the framework for permitting procedures at EU-level. In view of ongoing implementation measures, planning and access to distribution grids[16] and resilient supply chains[17] will be mainly covered through non-legislative measures to be set out in a Communication and in a guidance document on grids connection[18] as part of the Package. In addition, the Commission will come forward with sectoral tripartites on offshore wind and grids as well as on energy storage by the end of this year which will also address supply chain constraints.

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[11] EP resolution of 7 May 2025 on a revamped long-term budget for the Union in a changing world (2024/2051(INI)),
[12] COM(2025) 79 final
[13] Excluding recharging stations in residential and non-residential buildings, already covered by provisions in the Energy Performance of Buildings Directive, as amended by Directive (EU) 2024/1275.
[14] COM(2023) 757 final
[15] COM(2022) 552 final
[16] In view of the recently revised legal framework on grid planning, grid capacity transparency and incentives for smart and digital technologies, and the upcoming (legally binding) network code on demand side response, which will address distribution grids, as described in the Annex 6, no additional legislative changes concerning network planning or smart technologies on DSO level are proposed in the TEN-E revision, which addresses cross-border infrastructure including smart electricity grids. The transposition and implementation of the existing framework and upcoming network code will address the main challenges at distribution level for non-cross-border needs, including with regard to the sufficient grid capacity for connection of industry, automobile sector and data centres for AI. In addition, in view of the revision of the Governance Regulation and the transformation of NECPs into strategic investment plans, the Commission will assess whether additional targeted action is required.
[17] Building on the existing legal framework such as the Net-Zero Industry Act and ongoing measures of the Grids Action Plan as well as the EIB Grids Manufacturing Package.
[18] As announced in the Automotive Action Plan, the Commission will present as part of this initiative a guidance on grid connections to equip Member States with sufficient tools to manage grid connection requests more effectively.

1.2. Legal context

The TEN-E Regulation[19] lays down rules for the timely development and interoperability of trans-European energy networks to achieve the EU's energy objectives. The TEN-E Regulation was revised in 2022 to fully align its scope with the European Green Deal. The TEN-E Regulation is aligned to the provisions of the Electricity Market Regulation[20] and Directive[21], the hydrogen and gas decarbonisation package[22] as well as the Renewable Energy Directive (revised RED)[23]. The Electricity Market Regulation and Directive set rules for network planning at national level and their efficient use as well as incentives for the use of smart and digital technologies and on grid access and transparency.

The Gas Regulation, the Gas Directive and the revised RED, constituting the main pillars of the EU's regulatory framework for hydrogen, aim to enable the integration of renewable and low-carbon gases in the gas system to create a competitive EU hydrogen market and infrastructure. The gas and hydrogen legislative framework brings important policy considerations that require close alignment in the TEN-E Regulation. ENTSO-E, ENTSOG and ENNOH[24] respectively, are required to adopt and publish biennially non-binding Union-wide ten-year network development plans (TYNDPs) to, among others, identify investment gaps, in particular with respect to cross-border capacities.

The revised RED, as amended in October 2023, sets the permitting framework for renewables, related grids and co-located storage, as well as spatial planning requirements for renewable energy generation, grids and storage infrastructure.

The existing legal framework is in detail elaborated in Annex 6 and the Implementation Report (Annex 7) takes stock of its implementation.

1.3. Synergies with other EU policy instruments

The Grids Package is complementary to other initiatives that aim to create a more integrated European energy market. Energy infrastructure is crucial to achieve the proposed 2040 EU climate target.[25] The Commission proposal for the new Multiannual Financial Framework (MFF) 2028-2034[26] highlights "the vital importance of a genuine Energy Union and well-integrated EU infrastructure networks", which is reflected in a substantially increased budget proposed for the Connecting Europe Facility (CEF) for Energy[27]. The TEN-E Regulation provides the basis for energy infrastructure projects funded under CEF.

The Grids Package aims to support the goals of the electricity market legislation by ensuring that infrastructure brings additional socio-economic welfare and to further strengthen efficient use of existing infrastructure. The forthcoming Clean Energy Investment Strategy will cover the future framework for the financing of energy investment. Possible measures to enhance electricity

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[19] Regulation (EU) 2022/869 of 30 May 2022 on guidelines for trans-European energy infrastructure
[20] Regulation (EU) 2019/943 on the internal market for electricity (recast) (OJ L 158, 14.6. 2019, p.54)
[21] Directive (EU) 2019/944 on common rules for the internal market for electricity (recast) (OJ L 158, 14.6.2019, p. 125).
[22] Regulation (EU) 2024/1789 on the internal markets for renewable gas, natural gas and hydrogen and Directive (EU) 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen
[23] Directive (EU/2018/2001) on the promotion of the use of energy from renewable sources (RED), as amended by Directive (EU/2023/2413)
[24] As of January 2027. Until then the planning task remains with ENTSOG – Article 58 Regulation (EU) 2024/1789
[25] COM(2025) 524 final: Proposal for a Regulation establishing the framework for achieving climate neutrality
[26] COM(2025) 570 final: The Multiannual Financial Framework 2028-2034
[27] COM(2025) 547 final: Proposal for a Regulation establishing the Connecting Europe Facility for 2028-2034

interconnection targets enshrined in the Governance Regulation will be assessed as part of the revision of that Regulation and measures to further support the necessary national investment levels in energy infrastructure. The Grids Package will also complement the Environmental Omnibus proposal that is due end of this year, by proposing complementary sectorial measures that do not preclude the need and utility of the measures under the omnibus.

The 2026 revision of the EU Energy Security Framework will address energy security horizontally, complementing the network specific approach under this initiative. The security-related measures under this initiative also align with and build on the requirements of the horizontal security legislation, including the EU Critical Entities Resilience Directive, the NIS 2 Directive and the Network Code on sector-specific rules for cybersecurity aspects of cross-border electricity flows, and support its objectives and implementation. The Industrial Decarbonisation Accelerator Act will include measures to accelerate permitting of projects to decarbonise energy-intensive industries. Having sufficient grid capacity and timely grid connection is crucial to electrify industry, hence both initiatives are developed in close cooperation.[28] The initiative also complements the Trans-Mediterranean Renewable Energy and Clean Tech (T-MED) Initiative and the Pact for the Mediterranean.

In view of the planned Carbon Capture, Utilisation and Storage (CCUS) Package, the Grids Package will not address carbon dioxide cross-border infrastructure planning. Given a strong link between network planning on a national, regional and local levels and the heating and cooling sector, the recent revision of the Gas Directive requires stronger coordination among sectors. The Grids Package aims to build upon these requirements. In addition, the upcoming Electrification Action Plan and the Strategic Roadmap on Digitalisation and AI in the energy sector as well as the Heating and Cooling Strategy will provide important input for future grid planning. The Package also underpins the Cloud and AI Development Act to attract investment in data centres.

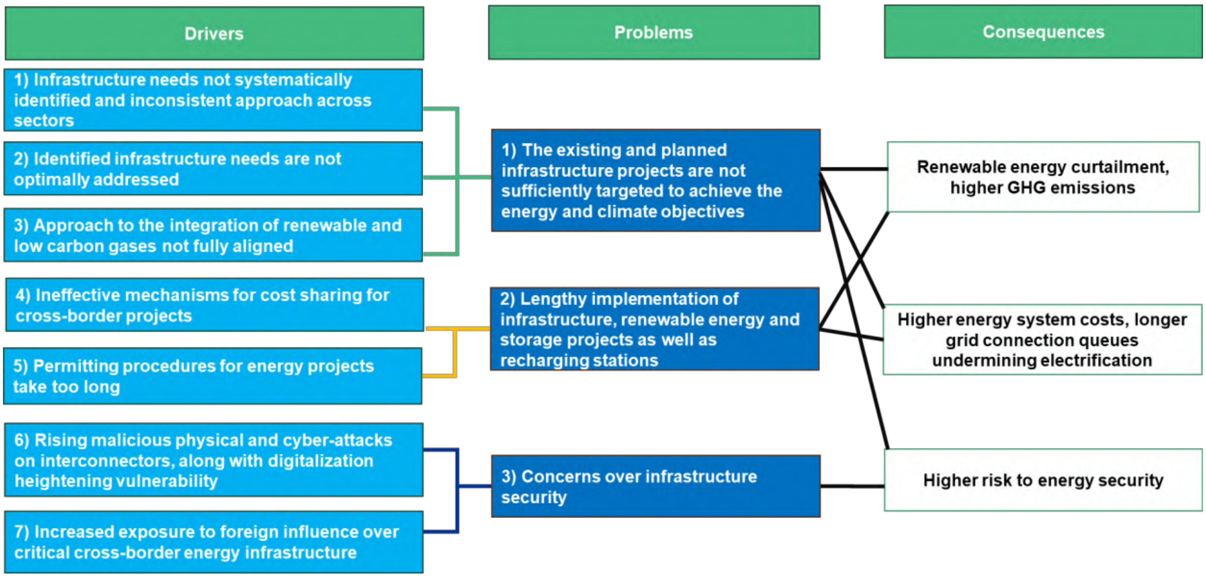
2. PROBLEM DEFINITION

2.1. What are the problems?

The key problems, corresponding drivers and consequences that are relevant for the Grids Package are presented in Figure 1.

[28] For instance, the needs of industry in terms of energy consumption should be well reflected in national network development plans and, vice-versa, there is a need for recognition of infrastructure planning in industrial policy considering the need for grid and pipeline infrastructure for H_2 and CO_2.

Figure 1: Problem tree



The revised TEN-E Regulation entered into force in 2022, and the revised RED was last amended in 2023 with some, but limited, experience on their implementation and impacts. Despite the recent revision of the TEN-E Regulation, however, the Implementation Report (Annex 7) demonstrates deficiencies in the current framework, in particular as regards scenario development, infrastructure needs identification, cost-sharing arrangements and the permitting framework for PCIs and PMIs. Besides the Implementation Reports (Annex 7), the analysis of the problems and their drivers relies mainly on most recent evidence, including ACER reports, ENTSOs' TYNDP data and assessments, JRC modelling as well as relevant input from stakeholders and the public consultation on the Europeans Grids Package (Annex 2).

2.1.1. *Problem 1: The existing and planned infrastructure projects are not sufficiently targeted to achieve the EU's energy and climate objectives*

There is a **substantial gap between our cross-border electricity infrastructure needs** for the energy transition and **the speed and level of infrastructure development**. According to ACER[29], half of cross-border electricity infrastructure needs for 2030 (32 of 66 GW) have not been addressed under the 2022 TYNDP. The gap is even higher for 2040: 37 GW of 90 GW needed will not be addressed through the current project plans.

The 2024 TYNDP found that the cross-border infrastructure needs have grown, amounting to 88 GW by 2030 and 108 GW by 2040, and that the 2024 TYNDP projects would still be insufficient to fully address needs, indicating the revision of the TEN-E Regulation in 2022 did not sufficiently ensure infrastructure needs are addressed.[30] Furthermore, ACER points to a mismatch in relation to investments included in the 2022 TYNDP, where capacity needs across certain borders are neglected, but others surpass the identified needs.[31]

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[29] ACER (2024): Electricity infrastructure development to support a competitive and sustainable energy System (2024 Monitoring Report)
[30] ENTSO-E (2025), TYNDP 2024. Opportunities for a more efficient European power system by 2050. Infrastructure Gaps Report.
[31] ACER (2024): Electricity infrastructure development (2024 Monitoring Report)

Shortcomings in the planning framework lead to investment falling short of the identified needs. Stakeholders (59%) in the public consultation on the Grids Package highlighted insufficient financing as a key barrier to developing grid infrastructure at the necessary pace for the energy (see Annex 2). In addition to insufficient cross-border capacity, planned network developments for transmission grids (one quarter of required investments) and distribution grids (over half of required infrastructure investments)[32] at national level also risk being insufficient for the energy transition.[33] Failing to address electricity infrastructure needs could exacerbate system congestion, both within and between Member States, limiting the capacity to integrate renewable energy sources, industries and businesses, thus impeding system decarbonisation. The shortfall in infrastructure development may undermine security of supply by creating bottlenecks, potentially leading to further market fragmentation and higher energy prices.

As an example, average day-ahead prices in Europe in the period of July to September 2024 at 17:00 UTC showed a price difference of EUR 265/MWh between Finland and Greece (Greece being 6.5 times more expensive).[34] Underlying reasons for price differences within the EU include the lack of flexibility in certain regions, inefficient use of existing grid capacity and insufficient physical interconnection. Price differentials are not only caused by insufficient cross-border connection, but also insufficient national transmission infrastructure. Only two Member States were constantly meeting the 70% Margin Available for Cross-Zonal Trade (MACZT) rule in 2023.[35] ACER[36] pointed out that most limiting factors for cross-border capacity allocation are related to internal bottlenecks.[37]

In addition to insufficient transmission capacity, the existing power system is not optimally used. Smart grid technologies are insufficiently used by TSOs and DSOs. Implementation of such technologies is closely linked to network planning and these solutions have significant potential of freeing available grid hosting capacity at lower cost and more rapidly than infrastructure solutions. Hence, their non-consideration carries a risk of higher cost for end consumers.

The **costs of an insufficient or suboptimal energy infrastructure are substantial**. The cost of congestion already reached EUR 4.2 billion in 2023[38], a yearly increase of 14.5%, and costs for renewables curtailment amounted to EUR 7.2 billion in 2024 in 7 countries alone[39]. Increasing queues of connection requests delay the integration of lower cost renewable energy generation,

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[32] Artelys, LBST, Trinomics, Finesso, A. et al., *Investment needs of European energy infrastructure to enable a decarbonised economy*, 2025.
[33] Ember (2024): Putting the mission in transmission: Grids for Europe's energy transition
[34] ACER (2025): Market monitoring report, Key developments in European electricity and gas markets - 2025
[35] Pursuant to Article 16 of Electricity Market Regulation (2019/943), 70% of transmission capacity after deduction of contingencies / respecting operational security limits shall be allocated for cross-border trade. Derogations are granted by NRAs for individual TSOs on a national level.
[36] ACER (2024): Market monitoring report, Transmission capacities for cross-zonal trade of electricity and congestion management in the EU.
[37] For instance, in the period between June 2022 and December 2023, in Romania, Germany and Slovakia, internal network elements were responsible for 99%, 82% and 77% of capacity constraints respectively. Network planning for internal infrastructure can hence significantly impact implementation of the internal market rules.
[38] ACER (2024): Market monitoring report
[39] How Europe's grid operators are preparing for the energy transition, Ember, E3G, Beyond Fossil Fuels, Institute for Energy Economics and Financial Analysis report, 2025. Note: these costs are broader than redispatching as referred to by ACER and may concern also economic losses of respective power pants operators linked to curtailment.

the electrification of the transport sector (charging points) and electrification of industry. In 2024-2025, 1,700 GW of renewable energy and hybrid projects were waiting for grid connections.[40]

The **development of the hydrogen sector**, especially electrolysis, will impact the power system both in terms of planning and operation.[41] ACER's 2024 European hydrogen market monitoring report[42] called for **more accurate demand forecasting during the planning phase, along with proper monitoring and adjustments during implementation** to avoid infrastructure oversizing and underutilisation. At the same time, industrial projects frequently lack timely access to hydrogen infrastructures and affordable hydrogen, pointing at the importance of timely and sufficient grid expansion combined with early and accurate communication of industrial needs. There is a strong link between network planning at national, regional and local level, requiring strong coordination among sectors – electricity, gases including hydrogen, but also transport and heating and cooling sectors, where relevant. Not considering mutual interlinkages between sectors and planning levels leads to sub-optimal planning.

2.1.2. Problem 2: Lengthy implementation of infrastructure, renewable energy and storage projects as well as recharging stations

Lengthy project implementation contributes to the gap in necessary electricity grid developments. Delays jeopardise the connection of new industries and businesses, the electrification of existing ones, it increases the risk and cost of new affordable energy generation projects, in particular from renewable energy sources, and, ultimately, it impacts the energy costs paid by consumers, including industrial decarbonisation projects.[43] The implementation of transmission and distribution infrastructure projects takes several years, during which they can come across challenges resulting from economic, technical and administrative complexities. The completion of electricity infrastructure projects takes 3.5-7.5 years for distribution grids and 7-10 years for transmission grids[44].

Long delays increase overall project costs due to increasing inflation, higher capital cost due to uncertainties in projects realisation, higher prices of supplies due to global market uncertainties, interest rate, lack of revenues if the commissioning of a project is delayed due to slow permitting, and penalties for not meeting deadlines. Supply chain constraints are also often mentioned as cause of delays, including in in the public consultation (Annex 2).[45] Manufacturing industry points to lack of visibility and certainty of project execution making it challenging for offtakers to commit to producers.[46] The Commission has adopted several initiatives to address supply chain constraints and the availability of skilled workforce in recent years including the Net-Zero Industry Act and ongoing measures of the Grids Action Plan, and the EIB has adopted a dedicated Grids Manufacturing Package.

Renewable energy and storage electricity projects, as well as recharging stations, also face delays, which hinder their fast deployment and risk jeopardising the achievement of the RED targets. While the pace of new installations has accelerated in the last years, it still falls short of the level required to achieve the EU climate and energy objectives and progress is uneven across

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[40] Beyond Fossil Fuels, E3G, Ember and the Institute for Energy Economics and Financial Analysis, How Europe's grid operators are preparing for the energy transition (2025). REPORT_FINAL.pdf, pg 5
[41] ENTSO-E (2025): Impact of Renewable Hydrogen in the Power System:
[42] ACER (2024) European hydrogen markets, 2024 (Market Monitoring Report)
[43] ENTSO-E and Renewables Grids Initiative, Value of timely implementation of "better projects", May 2019
[44] European Court of Auditors (2025): Review 01/2025: Making the EU electricity grid fit for net-zero emissions
[45] Building the future transmission grid – Strategies to navigate supply chain challenges; IEA, February 2025
[46] T&D Europe policy recommendations "Towards future-proof grids", July 2024

Member States. In 2023, the EU achieved 24.5% renewables share in total final energy consumption, ranging from 11.6% to 66.4% depending on the Member States. In 2024, new renewable energy capacities installed in the Union reached 78 GW, still falling short from the KPI set in the Clean Industrial Deal to install 100 GW of renewable electricity capacity annually up to 2030. However, even if the rate of deployment of renewable energy generation was in line with such objectives, renewable energy installations still face barriers for their effective integration into the system and their actual consumption in the Union's energy demand.

The Emergency Regulation[47], which included measures to facilitate the deployment of RES and grid projects, initiated during the energy crisis (2022-2023), accelerated renewable energy deployment in the EU, but progress is still insufficient. This remains the case despite the package of measures to accelerate permitting for renewables adopted in the revised RED. **Difficulties, and delays, in reaching agreements on cost sharing for energy infrastructure projects amongst potentially benefitting countries further postpone or halt investments**.

2.1.3. Problem 3: Concerns over infrastructure security

Recent incidents in the Baltic Sea, including those involving the Nord Stream 2 (September 2022), the Balticconnector pipeline (October 2023) and the Estlink 2 power cable (December 2024), highlight the **risk of hostile actors targeting energy infrastructure**. Likewise, **cyber-security incidents against energy infrastructure** have increased over the past years. Such targeted attacks pose substantial risks to the stability and resilience of our energy system. The outage of the Estlink 2 interconnector between Estonia and Finland in 2024 resulted in repair costs of EUR 30 million (and a loss in socio-economic benefits of EUR 94 million), and the second outage in 2025 in total repair costs of EUR 50-60 million[48].

Beyond deliberate acts of sabotage, there is an increasing recognition of the risks stemming from non-deliberate incidents, including natural hazards and climate-related impacts. This was noted by stakeholders in the public consultation: 38% of respondents agreed that the EU legal framework does not sufficiently addresses such emerging risks (Annex 2).

Whereas problems 1 and 2 lead to direct consequences in terms of renewable energy curtailment, higher greenhouse gas emissions, higher energy system costs as well as longer grid connection queues undermining electrification, problem 3 is linked to higher risks in terms of energy supply disruption which, if they occur, can endanger EU independence and lead to significant costs in terms of socio-economic welfare losses as well as political, social and economic disruptions.

2.2. What are the problem drivers?

The problem tree (Figure 1) illustrates how the drivers relate to the identified problem 1 to 3.

2.2.1. Driver 1: Infrastructure needs not identified and inconsistencies across sectors

Driver 1 relates to three root causes: weak scenarios as a basis of infrastructure planning, inconsistencies between different sectoral and regional/national infrastructure planning exercises, as well as lack of clarity on identified needs.

[47] Council Regulation (EU) 2024/223 of 22 December 2023 amending Regulation (EU) 2022/2577 laying down a framework to accelerate the deployment of renewable energy.
[48] Elering (2024): article

Scenarios not sufficiently robust: TYNDP scenarios constitute the first step for identifying the infrastructure needs as well as for assessing the benefits of projects. Despite the introduction of ACER framework guidelines[49] for the establishment of scenarios and the Commission approval of final scenarios, the current TYNDP scenarios have various shortcomings. They are subject to significant delays in each planning cycle[50] and assumptions are regularly criticised by stakeholders for being unrealistic, insufficiently transparent, not aligned with the NECPs, or even biased given the central role of the ENTSOs in this process[51]. The two-year cycles do not allow for sufficient time for effective feedback loops necessary to build robust scenarios.[52] This undermines the credibility of the infrastructure planning process and the robustness of needs identification and selection of priority projects.[53] In more than half of Member States, scenarios used by DSOs are not available (and not coordinated), impeding proper network planning.[54] Network planning cannot serve sufficiently for future connections, if it is not based on robust scenarios of future evolution.[55]

Inconsistencies between different levels and sector planning: The hydrogen and gas decarbonisation package strengthened cooperation between national transmission and distribution levels increasing consistency of related planning for electricity and gas, as well as other relevant sectors including heating and cooling. However, this national-level alignment does not avoid discrepancies between EU and national planning, as the scenarios used at the EU and national levels are not necessarily consistent.[56] **Insufficient cross-sectoral planning** on a European level risks an **inadequate assessment of infrastructure needs and the costs and benefits of individual projects**, which can entail substantial cost increases, e.g. through inefficiently high generation and back-up capacity expansions.[57] Several Member States' scenarios for network planning seem not aligned with the EU's 2030 targets.[58] On a national transmission level, planning is required only for a 5–10-year horizon, which may be insufficient given the lead times for transmission projects.

Not all infrastructure needs are properly identified and prioritised: The current identification of infrastructure gaps does not consistently analyse all potential infrastructure needs at national and EU level. There are substantial differences between electricity infrastructure needs identified for certain borders in respective planning cycles. Moreover, under the current 'bottom-up' approach (Annex 6), projects submitted by national TSOs and third-party project promoters for the EU-wide TYNDP are assessed as possible needs.[59] While this approach, by default, confirms the need for most of the proposed projects, it **fails to identify the optimal design of infrastructure**. In addition, the involvement of Member States, ACER and NRAs is limited in certain steps of the planning processes preventing validation of critical steps. The

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[49] ACER (2023): Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO-E and ENTSOG
[50] For more detailed assessment, see ACER Opinions on TYNDP, e.g. Opinion on ENTSO-E's draft TYNDP 2024
[51] ACER (2024): Opinion on the draft electricity ten-year network development plan
[52] Ibid.
[53] Sikow-Magny, Catharina (2025): Trans-European energy networks (TEN-E) – ideas for simplification in view of accelerating project implementation, RSC Policy Paper 2025/13
[54] ACER (2025): Guidance on distribution network planning
[55] Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networks
[56] ACER Opinion No 7/2025 on the electricity national development plans
[57] Agora Energiewende (2025): Integrated Infrastructure Modelling and Climate Neutrality, presentation at 11th Energy Infrastructure Forum, 3 June 2025
[58] Ember (2024): Putting the mission in transmission: Grids for Europe's energy transition
[59] Two categories of projects: "real" projects already investigated in the previous TYNDP cycle and "concept" projects with expected commissioning date after 2040 and with technical and economic parameters less certain.

public consultation indicated mixed views on the extent to which the TYNDP identifies all cross-border infrastructure needs, with 34% of respondents agreeing (companies 37%, business associations 33%, NGOs 14%, public authorities 20%).[60]

In the current TEN-E framework, **interconnections with a third country need to demonstrate significant benefits at Union level**. The PMI selection processes have shown that this criterion is difficult or impossible to fulfil for certain electricity interconnections, when their system benefits go mostly to the third country. This is of particular concern for **Energy Community countries including Ukraine and Moldova**, with whom interconnections impact the EU electricity market and may improve system stability and resilience. The framework does not account for benefits for the Energy Community of projects between EU and contracting parties.[61]

2.2.2. Driver 2: Identified electricity infrastructure needs are not optimally addressed

Driver 2 encompasses two root causes: identified infrastructure needs are not systematically followed up with possible projects and non-wired solutions are not considered as priority.

Not all identified infrastructure needs are addressed with possible projects, resulting in significant gaps: The TYNDP does not have a procedure to address cross-border or national gaps identified in ENTSO-E's infrastructure gap report. Consequently, new projects do not necessarily reflect what should be prioritised to fill the identified gaps. ENTSO-E identified 25 new projects in the 2024 TYNDP that aim to address a gap identified in the 2022 TYNDP. However, there remain borders where no new project has been proposed to address identified gaps. This was highlighted by stakeholders as part of the public consultation, where 44% of respondents (companies 37%, business associations 43%, NGOs 86%, public authorities 50%) indicated that the TYNDP process falls short in addressing relevant projects to close infrastructure gaps (see Annex 2).

Member States may be reluctant to support investments in new cross-border infrastructure due to national economic and political considerations. Even if a new interconnection project demonstrates overall welfare gains, it may contribute to higher wholesale prices in certain Member States due to price convergence across borders. In addition, consumers need to pay for the investments in new cross-border infrastructure through higher network tariffs. By contrast, the benefits in terms of generation surplus and congestions rents may only indirectly reach consumers. Thus, there may be a misalignment between national and EU-level incentives for a certain interconnection project which contributes to identified infrastructure needs not being optimally addressed.

The electricity planning framework at the EU and national level fail to make full use of non-wired solutions[62] as alternatives to grid expansions. While the TEN-E Regulation requires alternatives to grid development to be listed in the grid planning, there is no obligation to follow up with concrete projects, hence remaining rather ineffective.[63] While there is a requirement both

[60] 22% respondents expressed neutrality and 18% were uncertain.

[61] Experience from previous PCI and PMI assessment cycles proved interconnectors with Energy Community countries may not always fulfil the Union benefits criterion. While there is a dedicated process for Projects of Energy Community Interest (PECIs), it does not cover projects with the EU.

[62] For example, grid enhancing technologies, digitalisation or flexibility.

[63] See Annex 7 for more details on limited uptake of these solutions by TSOs. In the last two PCI/PMI selection procedures, only one project involving a TSO was submitted to support the digitalisation of existing grids.

for transmission and distribution grid planning to include flexibility and demand response, there is no explicit requirement to first consider non-wired alternative solutions, accompanied by a CBA.[64]

For **internal transmission**, the TEN-E Regulation requires projects to provide at least 500 MW impact in terms of cross-border capacity increase to prove their cross-border relevance. This threshold introduced in 2013 does not fully reflect the state of play of the EU electricity market where the average physically used capacity of interconnectors in Europe is 417 MW[65] per border between two countries. Therefore, the current threshold requires more than 100 % increase in average cross-border capacities. There is hence a risk that (smaller) projects which could increase capacities for cross-border trade are not adequately identified and supported. For **smart electricity grids**, while the last TEN-E revision simplified the rules for application of new project proposals, the number of project applications has not increased significantly.

2.2.3. Driver 3: Approach to the integration of renewable and low carbon gases not fully aligned with recent policy updates

Blending of **hydrogen** with natural gas risks diverting limited, costly renewable or low-carbon hydrogen from its priority use as a feedstock for industry and air and maritime transport, which cannot use blends. Blending poses challenges for gas quality, adaptation of equipment, and cross-border exchanges. Due to the high hydrogen costs compared to its energy value, blending increases costs for industry and households, and risks cross-subsidisation between users that benefit from injection or delivery and the users bearing the system costs.

These considerations have underpinned an evolving policy landscape, which is in particular reflected in the 2024 Gas Regulation and Directive. These legal acts consider that the production and use of hydrogen in its pure form and its transportation in the dedicated hydrogen system should be prioritised over the blending of hydrogen into the natural gas system which should be a last-resort solution (Annex 6). Yet, the vast majority of projects submitted in the 2023 and 2025 PCI selection process in the smart gas grid category aimed at high levels of hydrogen blending. Beyond issues of consistency with the latest policy developments, these projects also raised issues of interaction with Article 31 of the TEN-E Regulation, which enshrines the principle that for dedicated hydrogen assets converted from national gas assets, the transport or storage of a predefined blend should only be allowed for a transitional period ending on 31 December 2029.

As for the integration of **biomethane**, it is produced locally and injected at distribution level. Therefore, **the cross-border impact of such projects is expected to be limited in most cases, or indirect**. The current legal criterion that a smart gas grid project must have significant cross-border impact is purely formal in that it requires the involvement or close association of at least two TSOs that ensure interoperability. This falls short of ensuring in all cases a tangible significant cross-border impact.

Finally, whilst the smart gas grid category of the TEN-E Regulation is aimed at investment in digital equipment and digital installations to smarten the natural gas network for enabling the integration of renewable gases, projects submitted for PCI status have included substantial network elements going beyond what is indispensable for the functioning of such equipment and installations. These projects pose a risk of “greenwashing” and circumvention of the discontinuation of support to natural gas grids as decided with the TEN-E revision in 2022.

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[64] Similar to NOVA principle in Germany: German TSOs and DSOs are obliged to firstly consider grid optimisation measures, such as use of non-wired alternative solutions, before further grid build-out. Glossar | Netzentwicklungsplan
[65] Analysis of maximum physical energy flows between respective EU borders for year 2024 (ENTSO-E data).

As for **electrolysers**, the current definition in the TEN-E Regulation — with a **minimum threshold capacity of 50 MW**— makes it **difficult to demonstrate any meaningful cross-border impact.** A substantial proportion of electrolysers that were PCI candidates for the Union list were planned for direct industrial use rather than fulfilling cross-border objectives (Annex 7), contrary to TEN-E Regulation.

2.2.4. Driver 4: Ineffective mechanisms for cost sharing for cross-border infrastructure projects

Driver 4 encompasses the root causes related to current practices of cost sharing and benefits materialising increasingly outside the host countries of energy infrastructure projects.

While the current EU framework already includes instruments to facilitate investments in such cross-border projects, **it has not been used very effectively**. The TEN-E Regulation establishes a cross-border cost allocation (CBCA) framework. The CBCA tool has, however, so far only been used for the process of applying for CEF grants.[66] Therefore, the CBCA framework has been applied to relatively few projects. In addition, the CBCA decisions have primarily followed a territorial cost allocation principle (or a 50/50 split between hosting countries), which does not ensure that costs are shared in proportion to benefits. Since 2014, fewer than 10% of CBCA decisions have resulted in cost allocations involving non-hosting countries.[67] Two main causes have been identified. First, non-hosting countries are often engaged too late, being presented with the results of the benefit distribution and the cost-sharing request without being involved in the actual assessment. Second, there are insufficient tools and incentives for non-hosting countries to engage in this process, creating the possibility of free riding. This was confirmed by the public consultation, with 38% of the participants (companies 40%, business associations 37%, NGOs 36%, public authorities 20%) agreeing that the CBCA framework is not fit for purpose[68] citing its complexity, lack of transparency, and failure to incentivise cooperation among non-hosting countries as key issues.

As cross-border infrastructure becomes more integrated, the number of projects with benefits occurring outside the hosting Member States is expected to increase. A growing number of projects show that benefits will increasingly occur beyond hosting Member States, for instance in relation to offshore cross-border or hybrid projects.[69] As a result, allocating costs solely based on the territorial principle may risk these projects being delayed or not materialising.

The TEN-E Regulation provides that PCI investment costs, when under the competence of NRAs in the Member States concerned, shall first be covered through congestion income[70] or other charges before any remaining costs are passed on to network users via network tariffs. However, in practice, both the application of congestion income and the resulting tariff impacts are confined to the hosting countries. This leads to a misalignment between where the costs are borne and where the benefits of the infrastructure are realised.

As for hydrogen infrastructure, there is currently no practical experience, given the early stage of hydrogen market development. The CBCA mechanism in the hydrogen sector will only

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[66] CBCA is a precondition for submitting applications for CEF grants for works related to regulated projects.
[67] ACER (2023): Overview of Cross-Border Cost Allocation Decisions; ACER CBCA Report
[68] 20% of respondents remained neutral and 35% expressed no opinion
[69] See ENTSO-E's results on the sea-basin cross-border cost-sharing assessment under TEN-E Article 15.
[70] Congestion income is the revenue generated when electricity prices differ between two bidding zones due to limited transmission capacity between them. It is defined by ACER as the revenue resulting from the capacity allocation in the single day-ahead and intraday market coupling.

become relevant once NRAs become competent for hydrogen infrastructure with the implementation of the hydrogen and gas decarbonisation legislative package.

2.2.5. Driver 5: Permitting procedures for energy projects take too long

Despite the introduction of permitting acceleration provisions in the energy *acquis*, important bottlenecks remain slowing down the permitting of infrastructure, storage and renewable energy projects and recharging stations. Electricity transmission grids take around 10 years for completion, of which permitting accounts for more than half of the time needed.[71] Permitting was ranked as the leading obstacle to ensuring Europe's grid develops as needed for the energy transition by 78% of respondents to the public consultation (Annex 2).

According to ACER's 2023 report on the progress of PCIs, the most reported cause for delayed implementation is a delay in the permit granting procedure. In 2023, 26% of **electricity PCIs** were delayed by on average 12 months against their initially planned commissioning date. This share was fairly stable since 2020 despite some progress reported in the most recent ACER report with permitting accounting for approximately 51% of the total implementation timeline.[72] The clarifications and added flexibility introduced in the 2022 revision of the TEN-E Regulation have not led to substantial acceleration of procedures. However, the impact of introducing new acceleration measures was evident from when the Regulation was first introduced in 2013, leading to substantial acceleration of permitting procedures and ensuring the permitting of most PCIs falls under the maximum duration of the regulation. As reported by ACER in 2020, the average duration of permit granting for electricity transmission PCIs is about 3 years where permitting started after the entry into force of the Regulation and 9 years where projects started before, indicating a marked reduction.[73]

Energy infrastructure projects often cover long distances involving many sections and authorities leading to challenges in terms of coordination among authorities and potential delays of implementation due to delays due to delays in permitting for sections of the project. In 7 Member States the permitting of these projects takes between 18 and 24 months, and in 11 Member States it takes over 24 months[74].. For 7 Member States the general duration of permitting procedures is unclear and often depending on the project type.

Similarly, **permitting of renewable energy projects** can take up to 9 years depending on the Member State and technology.[75] Storage installations can take from 1-7 years depending on the technology.[76] The permitting for construction or transformation of recharging stations along highways and in depots can take up to 2 years in some Member States.[77] In 2020-2021, administrative and grid-related obstacles made up about 46% of identified barriers to renewable energy deployment because of incoherent administrative systems among multiple authorities,

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[71] ACER (2024): Electricity infrastructure development to support a competitive and sustainable energy system, p. 18
[72] ACER (2025): Monitoring of projects of common interest and of mutual interest - 2025
[73] ACER, Consolidated Report on the progress of electricity and gas Projects of Common Interest (2020).
[74] Please note that the data collected does not allow to have a more granular view of permitting procedures taking longer than 24 months, as the figure of "over 24months" encompasses all durations above 24 months which may in certain cases amount to several additional years.
[75] Final report to be found here: Technical support for RES policy development and implementation – simplification of permission and administrative procedures for RES installations (RES Simplify) - Publications Office of the EU
[76] Fraunhofer Institute for Systems and Innovation Research ISI, et al., Study on energy storage, 2023,
[77] Information collected by EV charging organisations, notably ChargeUp Europe, Ionity and Milence

inadequate staffing in authorities, the duration of environmental assessments, public acceptance, limited digitalisation and data availability, administrative and judicial challenges.[78]

Important measures were adopted in 2022 and 2023 to address some of these root causes. In December 2022, an Emergency Regulation was adopted to accelerate permitting for renewable energy and related infrastructure projects,[79] which was partially prolonged in December 2023[80] until 30 June 2025. This Regulation introduced binding and optional measures to accelerate permitting in a directly applicable legal instrument, including amendments to EU rules on environmental impacts assessments, shortening of deadlines and identification of acceleration areas. Germany has made an extensive application of the measures in this Regulation, in particular the voluntary ones, which has resulted in a substantial acceleration of permitting. In 2024, Germany approved approximately 14-15 GW of additional installed onshore wind capacity[77], which represents an 85% increase compared to the previous year and which almost equals the total new installed wind capacity in Europe in the same year.

In 2023 the revised RED was adopted[81], with several measures to simplify and streamline permitting procedures, including simpler and shorter procedures, including targeted rules for specific types of projects such as repowering or small-scale installations; and new measures on spatial planning including the designation of acceleration areas where environmental impacts are lower and therefore procedures can be faster. Despite these recent measures, in 2025, the same permitting related bottlenecks were identified during the Implementation Dialogue on permitting held by the Commissioner for Energy and Housing on 11 June 2025. Moreover, in a recent report on the state of regions and cities,[82] one of the demands of regions and cities to Europe was the acceleration of permitting for renewables and they indicated administrative delays as one of the main obstacles to timely deployment that remains. At the same time, they asked the development of a harmonised EU-wide digital permitting system, which they believe reduce bureaucracy and support faster local approvals, echoing our proposal for further digitalisation and centralisation of the permitting procedures.

Several factors contribute to this. First, the revised RED did not address (or did only partially) all issues which delay permitting and integration of renewables, such as permitting for storage or recharging stations, public acceptance and digitalisation of procedures. Second, the revised RED included only some of the measures of the Emergency Regulation but lacks several important measures included therein which have ceased to apply, such as those to expand the priority of renewable energy projects beyond environmental aspects and to streamline compliance with certain environmental rules. Given the positive acceleration observed in Germany as a result of the application of the Emergency Regulation, the fact that the revised RED does not include all the measures of the Regulation calls for additional measures to ensure the necessary acceleration of renewable energy installations. Third, while the transposition dates for the relevant permitting provisions of the RED were July 2024 and May 2025, the available information shows varying results among Member States regarding implementation[83] and shortcomings in the application of

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[78] Technical support for RES policy development and implementation – simplification of permission and administrative procedures for RES installations (RES Simplify)
[79] Council Regulation (EU) 2022/2577 laying down a framework to accelerate the deployment of renewable energy
[80] Council Regulation (EU) 2024/223 amending Regulation (EU) 2022/2577 (RED)
[81] The transposition deadline for most of the permitting provisions of the revised RED was 1 July 2024 and for some 21 May 2025.
[82] European Committee of region, "The state of regions and cities EU annual report 2025" (October 2025): The State of Regions and Cities in the European Union | European Committee of the Regions
[83] Solar Power Europe, EU Renewable Energy Permitting: State of Play (2025) page 15

rules.[84] The full implementation of the existing framework is still ongoing, but the feedback received by stakeholders shows that even in Member States where the existing framework has been transposed and is being implemented, there are bottlenecks that hinder fast permitting and deployment of the renewable energy projects. These are connected to a degree with the first two reasons mentioned above. Therefore, the long permitting procedures causing a slow project implementation can be attributed not only to the lack of complete and correct implementation of the existing framework in Member States but also to issues that have not been addressed fully or partially in the current legal system.

Amongst the causes for lengthy permitting procedures, **environmental assessments** have been identified repeatedly as the step most prone to delays.[85] The Emergency Regulation and the revised RED introduced targeted measures to ease certain obligations stemming from EU legislation regarding environmental assessments, including through the introduction of the presumption of overriding public interest, exemptions from environmental impact assessment (EIA) for certain projects and by introducing deadlines for the permitting procedures including the environmental assessments. They did not, however, fundamentally address the way such assessments are conducted. Overall, the average duration of the EIA for projects in general (not renewable energy-specific) is estimated to be around 20.6 months[86], thus affecting the ability to comply with the permitting deadlines in the revised RED (Annex 6).[87] According to stakeholders, the legal framework for environmental assessments leaves room for ambiguity and different interpretations by Member States. This leads to iterative interactions with diverse authorities, in some cases requiring applicants to address different administrative bodies for different parts of the assessment and repeated demands for additional assessments. In some Member States, the timeline for the EIA is unclear lacking precise deadlines and subject to multiple requests for reassessments and additional assessments. In the public consultation, a majority of respondents supported simplifying and streamlining environmental assessments (Annex 2).

Further, inefficient and ineffective public participation processes, leading to opposition in the form of administrative and judicial challenges continue to contribute to lengthy implementation.[88] Despite the general obligation to promote **public acceptance** introduced in the revised RED, lack of public acceptance remains a primary barrier to renewable energy permitting and thus market uptake. Studies and stakeholders[89] highlight the importance of transparency, early engagement of the public, its procedural participation, and a fair distribution of benefits as central to public acceptance.[90] However, measures aiming to ensure meaningful and early public consultation have faced problems in implementation linked to doubts over their interpretation and the procedural phase in which the consultation is inserted.

Limited resources in national permitting authorities are regularly voiced as one of the main factors contributing to delays in permitting procedures. Permitting authorities often do not have enough staff to process applications and/or lack the necessary technical expertise, for instance to

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[84] https://webgate.ec.europa.eu/fpfis/wikis/spaces/respqa/overview

[85] Milieu, Bruggeman, V., Vona, L., Moreira, G. et al., *Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest* (2025)

[86] Based on data reported by Member States until November 2023.

[87] Collection of information and data on the implementation of the revised Environmental Impact Assessment (EIA) Directive (2011/92/EU) as amended by 2014/52/EU), final report, page 25.

[88] Milieu, Bruggeman, V., Vona, L., Moreira, G. et al., *Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest* (2025)

[89] Ibid.

[90] CAN Europe (2025); Fast & Fair Renewables & Grid (2025); Eurelectric (2025)

handle the unclarity of environmental requirements and land use conflicts. Smart grid projects are a common example of project types affected by such limitations. These projects are comprised of different decentralised assets and are routinely not considered as a single project by competent authorities. Further, permitting procedures for renewable energy projects often require multiple permits awarded by different authorities (either in parallel or subsequently) and the lack of coordination mechanisms is an important bottleneck slowing down procedures. Digital resources to process applications are underused by authorities.

Moreover, the **permitting rules for electricity storage under the revised RED have a narrow scope** only covering co-located storage and not storage in general or so called "hybrid projects" despite its increasingly important role for system flexibility. Similarly, a lack of clarity on permitting for recharging stations for electromobility is creating undue complexities and delays (Annex 4). While the Alternative Fuels Infrastructure Regulation (AFIR) regulates recharging stations, it does not include permitting procedures.[91] This hinders the fast deployment of recharging stations and in turn the uptake of electric vehicles, which can serve as important source flexibility in particular as smart and bidirectional charging grows.

Overall, the permitting regime of energy projects is a frontrunner in terms of accelerated procedures.. However, this advanced starting point implies that many of the measures planned or recently adopted in other sectors[92] are already in place in the energy sector. The current permitting framework has not addressed all necessary bottlenecks to remove permitting from being a key barrier to the timely deployment of the projects necessary to reach the EU energy and climate targets.

2.2.6. Driver 6: Rising malicious physical and cyber-attacks on interconnectors, along with digitalisation heightening vulnerability

The frequency and sophistication of hostile acts undermining the security of the EU have increased. Hybrid campaigns[93] targeting the EU have intensified, featuring acts of sabotage targeting critical infrastructure, including in the energy sector.

Increasing system digitalisation of the energy system, combined with the evolving geopolitical context, creates substantial risks for interconnectors to be exposed to cyberattacks and cybersecurity incidents. According to Eurelectric, cyberattacks in the power sector doubled between 2020 and 2022, with 48 successful attacks targeting Europe's energy infrastructure in 2022 alone.[94] Such acts of sabotage, which may form part of broader hybrid campaigns, represent a significant risk to the operational security resilience of the EU's energy infrastructure and the energy security of Member States, and may directly affect access to

[91] The EPBD includes provisions simplifying permitting procedures for recharging points in buildings.
[92] Past legislation with a permitting dimension: Renewable Energy Directive; TEN-E Regulation; Hydrogen and decarbonised Gas Directive; Net Zero Industry Act; Critical Raw Materials Act; Gigabit Infrastructure Act.
Planned proposals with a permitting dimension: Industrial Accelerator Act, part of the Clean Industrial Deal; Cloud and AI development Act, part of the 'AI Continent' initiative, Environmental Omnibus following the Communication "Competitiveness Compass for the EU"; Strategy for Housing Construction, part of the Affordable Housing Plan
[93] Hybrid campaigns are designed in a way that makes detecting and defending against them difficult. They are devised to remain below the threshold which could constitute or be perceived as an act of war. Countering hybrid threats is therefore a complex and constantly evolving challenge that the European Union, its member states and its partners are facing. Source: Hybrid threats - Consilium
[94] https://www.eurelectric.org/in-detail/cybersecurity-in-the-power-sector/

heating, electricity, and essential services. A substantial share of existing cross-border energy infrastructure needs to be upgraded to strengthen its resilience against such potential failures.

While the EU horizontal framework on protection of critical infrastructure and cybersecurity[95] is comprehensive, it has yet to be meaningfully integrated into the TEN-E framework. Implementation of the related rules and requirements are currently not monitored in the context of the PCI/PMI framework and the **TEN-E lacks the tools to operationalise its implementation in the EU cross-border energy infrastructure policy**, especially for existing infrastructure.[96]

2.2.7. Driver 7: Increased exposure to foreign influence over cross-border energy infrastructure

In recent years, there has been increasing interest from third country actors to invest in EU energy infrastructure, notably interconnectors. **While foreign investment can bring benefits such as increased financing options for capital-intensive projects, it can also increase the EU's exposure to energy security related risks such as disruptions or reduced reliability of cross-border flows**, in particular when such foreign investments originate from third countries with diverging geopolitical interests from the EU.

Foreign ownership or control over interconnectors can influence key decisions regarding infrastructure operation, maintenance and future expansion. This can be used to exert political or economic pressure, potentially compromising Member States' autonomy in managing their security of supply. For instance, operational decisions could be manipulated to create artificial bottlenecks, prioritise certain energy flows, or delay necessary maintenance or upgrades.

Regulated interconnectors are typically owned and operated by TSOs, who must be certified under the Electricity Regulation. If a TSO controlled by third-country interests requests certification, the NRA must notify the European Commission. While most regulated interconnector promoters are TSOs, certification only occurs at the stage of entry into operation. Therefore, TSOs may not be certified during the PCI/PMI application stage, and hence no assessment is possible. As a result, there is limited transparency regarding the ultimate beneficial owners of candidate PCI/PMI projects. Under the Foreign Direct Investment Screening Regulation,[97] the Commission can give an opinion to the Member State where a foreign investment is planned or completed for PCIs/PMIs if it believes the investment might affect these projects for reasons of security or public order. However, such information is not necessarily shared in the context of the TEN-E framework and cannot be taken into consideration in the PCI/PMI selection, which prevents this process from fully addressing potential security risks. Limitations in the current framework in this respect were to some extent also evident in the public consultation, in which only 14% of respondents indicated

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[95] The EU Critical Entities Resilience (CER) Directive 2022/2557 provides a framework for strengthening the resilience of critical entities operating critical infrastructure against all hazards. The NIS 2 Directive (EU) 2022/2555) establishes a unified legal framework to uphold cybersecurity in 18 critical sectors across the EU. It also calls on Member States to define national cybersecurity strategies and collaborate with the EU for cross-border reaction and enforcement. The Network Code on sector-specific rules for cybersecurity aspects of cross-border electricity flows.

[96] The Commission has proposed additional tools as part of the upcoming MFF under which financing of critical infrastructure protection would in the future be eligible, notably as part of the Union Civil Protection Mechanism, the Competitiveness Fund and National and Regional Partnership Plans.

[97] Regulation (EU) 2019/452 of 19 March 2019 establishing a framework for the screening of foreign direct investments into the Union. The Commission has proposed to revise this Regulation inter alia to ensure all Member States have a screening mechanism in place, see COM(2024)23 final.

that the framework addresses the exclusion of non-trusted actors from participating in critical infrastructure projects, and 45% being uncertain.

2.3. How likely is the problem to persist?

The problems and drivers are likely to become even more important in the short and mid-term.

Problem 1: Under the current framework the gaps in cross-border and related internal energy infrastructure will persist or further aggravate given the non-identification of infrastructure needs and/or projects to address them. The further electrification of the energy system combined with an increased share of renewable energy generation carries a substantial risk to further increase grid connection queues, renewable energy curtailment and overall system costs.

Problem 2: Adopted and planned initiatives such as the revised RED and the Hydrogen and Gas Package have tackled long permitting procedures for certain key projects. However, inefficiencies under the current permitting system[98] are expected to persist for PCIs and PMIs. Only a minority of Member States have made use of integrated or coordinated schemes leading to coordination delays and misalignment of permitting schedules and public consultations. Specifically for the permitting of renewable energy projects, the expected acceleration in their deployment, in line with the objectives of the revised RED, is already increasing the pressure on permitting authorities and is expected to increase the number of requests that such authorities will have to process. The permitting obstacles are expected to persist despite new rules still being transposed. Moreover, full implementation of the existing measures risks not addressing all the issues, particularly given the ambitious key performance indicators set in the Clean Industrial Deal of installing 100 GW of renewable energy yearly and reach an economy electrification rate of 32% until 2030. In addition, electricity infrastructure projects (other than PCIs and PMIs), storage (other than co-located storage), including pumped hydropower storage, and recharging stations, continue to be subject to different national or even local permitting provisions. Finally, under the current framework, investments will happen in a sub-optimal, uncoordinated manner at a higher cost, reinforced by the absence of effective cost sharing tools.

Problem 3: it is expected that the threats to physical and cybersecurity would rather increase without sufficient protection against possible incidents. The problem and possible consequences is reinforced by possible exposure to certain foreign investors.

3. WHY SHOULD THE EU ACT?

3.1. Legal basis

Article 170 of the Treaty on the Functioning of the European Union (TFEU) stipulates that the 'Union shall contribute to the establishment and development of trans-European networks', including in the area of energy infrastructure. In addition, the 'Union shall aim at promoting the interconnection […] of national networks'. The TEN-E Regulation is based on Article 172 TFEU, which provides for the legal basis to adopt guidelines covering the objectives, priorities and broad lines of measures envisaged in the sphere of trans-European networks as set out in Article 171. The guidelines are to identify PCIs that are necessary for making the TEN-E fit for purpose and set the conditions under which the EU may financially support the PCIs.

[98] Milieu Law and Policy Consultancy, Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest (2025)

Article 194 of the TFEU stipulates that the Union shall aim to promote the development of new and renewable forms of energy and in accordance with Article 192 of the Treaty on the Functioning of the European Union (ex. Article 175 TEC), to decide on actions in accordance with the Union policy on the environment. The revised RED is based on Articles 194 and 192 of the TFEU, which constitutes the legal basis to establish measures to achieve the objectives of climate neutrality and decarbonisation of the economy via clean energy technologies. The proposed measures relate to the fields mentioned above aiming to develop trans-European networks and promoting the faster deployment and integration of renewable energy (Annex 9).

3.2. Subsidiarity: Necessity of EU action

Energy transmission infrastructure and, increasingly, electricity distribution grids have a trans-European or at least cross-border nature or impact. The TEN-E Regulation has contributed to achieving results regarding the EU energy market integration, competition and security of supply. A framework for regional cooperation across Member States is necessary to develop cross-border energy infrastructure. National regulation and planning are not sufficient as individual national administrations do not have the power to deal with cross-border infrastructure planning. The internal network elements significantly influence the possibilities of cross-border infrastructure development, which in turn affects cross-border trade. More closely coordinating national and European planning is necessary due to the character of the EU's meshed network and to build a more efficient energy system. Further, as regards electricity transmission and distribution infrastructure, despite the recognised need to accelerate their development to integrate renewables into the system[99], there is currently no permitting acceleration provisions at the EU level that mirror those available to gases infrastructure in the Gas Directive.

Reaching the EU energy objectives without additional action on the RES deployment at EU level would not be cost efficient. An EU approach is needed to provide the right incentives to Member States to accelerate, in a coordinated way, the energy transition towards a more energy-efficient energy system largely based on renewables. The revised RED already includes provisions on permitting for renewables, co-located storage and related grids. EU action is needed to further improve that regulatory framework in a coordinated way, bringing faster permitting procedures for renewables, storage and recharging stations, ensuring alignment among Member States and the good functioning of the Energy Union.

3.3. Subsidiarity: Added value of EU action

The TEN-E Regulation has provided additional value compared to what could have been achieved at national or regional level alone. More than 100 projects were completed thanks to the PCI status between 2013-2025. The accelerated electrification, decarbonisation and digitalisation of industry and deployment of renewable energy projects call for the reinforcement of the energy infrastructure at an unprecedented pace, that cannot be met by national measures alone. More effective cross-border planning will improve the integration of clean energy sources as well as meeting electricity market needs, which would help the EU reach its energy and climate targets. A more integrated market encourages the development and uptake of innovative technologies for transmission and distribution of energy and contributes to system flexibility and security of supply. This can result in a more efficient network and improve cross-border trade for a more cost-efficient and secure energy system.

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[99] Communication from the Commission (2023): Grids, the missing link - An EU Action Plan for Grids

EU action on renewable energy under the revised RED brings added value because it is more efficient and effective than individual Member States' actions, avoiding a fragmented approach by addressing the transition of the European energy system in a coordinated way. It ensures net reduction of greenhouse gas emissions and pollution, protects biodiversity, harnesses the benefits of the internal market, fully exploits the advantages of economies of scale and technological cooperation in Europe, and it gives investors certainty in an EU-wide regulatory framework. By acting at EU-level in combination with action at Member State level, several barriers to public and private investments can be tackled supplementing and reinforcing national and local action.

4. OBJECTIVES: WHAT IS TO BE ACHIEVED?

The objective of the initiative builds on the general objective of the current TEN-E Regulation (Annex 7) but develops it further by including the related topic of the development of renewable energy, storage and recharging stations. By a stronger focus on ensuring efficient and effective infrastructure planning, extending the timeframe beyond 2030 as well as security of cross-border energy infrastructure, the revised general objective reflects the new political context.

4.1. General objectives

The general objective is the timely and efficient development and interoperability of resilient energy infrastructure, renewable energy and flexibility, including storage and recharging stations, across the EU. This will enable the EU to deliver on its energy and climate objectives, including ensuring energy affordability through better interconnectivity, leading to price convergence, reduced wholesale electricity prices and lower volatility of electricity prices, as well as to accelerated connection of generation and demand.

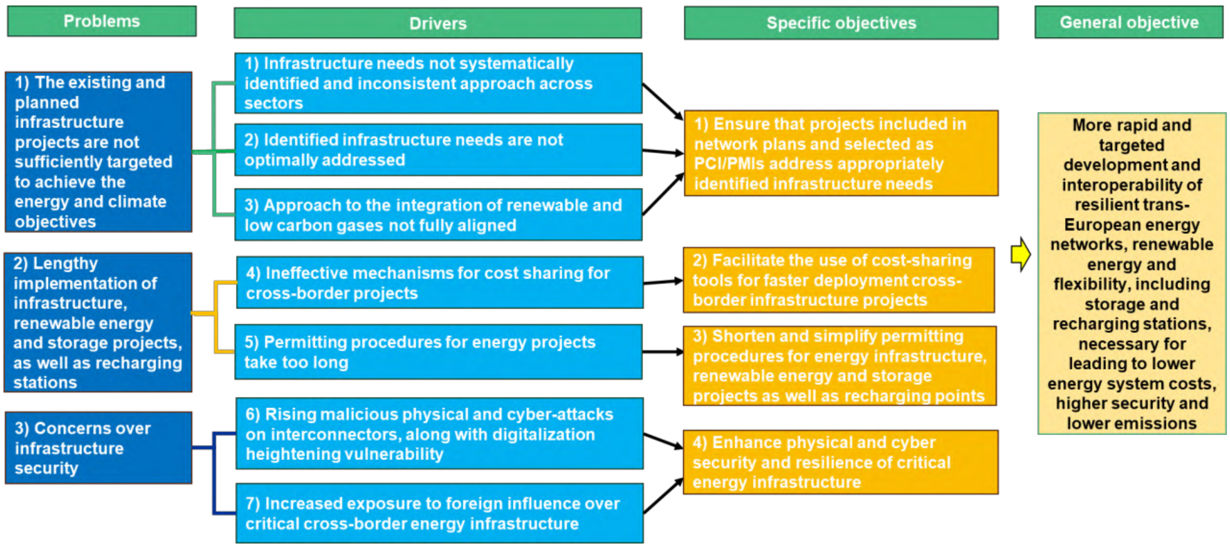
4.2. Specific objectives

The general objective can be disaggregated into four specific objectives, which are to be pursued by the policy options are to address the problems and underpinning drivers identified in Section 2, namely to:

- Ensure that projects included in network development plans and selected as PCI/PMIs address appropriately and effectively identified infrastructure needs ensuring timely and efficient development of energy infrastructure. The aim is to ensure clear matchmaking of projects included in network development plans with the identified needs. Selected PCI/PMIs projects should be assessed and validated based on clearly defined criteria, demonstrating that they effectively address infrastructure needs identified. This should lead to a reduction in the gap between planned infrastructure projects in the TYNDP and the identified cross-border infrastructure needs over time.
- Facilitate the use of cost-sharing tools for faster deployment of cross-border infrastructure projects, leading to an increased use of cost-sharing tools and a reduction in project deployment time.
- Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations, leading to shorter time to obtain necessary permits, making it feasible to meet the existing deadlines, and simplified permit requirements.
- Enhance physical and cyber security and resilience of cross-border energy infrastructure (PCIs/PMIs) by increasing the number of protection and resilience equipment and installations on critical network elements.

Figure 2 illustrates how the problem drivers relate to the objectives of the initiative. The last column indicates how the policy options (Section 5) relate to the problem drivers and objectives.

Figure 2: Problem drivers, specific objectives, and general objectives



5. WHAT ARE THE AVAILABLE POLICY OPTIONS?

5.1. What is the baseline from which options are assessed?

Under the baseline scenario, the TEN-E Regulation, the Electricity Directive, Electricity Regulation, the Hydrogen and Gas Package are assumed to continue to apply as currently in force (Annex 6). The proposal for an EU climate target 2040 and the possible revision of RED, the Energy Efficiency Directive as well as energy security framework should also be taken into account.

Regarding network planning and needs identification, the **frequency** of the TYNDP process (every two years) remains unchanged and the existing challenges in terms of delays in the process (scenarios, needs and project assessment) will likely continue to negatively affect the PCI and PMI selection process due to required input not being available on time. The infrastructure needs identification process remains primarily a bottom-up analysis. The granularity of the needs assessment remains the same. Uncertainties about completeness and robustness of the needs identified continue to be unaddressed. Acceptance and credibility of the results of the **TYNDP and the needs assessment likely remains weak** due to limited involvement of Member States or NRAs. While cross-border energy infrastructure will continue to develop under the current framework, it is expected to occur in a non-optimal manner due to the issues identified in section 2, therefore also failing to address growing grid congestion and renewable energy curtailment which could become as high as 310 TWh by 2040 in the BAU scenario.

With regard to cross-sectoral planning, once the gas package is transposed and implemented, it will provide for stronger cross-sectoral coordination. However, the implementation might be challenging, also due to **missing mirroring requirements** on the electricity side and **technical constraints** under the two-year TYNDP cycles. These requirements demand **national-level coordination** between TSOs and DSOs on scenario development across the electricity, hydrogen, and gas sectors as well as alignment with the NECPs and, where applicable, consideration of local heating and cooling plans, and alternative fuel infrastructure needs.

On **cost sharing**, the current TEN-E framework to facilitate cost-sharing agreements for cross-border infrastructure projects continues to apply. For PCIs/PMIs that have reached sufficient maturity to start the construction within 36 months, project promoters can submit an investment request, including cross-border cost allocation. Experience shows that the framework is unlikely to lead to cost-sharing agreements between hosting and non-hosting beneficiary countries.

On **permitting**, for energy infrastructure assets, the dedicated permitting requirements and acceleration provisions for PCIs and PMIs (TEN-E Regulation), and grid assets necessary to integrate renewables (revised RED), will continue to apply. Permitting for hydrogen infrastructure will start to be regulated with the transposition of the Gas Directive (deadline 2026). For the permitting of renewable energy and co-located storage installations, the baseline is the revised RED while there is no permitting framework for non-co-located storage and recharging stations. Implementation of these measures would be supported by the Commission through ongoing transposition checks and continuous engagement with Member States. While for renewable energy projects, co-located storage and their related infrastructure, the full transposition and implementation of the permitting framework under the amended RED is expected to bring some positive results, as explained in the problem section, this change will not be enough to meet our 2030 goals. The remaining issues in parts of the permitting procedures not touched upon before keep hindering the proper implementation of the permitting framework. This is in combination with an aligned permitting framework for grids, stand-alone storage and recharging stations, necessary for the integration of renewable energy, are a clear indication on the difficulty to be phased to reach our 2030 targets and KPIs only with the baseline scenario.

As for the **security of cross-border energy infrastructure**, the EU horizontal framework on protection of critical infrastructure and cybersecurity applies, notably the CER Directive and the NIS 2 Directive as well as the Network Code on cybersecurity. The TEN-E Regulation does not include provisions for addressing resilience against possible physical malicious acts and cybersecurity disruptions to cross-border energy infrastructure.

With regard to **electricity distribution grid planning**, the baseline option assumes that provisions in the draft electricity network code on demand side response, as submitted by ACER in March 2025, will be kept in the final text of the network code, to be adopted in 2026.[100] For grid connections, the baseline assumes relevant provisions of the Electricity Directive on grid hosting capacities transparency and flexible connection agreements are fully implemented. The Commission will support Member States and all relevant stakeholders in the implementation of existing legal provisions. This concerns exchange and sharing of best practices on grid planning, coordination among DSOs and TSOs, as well as smart and digital technologies. As these initiatives would be proposed and implemented regardless of the present package (Guidance on grid connections would be presented as committed in the Automotive Action Plan, as well as the strengthened options on DSO grid planning under network code), they form a part of the baseline against which policy options are assessed. Lastly, to support new smart electricity grid PCI candidates to be proposed, the Commission will engage in further communication and awareness efforts, inter alia with Member States, including for the integration of electrified industry, electromobility charging infrastructure, electrified heating and cooling and data centres, as long as a cross-border impact of the project can be demonstrated.

[100] The draft electricity network code contains provisions on coordination between electricity TSO-DSO and DSOs, methodology for planning and scenarios, link to flexibility needs assessment, use of local services as alternatives to grid development, monitoring of DNDPs and more transparency related to public consultation of electricity DNDPs.

Regarding **delays caused by supply chains related constraints**, the baseline assumes implementation of the existing legal framework and non-legislative actions: the Grids Action Plan, the Net-Zero Industry Act[101], the EIB Grids Manufacturing Package, and the Union of Skills.[102]

5.2. Description of the policy measures and options

Based on the consultation and desk research undertaken for this Impact Assessment, the Commission identified individual policy measures having the potential to address the problem drivers identified in the problem definition (Section 2) and achieve the specific objectives (SO) (Section 4.2). The policy measures were grouped into policy packages (Section 5.2.2).

The following process was applied for establishing the policy packages: (i) identifying the policy measures which can be discarded based on a first preliminary assessment; (ii) identifying a list of retained policy measures addressing the problems and respective problem drivers; (iii) combining retained measures into policy packages constituting viable policy alternatives for achieving all the objectives of the initiative.

5.2.1. Description of the policy measures

This section provides a summary of the identified policy measures to address the problem drivers and specific objectives. For further details see Annex 9.

A. Infrastructure planning and project implementation

Four policy measures were identified to respond to problem 1 (drivers 1-3) and SO1.

A.1 Strengthening the existing framework

Measure A.1 proposes limited changes to **strengthen the existing infrastructure planning framework**. It maintains most of the current responsibilities of the main stakeholders but better defines and strengthens certain existing requirements to ensure a leaner and more robust planning process. To simplify and streamline the PCI/PMI selection process, there would be a shift from the *ex post* opinions by the **Commission and ACER** as well as approvals on the draft scenarios and draft infrastructure gaps identification report developed by the ENTSOs towards *ex ante* steering through **strengthened ACER's and NRAs' roles** in the verification of the TYNDP inputs to the PCI/PMI process and in monitoring the implementation. Moreover, scenario-building should consider national developments as regards the development of industrial hubs for electrification, deployment of data centres, electromobility charging infrastructure, heating and cooling plans and the revised NECPs. It would also include a simplified application and evaluation process for mature PCIs and PMIs. In addition, the planning would be expanded to better consider **non-wired solutions and internal grid reinforcements** to ensure infrastructure needs are optimally addressed**.**

A.2 Increased EU level steering and coordination

Building on measure A.1, measure A.2. would entail moving from a bottom-up towards a top-down cross-border infrastructure planning approach ensuring **greater transparency, scrutiny and coherence of inputs used in network planning** both at EU and national levels. It involves the Commission, ACER and NRAs earlier in the planning process and simplifies applications for

[101] Regulation (EU) 2024/1735 on establishing a framework of measures for strengthening Europe's net-zero technology manufacturing ecosystem and amending Regulation (EU) 2018/1724
[102] Union of skills - European Commission

mature PCIs/PMIs. The Commission would be responsible for the development of a **comprehensive central scenario at least every 4 years** (instead of 2 years), with the possibility to conduct interim reviews in case of very significant changes, as a basis for a **strengthened, streamlined, more predictable and simplified infrastructure needs identification conducted by the ENTSOs and ENNOH** based on **framework guidance developed by ACER** in line with the principles defined in the TEN-E Regulation. Project collection and assessment for the TYNDP and the PCI/PMI selection process would continue to be conducted every 2 years. The central scenario would allow for better comparability of projects and their costs and benefits. It would be less driven by (national) TSOs, represented by ENTSOs, but rather by the Commission and the Agency with close involvement of all Member States ensuring network planning captures EU policy targets as well as Member States' perspectives and ensures alignment. There would be a closer link between the EU central scenario and national scenarios used in network planning, improving coordination between the EU and national levels of infrastructure development.

A new **gap filling mechanism** would be introduced to ensure that all needs are addressed by requiring the submission of project proposals by TSOs when the identified infrastructure needs are not being adequately matched by the project proposals submitted in the standard process for project collection for the Union-wide TYNDP. This should ensure that infrastructure needs are more optimally addressed reducing the gap over time. First, relevant TSOs would be required to propose possible solutions under the scrutiny of NRAs and Member States. Second, in case no projects are proposed, the Commission, in cooperation with hosting Member States, may launch a call for project proposals. For the electricity sector this option would introduce requirements to **better link national and European planning**. This measure would also prolong the period of network planning on a national transmission grid level for electricity from existing minima of at least 5-10 to at least 15 years. Measure A.2 would also require to fully consider **non-wired alternative solutions** as a priority when addressing the identified needs.

A.3 Fully centralised approach

Measure A.3 entails a full shift from the current bottom-up planning and needs identification approach to a full **top-down coordination and project selection at the European level**. The main activities of the scenario development, needs assessment and projects assessment under the TYNDP **for cross-border infrastructure** would be done by **an entity at EU level** (e.g. an EU energy agency) responsible of the entire planning process complementing national planning processes. Relevant national actors, such as system operators and regulators would still be involved, providing relevant information on local and national grid characteristics. The gap filling mechanism (see measure A.2) would also be steered by this entity. However, Member States would retain their right to veto any PCI/PMI candidate projects to be located in their territory in line with the TFEU, and would therefore have to approve projects in their territory

No existing entity would seem equipped with the necessary expertise, and this would therefore require the transformation of an existing one or the creation of a new entity. A transitional period would therefore be needed.

A.4 Alignment of scope (smart gas grids/blending, electrolysers, projects of mutual interest)

Measure A.4 involves strengthened requirements to ensure that **electrolysers recognised under the TEN-E have significant cross-border relevance**. This is achieved by increasing the installed capacity threshold of electrolysers projects eligible for PCI status from the current 50MW to 500MW. The changes cater for a better alignment of this category with the objectives of the TEN-E. To promote infrastructure dedicated to the exclusive use of hydrogen this measure **also removes any incentives for projects for blending hydrogen with natural gas**, including by removing the smart gas grid category from the scope of the TEN-E Regulation, removing the possibility of blending and amending definitions of ‘dedicated hydrogen assets’ and ‘repurposing’ to ensure these exclusively target pure hydrogen. Finally, candidate projects for **PMI** status with the **Energy Community** contracting parties would not need to demonstrate net benefits to the Union as long as all other criteria are fulfilled.

A.5 Broadening scope of PCI categories (modernisation and digitalisation)

Measure A.5 introduces a **change to electricity grids PCI category** to more prominently include **non-wired solutions** and better **acknowledge the role of internal lines** contributing to cross-border electricity trade (and flows), to enable optimal grid development.

B. <u>Cost and benefit sharing</u>

Four policy measures were identified to respond to problem 2 (driver 4) and SO2.

B.1 Enhancing transparency and strengthening EU principles for cross-border energy infrastructure costs and benefits sharing

Measure B.1. involves enhancing **early transparency** in the assessment of project benefits and costs to encourage the involvement of non-hosting countries. It also aims to establish a **streamlined CBCA process** and a more **harmonised EU cost-sharing framework**. It would require ENTSO-E and ENNOH to publish cost-benefit analysis results showing how the benefits of TYNDP projects are distributed across countries, including non-hosting countries who substantially benefit from such projects. **ACER would be mandated to update its recommendation** on the treatment of investment requests for PCIs and PMIs (or CBCA recommendation) based on CBCA principles outlined in the TEN-E Regulation.

B.2 Use of congestion income for financing of cross-border electricity infrastructure as an incentive to cost-sharing

Under measure B.2, congestion income is used to create an additional tool for unlocking cost-sharing discussions with the aim to increase the use of cost-sharing tools. The Commission would be empowered to provide detailed rules on the use of congestion income for financing cross-border electricity infrastructure under the Electricity Regulation. TSOs would be required to allocate a share of the congestion income to PCIs addressing the biggest bottlenecks in the European or regional energy systems. This should facilitate reaching agreements on cross-border cost allocation, particularly for projects that generate substantial benefits for Member States other than the host country.

B.3 Enabling framework for voluntary bundling of projects

Measure B.3. seeks to incentivise increased financial contributions from Member States towards cross-border energy infrastructure projects that generate benefits beyond their host countries by establishing an EU-level framework for the **identification and voluntary bundling of cross-border projects** to enable and encourage discussions amongst relevant Member States (and third countries). These projects would be grouped together to enable cost-sharing discussions amongst relevant Member States or third countries and facilitate joint PCI applications and access to CEF. While the voluntary bundling of projects is already possible in principle, certain legislative changes are required to allow for project bundles to fully benefit from the cross-border cost allocation provisions under the TEN-E framework. For instance, a new definition of project bundles would be introduced that would allow for specific references in the cross-border cost-allocation framework currently designed for project-specific PCIs/PMIs.

B.4 Mandatory offshore regional planning and cost-sharing

Measure B.4 introduces a mandatory regional planning for **offshore cross-border infrastructure projects** within sea-basins where hybrid or cross-border radials are already planned, building on existing processes in view of possible application in other areas.

C. Permitting

Three policy measures were identified to respond to problem 2 (driver 5) and achieve SO3.

C.1 Supporting the implementation of existing legislation and issuing guidance

Measure C.1 entails reinforcing policy efforts to **implement the current permitting acceleration framework** and adopting new non-legislative measures. It does not, however, introduce new legislative measures. The Commission would also support Member States to implement best practices. The Commission would issue or update guidance on the implementation of certain aspects of the environmental assessment framework for permitting procedures, support implementation via dialogue with Member States in dedicated fora such as CA-RES and may establish additional technical fora to address implementing barriers.

C.2 Targeted legislative changes to accelerate permitting

Measure C.2 involves **legislative amendments** to further accelerate and simplify permitting procedures for cross-border, national transmission and local distribution grids as well as renewable energy and storage projects and recharging stations. These amendments could include: (1) **establishing an EU level framework** for the accelerated permitting of electricity distribution, transmission and storage projects and recharging stations including alignment with and further strengthening of the EU level permitting provisions applicable to hydrogen infrastructure; (2) strengthening the permitting acceleration provisions of **the TEN-E Regulation**; (3) introducing changes in the **revised RED** with regards to the permitting framework, introducing a fast permitting framework for non co-located storage assets, and recharging stations, making permanent measures from the Emergency regulation and addressing any remaining shortcomings (that have not been addressed before or that have addressed only partially) that hinder permitting and compliance with the existing framework; (4) **simplifying and streamlining environmental assessments** applicable to energy assets; **exempting certain projects** due to their characteristics from certain assessments or elements thereof.

The **permitting measures** that are assessed as part of the Grids Package can be summarised as follows building on the description in Annex 9:

- Presumptions of **overriding public interest** for all PCIs/PMIs and temporarily for all transmission and distribution system infrastructure. Expanded scope of the presumption under the revised RED and deletion of the possibility of exemptions.

- **One-stop-shop**/single point of contact for electricity system infrastructure and **digitalisation and centralisation of procedures and data gathering.**

- **Time limits:** introducing (for electricity infrastructure, non co-located storage and recharging stations).

- Expand **tacit approvals** and introduce **exemptions from environmental assessments** (EIA, assessments under the Water Framework and Marine Strategy Directive).

- Make permanent measures of the Emergency Regulation for alternative tests and compensation measures.

- Introduce measures with regards to public participation and acceptance and **strengthen cross-border procedures** under the TEN-E regulation applicable to all PCIs.

- Introduce obligation of **adequate administrative resources** in the TEN-E Regulation, Electricity Directive and Gases Directive.

The proposed measures build on the acceleration measures introduced in previous sectorial initiatives to facilitate that these deadlines can be met, procedures simplified, and the lead time for permits is shortened. These elements would also ensure a better implementation of the EU rules for permitting at national level and by the different administrative entities involved, thus promoting the effectiveness of the different permitting frameworks.

Court proceedings are not under the scope of the permitting rules for renewable generation and grid infrastructure, for storage and charging stations projects, so no direct measures are proposed, but the measures on public participation aim at decreasing litigation and therefore delays by court proceedings. Furthermore, the Commission will deal with long and complex court proceedings via non-legislative actions, including discussions in the context of the Permitting Expert Group.

C.3 Centralised EU-wide permitting coordination regime for certain large-scale energy infrastructure projects

Measure C.3 would introduce a **centralised EU ("28th") regime for the permitting** of very large energy projects such as interconnectors and large-scale renewable energy projects with cross-border characteristics.[103] This would shift responsibility of coordinating permitting processes from Member States' one-stop shops to the EU through a **permanent European coordination authority**. National permitting authorities would retain a critical role in the permit granting procedure as projects have an impact on land use, property and the environment within their territory. The centralised EU coordination entity would liaise with national and local authorities to verify that the necessary approvals are granted on time, without having direct impact on the national procedures. A transitional period would likely be needed to set up and operationalise a new EU-level entity or expand the scope of an existing one.

D. Security

Three policy measures were identified to address problem 3 (drivers 6 and 7) and achieve SO4.

D.1 Including physical and cyber-risk resilience considerations in the monitoring of PCIs and PMIs

Measure D.1 would require project promoters to include **a risk assessment** as part of their implementation plan and, where needed, provide details on the envisaged physical and cybersecurity mitigation measures in their annual reports with the aim to enhance physical and cyber security and resilience of cross-border energy infrastructure (PCIs/PMIs).

[103] M. Draghi, "The future of European competitiveness – Part A | A competitiveness strategy for Europe", p. 50-51

D.2 Additional transparency requirements regarding the ultimate beneficial owners of candidate PCIs/PMIs

Measure D.2 introduces **transparency requirements** regarding the ultimate beneficial owners of all candidate PCI/PMI projects and their internal shareholder structure to address increased exposure to foreign investments. Project promoters would be required to share information about their ultimate beneficial owners during the TYNDP application process to be taken into account in the assessment of candidate PCI and PMIs.

D.3 Including security and resilience-related equipment for the upgrade of existing electricity cross-border infrastructure under TEN-E scope

Measure D.3 introduces the possibility to include **PCIs related to security upgrades** of existing electricity infrastructure under the TEN-E framework.

5.2.2. Description of the policy options

The measures described in Section 5.2.1 have been grouped in **3 policy options**. Table 1 provides an overview of the policy measures and their links with specific objectives and policy options. The design of policy options follows a logic of varying degrees of EU-level intervention and coordination in achieving the general and specific objectives.

The design of the policy options takes into account the compatibility of the respective policy measures and their governance implications. Alternative groupings of the policy measures have been considered but were not pursued due to lack of internal coherence or non-compatibility. Further, several policy measures were included across the policy options as they do not compromise the internal coherence of the options.

Table 1: Specific objectives, policy options and policy measures

Specific objective	Policy measures		PO1	PO2	PO3
A) Infrastructure planning and project implementation					
SO1: Ensure that projects included in network plans address appropriately identified needs	A.1	Strengthening the existing framework	X		
	A.2	Increased EU level steering / coordination		X	
	A.3	Fully centralised approach			X
	A.4	Alignment of scope (smart gas grids/ blending, electrolysers, PMIs)	X	X	X
	A.5	Broadening scope of PCI categories (modernisation and digitalisation)[104]		X	X
B) Cost and benefit sharing					
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	B.1	Enhancing transparency and strengthening EU principles for cross-border energy infrastructure costs and benefits sharing	X	X	X
	B.2	Use of congestion income for financing of cross-border electricity infrastructure as an incentive to cost-sharing	X	X	X
	B.3	Enabling framework for voluntary bundling of projects		X	X
	B.4	Mandatory offshore regional planning and cost-sharing			X

[104] On the broadened scope to better reflect security/resilience within the PCI scope see policy measure D.3

C) Permitting					
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations	C.1	Supporting the implementation of existing legislation and issuing guidance	X	X	X
	C.2	Targeted legislative changes to accelerate permitting		X	X
	C.3	Centralised EU-wide permitting coordination regime for certain large-scale energy infrastructure projects ("28th Regime")			X
D) Security					
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	D.1	Including physical and cyber-risk resilience considerations in the monitoring of PCIs and PMIs	X	X	X
	D.2	Additional transparency requirements regarding the ultimate beneficial owners of candidate PCIs/PMIs		X	X
	D.3	Including security and resilience-related equipment for the upgrade of existing electricity cross-border infrastructure under TEN-E scope		X	X

Policy option 1 entails an **enhanced bottom-up** approach. It introduces only a limited number of changes to the current EU legislative and policy framework in comparison to the business as usual ("BAU") and involves minimal additional EU-level intervention.

Policy option 2 entails **moving from a bottom-up more towards a top-down approach** with stronger steer from the EU level and enhanced coordination with the current actors at Member State level. It introduces more significant changes to the current EU legislative and policy framework as compared to PO1, with additional EU-level coordination and reallocation of certain responsibilities among relevant stakeholders.

Policy option 3 entails a **full top-down** approach for cross-border infrastructure. It includes substantial structural and institutional changes to the *status quo* and a higher degree of centralising and streamlining at EU level, including through entrusting infrastructure planning and coordination of permitting for cross-border infrastructure projects to EU bodies. It also includes a mandatory offshore regional planning and cost-sharing framework.

<u>Stakeholder views</u>:

On **infrastructure planning (Measures A),** a majority (54%; companies 49%, business associations 63%, NGOs 71%, public authorities 40%) indicated that the current governance framework of the TYNDPs, including stakeholder roles, should be revised to enhance its effectiveness. About half (44%; companies 37%, business associations 43%, NGOs 86%, public authorities 50%) believed the TYNDP falls short in addressing identified infrastructure gaps and a majority (60%; companies 53%, business associations 70%, NGOs 100%, public authorities 50%) agreed that national projects should more clearly support EU-wide priorities (in line with PO2 and PO3). A majority of respondents (61%; companies 56%, business associations 61%, NGOs 93%, public authorities 60%) also agreed that there is a need for stronger alignment between national transmission development plans as proposed under PO2. A majority of respondents were positive to the inclusion of internal reinforcements (72%; companies 66%, business associations 78%, NGOs 93%, public authorities 70%) and non-wired solutions (54%;

companies 49%, business associations 63%, NGOs 71%, public authorities 40%) in infrastructure needs identification (all POs). Moreover, a majority of respondents (59%; companies 63%, business associations 57%, NGOs 36%, public authorities 50%) were positive to streamlining the PCI/PMI application process by amending requirements for projects with PCI-PMI status to reapply during each process (provided certain conditions are met). On the frequency of the processes, most stakeholders (85%) found the current two-year cycle appropriate in line with PO1 as reflected in the possible updates in PO2 and PO3.

When asked whether the TYNDP should have a more top-down approach to infrastructure planning more in line with PO2 and PO3, 41% of respondents (companies 41%, business associations 43%, NGOs 14%, public authorities 40%) disagreed whereas 36% agreed indicating mixed views. Note that there is wide variance in responses within the company category. While a strong majority (70%) of TSOs disagreed with the statement, only 19% of project promotors, 29% of energy suppliers, 38% of energy offtakers, and 46% of DSOs disagreed. Similarly, 41% of respondents (companies 42%, business associations 46%, NGOs 7%, public authorities 30%) expressed disagreement with the TYNDP having a more top-down European approach to better link identified needs and priority projects of common European interest (agreement 36%, neutrality 12%, uncertainty 12%). Again, a strong majority (70%) of TSOs and DSOs (62%) disagreed with the statement, while only 19% of project promotors, 24% of energy suppliers, and 38% of energy offtakers disagreed.

As regards the **cost-sharing (Measures B)**, 38%[105] (companies 40%, business associations 37%, NGOs 36%, public authorities 20%) of respondents stated that the current framework is not fit for purpose. Further, 37%[106] (companies 30%, business associations 39%, NGOs 43%, public authorities 30%) of respondents thought that an investment request within the CBCA framework could also cover several projects ('bundling') and 36%[107] (companies 31%, business associations 35%, NGOs 57%, public authorities 30%) favoured that it would develop further to facilitate the sharing of investment costs, in line with PO2 and PO3.

Concerning permitting (Measures C), the OPC indicated a vast majority of stakeholders across respondent categories support the digitalisation of permitting procedures, shortening of legal deadlines for permitting of networks, and establishment of such deadlines where missing – suggesting support for further action than PO1. Views were more mixed on the simplification and streamlining of environmental assessment with a majority of companies (92%), business associations (83%) and public authorities (70%) expressing support, and about a third (29%) of NGOs.

On **security (Measures D),** over a third of stakeholders agreed that the EU legal framework does not sufficiently address emerging security risks (38%; companies 37%, business associations 44%, NGOs 36%, public authorities 40%)[108] and that additional security criteria for PCIs and PMIs are needed to enhance protection against physical and cyber risks (36% companies 33%, business associations 31%, NGOs 29%, public authorities 60%).[109] Furthermore, only 14% indicated that the framework addresses the exclusion of non-trusted actors from participating in

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105 20% of respondents were neutral and 35% expressed no opinion (see Annex 2).
106 25% of respondents were neutral and 32% uncertain (see Annex 2).
107 18% of respondents were neutral and 31% uncertain (see Annex 2).
108 18% of respondents were neutral and 32% uncertain (see Annex 2).
109 14% of respondents were neutral and 27% uncertain (see Annex 2).

critical infrastructure projects, indicating support for further measures in line with PO2 and PO3.[110]

5.3. Options discarded at an early stage

As mentioned in the previous section, alternative groupings of the policy measures on A) infrastructure planning and project implementation, B) cost and benefit sharing, C) permitting, and D) security were considered but discarded due to a lack of internal coherence or non-compatibility of the measures.

6. WHAT ARE THE IMPACTS OF THE POLICY OPTIONS?

This section presents the main expected economic, social and environmental impacts of each policy option[111]. To the extent possible, the impacts are quantified based on available assessments or modelling by the JRC. Considering that all policy options entail changes to governance structures, the impacts of the proposed measures will be linked to the outcomes of their implementation in the longer term. Where modelling was not possible due to the lack of tools or data, qualitative assessment is used building on available studies and input from stakeholders. Additional data are provided in Annex 4.

6.1. Economic impacts

Economic impacts are assessed against their impact on the EU energy system, competitiveness and digitalisation as well as in relation to the administrative and adjustment costs.

6.1.1. Energy system benefits

The economic impacts of the proposed policy options in terms of **reduced energy system costs** can be quantified for the electricity system, whereas this is not possible to a reasonable degree of certainty for the hydrogen sector given the early stage of hydrogen infrastructure development. The assessment builds mainly on ENTSO-E data, complemented by JRC modelling (Annex 4).

The expected impacts of the BAU scenario are estimated under assumption of timely implementation of the TYNDP projects portfolio and need to be adjusted considering expected delays and challenges to project deployment under the BAU. The **implementation of 2024 TYNDP project portfolio by 2040 (211 projects) would lead to the increase of EU GDP by EUR 247 billion by 2040**.[112] The BAU is based on the scenario compliant with the Union energy and climate targets and takes into account to the extent possible future developments of demand and supply indicated in the national energy and climate targets.

The benefits of the proposed policy options are assessed by looking at their potential to achieve the optimal grid where all needs for energy transmission capacity[113] are addressed leading to a cost-effective energy system compliant with the Union energy and climate targets. As it is difficult to assess which investments would materialise, it is assumed that they would lead to partial implementation of the optimal grid and hence achieve partial benefits associated with it.

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[110] ,Almost a majority (45%; companies 41%, business associations 48%, NGOs 86%, public authorities 40%) being uncertain.

[111] The analysis in this section is based on an on-going support study, the analysis of stakeholders' feedback as well as JRC modelling as further explained in Annex 4.

[112] ENTSO-E (2025), TYNDP 2024. Figures for the National Trends + 2030 and 2040 scenarios

[113] ENTSO-E (2025), TYNDP 2024. Opportunities for a more efficient European power system by 2050. Infrastructure Gaps Report.

Partial implementation of the optimal grid would mean lower costs of investments but at the same time higher overall energy system costs (due to redispatch or renewables curtailment) offsetting the savings from lower investment costs. It is thus not possible to associate economic costs of specific options in a meaningful way. Consequently, the benefits and investment costs of each option are assumed to be up to the levels associated with deployment of the optimal grid, without specific levels associated to the options.

PO2 and PO3 would **increase benefits** –to a similar degree– by ensuring that *identified projects better match and fully cover the identified needs (SO1)*, leading to an optimal and resilient grid. PO1 would achieve these benefits only to a limited extent, as it lacks a gap filling mechanism to match project planning and development to identified infrastructure needs.

For 2030, the optimal grid (see Annex 4) could lead to additional EUR 8 bn/year reduction in electricity system costs, which compared with the required additional investment of EUR 5 bn/year would lead to EUR 3 bn/year savings for the EU economy. However, the impact of the proposed measures might be limited until 2030 in view of their expected entry into force. For 2040, investments of EUR 6 bn/year into the optimal grid would lead to EUR 14 bn/year reduction in system costs, that is EUR 8 bn/year net saving (only part of these savings could be achieved by the already planned projects under the BAU scenario, corresponding to 78 GW new capacity to be added by 2040)**Error! Reference source not found.**. **PO2 and PO3**, which include a gap filling mechanism, **would help bridge the gap of 30 GW not covered by any projects**, corresponding to EUR 1.8 bn/year in additional net savings.[114] The actual savings would most likely be higher because the proposed options would also reduce delays and difficulties in implementing planned projects.

Net savings achieved via PO2 and PO3 would benefit consumers, electricity producers and system operators, but the distribution of benefits is not possible to estimate. While higher electricity grid investments could lead to higher network tariffs for all consumers, the overall lower energy system costs would also be transferred to consumers via lower wholesale electricity prices. These impacts depend on the number of electricity consumers and the level of electricity consumption (see Section 6.2 on social impacts). The geographical distribution of impacts will depend on the actual projects.

PO2 and PO3 would have a similar, substantial impact on wholesale electricity prices. Better interconnectivity leads to price convergence and, overall, more stable and lower prices, with some countries facing an increase and others a decrease of prices, ranging from EUR +10/MWh to EUR -10/MWh.[115] Still, the increase of prices should not be considered as a welfare loss since generation surplus and congestion rents related to the new interconnectors should also be taken into account. This is reflected in the overall reduction in energy system costs. Addressing infrastructure needs would lead to a reduction of wholesale electricity prices in several Member States, including the Eastern part of Europe where the problem of high and volatile electricity prices is most prominent.

PO2 and PO3 also bring positive economic impact for RES deployment and integration. Better planning and faster permitting of electricity grids may **help avoid approximately EUR**

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[114] Calculations based on ENTSO-E (2025), TYNDP 2024.

[115] Excluding the possible non-mature interconnectors through the Mediterranean and long HVDC connections spanning multiple countries which are included in the TYNDP2024.

37 billion in annual redispatching costs in 2040, if the grid is expanded accordingly (see Annex 4 for more details).[116]

Deployment of grid enhancing technologies, which would be prioritised in all policy options when identifying possible projects, could **expand network capacity by 20-40% by 2040 and save up to 35% in conventional grid expansion costs.**[117] The deployment of dynamic line rating, one of the well-established grid enhancing technologies, on most congested network elements could **bring net benefits of EUR 2.67 billion**[118] over a period of 20 years through additional 27 GW of available transmission capacity.[119] PO2 and PO3 are expected to create higher benefits from grid enhancing technologies due to broadened scope.

PO2 and PO3 bring greater possibility to account for anticipatory investments, but also long grid development lead times (up to 10 years as mentioned earlier) as they would **prolong national grid planning horizons to at least 15 years.** Underinvesting in grid infrastructure may become costlier to society in the medium term than making anticipatory investments under controlled scrutiny and risk management processes.[120] While estimates are not available for the whole EU, examples indicate the potential benefits. In Austria, anticipatory grid investments of EUR 133 million could prevent costs of EUR 1.5 billion in 2040.[121] Furthermore, the Scottish TSO, for instance, estimates that customers would save up to GBP 750 million over the two and a half years if an equivalent grid capacity at a cost of around GBP 25 million per year was built.[122]

To accommodate the growing demand for renewable and low carbon hydrogen—while ensuring the competitiveness of key European industries—a **substantial expansion of hydrogen infrastructure is required**. In its 2024 Hydrogen Monitoring Report, ACER highlights the need for integrated planning to accurately assess infrastructure needs, prevent overinvestment, and mitigate cost recovery risks. The BAU scenario and PO1 risk fragmented, inefficient development, leading to higher economic costs. In contrast, **PO2 and PO3 promote enhanced cross-sectoral planning,** better adapting infrastructure to evolving supply and demand, thereby ensuring more cost-effective outcomes. While the quantification of potential benefits comes with a high level of uncertainty**, positive impacts of cross-sectoral planning** could bring synergies across energy vectors and efficiency gains across the energy system.[123] Integrated planning of all sectors in Europe could bring as much as **EUR 561 billion savings between 2030-2050**[124], with significant reduction of investment needs. Up to **EUR 200 billion in savings from avoided back-up capacities** could be achieved.[125]

Changes in the assessment rules for PMI candidates with Energy Community Contracting Parties should bring positive benefits from **market coupling and security perspectives**. Better interconnected networks in the synchronous European area can improve integration of renewable energy sources and loads, decreasing the risk of supply disruptions and related socio-economic

[116] European Commission, Joint Research Centre, Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, Redispatch and Congestion Management (2024)
[117] See for instance CurrENT study: Prospects for innovative power grid technologies, 2024, PowerPoint Presentation
[118] Commission analysis of benefits of DLR deployment on 143 most congested CNECs (critical network elements used for capacity calculation in CORE region) based on ACER data (see Annex IV for details)
[119] Total benefits per 20 years: 2,819,948,354 EUR, total costs: 146,783,715 EUR.
[120] Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networks
[121] The economic value of electricity distribution grids on the path towards climate neutrality in Austria (translated)
[122] https://www.ssen-transmission.co.uk/news/news--views/2022/11/the-real-cost-of-having-insufficient-grid/
[123] Bundesministerium für Klimaschutz, Umwelt, Energie, Mobilität, Innovation und Technologie (BMK) (2024) Integrierter österreichischer Netzinfrastrukturplan
[124] Based on preliminary findings on Agora Energiewende Integrated Infrastructure planning PyPSA-Eur model, as presented in 2025 Copenhagen forum
[125] Ibid

costs, including in countries of high geopolitical importance in our neighbourhood, notably Ukraine and Moldova.

Establishing the **cross-border nature of electrolysers** had proven challenging based on the 50MW capacity threshold stipulated in the TEN-E Regulation in force. Electrolysers that applied for PCI status of 50MW capacity were very often not connected to a (planned) hydrogen network, but rather supplied on-site or local consumption – usually industry. While it appears that electrolysers as large as 500MW may also serve on-site demand (as evidenced by the applications and complementary analyses of the European Commission in the PCI/PMI selection process), the likelihood of large-scale electrolysers realizing economies of scale that could feed a hydrogen transmission system and be part of an integrated hydrogen network planning is higher with larger capacities than the relatively modest 50MW size. By focussing TEN-E recognition on large-size electrolysers with cross-border relevance, project promoters can expect to be able to more efficiently distribute fixed costs, realise operational efficiencies and capitalise on their bargaining power especially *vis à vis* technology suppliers in the early stages of market development.

Furthermore, removing incentives for the blending of hydrogen with natural gas, as foreseen in all policy options, would lower system costs since it would ensure a more efficient use of hydrogen while preventing barriers to the internal market. In the impact assessment accompanying the hydrogen and gas decarbonisation package, the Commission estimated that while a 5% allowed hydrogen blending cap at cross-border points would lead to lower emissions (8 Mt CO_2/year of avoided emissions), with an adaptation cost of EUR 3.6 bn/year, a 10% or a 20% cap would increase the adaptation costs drastically (EUR 5.4 bn/year for 10% or EUR 12.5 bn/year for 20%). Importantly, whilst blending of hydrogen in the natural gas network at a limited percentage may enable decentralised renewable hydrogen production in a transitional phase at the level of local networks, the TEN-E Regulation aims at the promotion of investments that have a significant cross-border impact and is therefore neither a suitable nor efficient tool to promote such local networks. The same applies to the integration of biomethane.

As for ***cost and benefit sharing*** *(SO2)*, the BAU scenario would involve substantial welfare losses caused by delayed implementation or non-materialisation of projects due to complex or deadlocked discussions on cost sharing. While a quantitative assessment of direct economic impacts is challenging given that the allocation of benefits per project is not currently disclosed within the TYNDP or the PCI/PMI lists, assessments carried out for offshore developments in the EU's sea-basins provide an indication on the potential impacts both for offshore and onshore.

According to ENTSO-E's[126] cost-benefit sharing assessment of the EU's sea-basins offshore network development plans (ONDPs)[127], the benefits of future hybrid offshore projects are expected to extend beyond the hosting countries. ENTSO-E estimated that **the potential installed capacity of such projects, with benefits beyond host countries** (not yet existing or planned), **amounts to 25 GW by 2040 and 44 GW by 2050**.[128] These assets are expected to incur investment costs of approximately EUR 23 billion, while generating almost EUR 70 billion

[126] ENTSO-E, Sea Basin Cost Benefit and Cost Sharing: final results, 4 July 2025.

[127] TEN-E requires EU Member States to agree on non-binding targets for offshore renewable energy they plan to deploy within each sea basin by 2050. These serve as the foundation for Offshore Network Development Plans (ONDPs), which outline the infrastructure needed to achieve Member States goals. ENTSO-E, based on a Commission Guidance published in June 2023, shall carry out cross-border cost-benefit assessments of those ONDPs to inform Member States and support upcoming planning and cost-sharing discussions at regional level. The first assessment final results were presented to the TEN-E offshore grids corridors members on 4 July 2025.

[128] This includes 21.5 GW in the North Sea, 3 GW in the Baltic Sea and 700 MW in the Atlantic Ocean by 2040. For 2050, it would concern 8.5 GW in the North Sea, 10.6 GW in the Baltic Sea and 700 MW in the Atlantic Ocean.

in socio-economic welfare over their economic lifetime.[129] It can be assumed that all of these projects are unlikely to materialise or only with significant delays in the absence of more effective cost-sharing tools. The resulting economic impacts under a BAU scenario in terms **of the loss of net socio-economic welfare** (SEW) over their lifetime would be at least EUR 20 billion for 2040 and an additional EUR 10 billion for 2050 assuming that 30-50% of the projects would be delayed or not realised (see Table 2).

[129] Socio-economic welfare consists of consumer surplus, producer surplus, congestion income and cross-sectoral rent. Importing countries would tend to see their consumer surplus increase and their producer surplus would decrease, and vice versa for exporting countries; from the prices changes between market zones and across the electricity and the hydrogen system, congestion rents and cross sectoral rents might go up or down.

Table 2: Loss of socio-economic welfare of non-realised hybrid offshore projects

Year	Offshore hybrid capacity needed (GW)	Investment costs (bn EUR)	Assumed % not realised or delayed	Capacity delayed or not realised (GW)	Cumulative loss of SEW if projects are not realised (bn EUR)
2040	25	23	30-50%	7.5 -12.5	20.85- 34.75
2050	44	19	30-50%	13.2 - 22	10.05- 16.75

Source: Own calculations based on ENTSO-E assessment

The measures foreseen in PO1, PO2 and PO3 to facilitate more effective cost-sharing are expected to help realise these potential socio-economic benefits but to different degrees. Enhanced transparency and updated recommendations on the preparation of CBCAs will support cost-sharing agreements. The impact of PO2 and PO3 is expected to be higher as a result of an enabling framework that allows TSOs and Member States to voluntarily bundle projects. This would further facilitate cost sharing as demonstrated in past examples.[130] The framework would provide visibility on possible incentives, such as the PCI status and related CEF funding and could enable the establishment and implementation of a first project bundle in the North Sea and provide inspiration for other offshore and onshore regions. PO3 could lead to higher impacts given it is mandatory although this might weaken a trust-based approach and would be limited to offshore, where projects are already planned, hence likely lead to similar impacts as PO2.

Under all policy options **congestion income is considered** as source for financing of cross-border electricity infrastructure, acting as an incentive to cost-sharing. The account balance for congestion income not used in the previous years and placed in a separate account line amounted to more than EUR 9 billion.[131] This would increase to more than EUR 11.4 billion in 2025 (see Annex 4 for more details). This data indicates that a **substantial portion of congestion income remains available** and could be utilised to facilitate cost-sharing agreements providing an **additional incentive to hosting Member States**. This would be possible without reducing current spending on other priorities, hence would not create additional costs. Socialising a share of the congestion income to finance new cross-border electricity infrastructure projects could reduce the need to increase network tariffs to finance these investments in the hosting countries.

As for ***permitting (SO3)***, under the BAU scenario, permitting procedures face significant delays (Section 2.2.5). Delays in permitting of energy infrastructure represent an impact on total generation cost of at least EUR 450 million/year.[132] The example of the "Garenfeld substation" project (Germany) shows a delay of 2 years may cost over EUR 150 million in redispatch costs, which would otherwise have resulted in a EUR 70 million reduction to consumer bills.[133]

[130] E.g. 2004 TSO Nordel Infrastructure Package with the bundling of five prioritised Nordic grid reinforcements: 1. Fennoskan II (Decided) 2. Great Belt (Decided) 3. Nea - Järpströmmen (Decided) 4. South Link (Decided) 5. Skagerrak IV (Letter of Intent, concessions applied), see Annex 9 for further details.

[131] TSOs' proposal for Use of Congestion Income Methodology in accordance with Article 19(4) of Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

[132] European Commission, Joint Research Centre, Finck, J. R., Miletic, M., Terça, G. *The interconnection needs of the European electricity system: Investigations for 2030 and 2040 using METIS,* European Commission, Petten, 2025, JRC143965

[133] ENTSO-E and Renewable Grids Initiative, Value of timely implementation of "better projects (2019)

PO1 would contribute little to accelerating permitting procedure and addressing high and volatile energy prices, as impacts will be limited to the results achieved under the existing framework. **Through creating a clear framework** with concrete shorter deadlines and simpler procedures for the development of RES projects, grids, storage and recharging stations, **PO2, and to a lesser extent PO3[134], would lead to shorter lead time for projects and thus bring positive economic benefits**. This is supported by the experience with the implementation of binding and optional measures to accelerate permitting as introduced by the Emergency Regulation. Germany has made extensive use of the measures in this Regulation resulting in a substantial acceleration of permitting. In 2024, Germany approved approximately 14-15 GW of additional installed onshore wind capacity[135], which represents an 85% increase compared to the previous year. Faster permitting for recharging stations would provide more planning certainty, reduce costs and hence improve the business case for charging operators and accelerate the roll out of charging infrastructure. By 2040, during peak times, electric vehicles utilising bidirectional charging could supply up to 15–20% of electricity demand, serving as a large virtual power plant[136] and provide system flexibility.

Addressing the delays in project implementation is expected to generate benefits in terms of overall **reduced wholesale electricity prices and increase total welfare**. Comparing the initial planned commissioning dates for on-going cross-border infrastructure projects against the latest information from the project promoters shows an average delay of 4 years, equivalent to a **welfare loss of EUR 6.5 billion until 2030**; delays in permitting alone amount to a welfare loss of at least EUR 515 million per year, when compared to a "no delays" scenario.[137]

While the time required to implement the proposed options may not substantially change the situation for 2030, they are expected to support timely project implementation for 2040 and hence prevent welfare losses of an even higher magnitude given the higher number of projects expected to be implemented. In addition to stricter permitting deadlines, PO2 and PO3 would introduce stricter requirements for project assessment which should reduce delays for projects (also linked to delays of other interlinked projects). By introducing an EU-wide approach, PO3 will further enhance coordination in the permitting of projects with a cross-border dimension and very large-scale renewable energy projects in the EU.

As for ***security (SO4)*****,** the policy options would have varying economic impacts. The additional risk assessments in relation to physical and cybersecurity measures, included in all POs, together with better inclusion of security and resilience-related equipment under PO2 and PO3, would lead to benefits in terms of avoided costs of incidents, such as outages and emergency repairs. For instance, the outage of the Estlink 2 interconnector between Estonia and Finland in 2024 resulted in repair costs of EUR 30 million compared to a loss in socio-economic benefits of EUR 94 million. The second outage in 2025 resulted in total repair costs of EUR 50-60 million.

Including security and resilience-related equipment for the upgrade of existing electricity cross-border infrastructure under TEN-E scope as foreseen under PO2 and PO3, would allow for the

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[134] The reduction in lead times are expected to be delayed for PO3 due to the time needed to create a new EU-level entity and make it operational.
[135] Status of onshore wind energy expansion in Germany (translated)
[136] Fraunhofer study for T&E, Batteries on wheels: the untapped potential of EVs, October 2024
[137] European Commission Joint Research Centre, Finck, J. R., Miletic, M., Terça, G. *The infrastructure needs of the European electricity system: Investigations for 2030 and 2040 using METIS,* European Commission, Petten, 2025, JRC143965

possible financing of part of this equipment via the CEF. This would reduce costs for project promoters and could have a positive impact on consumer bills.

6.1.2. Competitiveness

Impacts on competitiveness are closely linked to economic but also social impacts. An optimal energy infrastructure would result in lower energy system costs (Section 6.1.1). In this regard, all policy options bring positive impacts in terms of avoided cost and hence avoided network tariff increases with the highest impact expected under PO2 and PO3. It is however not possible to further credibly quantify the impact of the measures on competitiveness beyond reduced energy system costs and expected effects on wholesale electricity prices.

Regarding the **impact on manufacturing capacities**, given that most of the supply chain for high-voltage technologies is coming from EU suppliers[138], further increase in grid investments is expected to benefit primarily EU companies. The **completion of the 2024 TYNDP project portfolio** by 2040 (211 projects) with a total CAPEX of 288 bn EUR in the EU would lead to **EUR 603 billion mobilised in production** and create **4.1 million jobs** in the EU.[139]

In general, if Europe can significantly shorten planning and permitting procedures, besides achieving direct economic benefits, its competitive position vis-à-vis direct competitors could also be improved, by **through e.g. cost-efficient electrification of industry.** This concerns for instance connection of data centres or gigafactories, for which grid connection is one of important considerations based on which they decide on their placement.[140]

6.1.3. Digitalisation

All three policy options show positive impact on digitalisation through stronger emphasis on the use of non-wired alternative solutions in grid planning, including in project assessment and filling the identified infrastructure needs. **PO2 and PO3 have higher impact due to better reflection of non-wired alternative solutions in scope of the electricity PCI category**. All non-wired solutions must in practice be encompassed by digital solutions.[141] By this priority treatment of non-wired alternative solutions, all three policy options also **positively contribute to innovation**, by providing clear investment signals for such technologies.

In terms of permitting, **PO2 and PO3 would require Member States to digitalise their permitting procedures**. To do so, permitting authorities would have to integrate digital tools, create and continuously update platforms with relevant data and to upskill their staff to handle the new digital elements. The impact of using such platforms and tools was seen in Portugal and Denmark, where environmental and heritage sensitivity maps that simplify the planning and approval of energy infrastructure facilitated the identification of potential impacts.[142]

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[138] See Communication from the Commission providing updated information to determine the shares of the European Union supply of final products and their main specific components

[139] ENTSO-E (2025), TYNDP 2024

[140] Ember (2025): Grids for data centres

[141] For instance, for dynamic line rating, this would mean installing physical sensors in the grid, but also a digital smart system which automatically evaluates the data and assesses impact on available capacities).

[142] PT: national energy and geology laboratory repository centralising georeferenced information in the energy and geology areas: Laboratório Nacional de Energia e Geologia, GEOPORTAL

DK: Danish Environmental Portal owned by the national government, regions, and municipalities: ARTER

6.1.4. *Administrative and adjustment costs*

PO1 would entail minimal additional administrative and adjustment costs, as limited changes are made to the existing framework. As regards **infrastructure planning**, for PO1 the administrative and adjustment costs are very limited for ACER and the Commission and include one-off costs (to develop framework methodologies) and recurrent costs (verification/monitoring). The one-off costs are comparable to the current situation and the recurrent costs would likely be offset by savings gained through streamlined procedures (e.g. removal of Commission and ACER Opinions which take 3-4 months each). Integrated scenario modelling across sectors is already required under the TEN-E, hence targeted improvements via earlier inclusion of ACER and Commission in the process should not entail significant adjustment costs.

PO1 would also reduce administrative costs for the Commission, NRAs, ACER and Member States by streamlining the hydrogen-related categories under the TEN-E and thereby reducing the number of project applications.

As for **cost sharing**, the requirement for ENTSO-E and ENNOH to publish benefits of TYNDP projects, would involve minimal effort, as this information already exists and would simply be made public. Preliminary, non-binding cost-sharing discussions for mature projects may anticipate part of the workload for concerned stakeholders but would not increase the overall burden and could facilitate more effective coordination later on. ACER would face one-off implementation costs to update its CBCA recommendation (estimated to 1 FTE) and develop a template, and recurrent costs to establish a repository. EU-level CBCA principles would help streamline and harmonise the cost-sharing process, without creating additional burden compared to the BAU scenario. The use of congestion income to finance cross-border infrastructure will introduce new administrative responsibilities, including coordination with other TSOs and relevant NRAs. However, adjustment costs are expected to be very limited since TSOs and NRAs already deal with congestion income and manage the relevant accounts.

As for **permitting,** PO1 would not create new legal requirements, hence no additional adjustment or compliance costs are expected for national authorities. The Commission would support Member States to reduce administrative costs by identifying technical assistance and funding opportunities to support investments in tools, reforms of procedures and trainings needed to increase the capacity of authorities. Moreover, by establishing guidance on the implementation of environmental legislation in connection to permitting procedures, procedural ambiguities would be minimised, reducing authorities' administrative costs.

Concerning **security related measures**, PO1 may incur additional compliance costs. Project promoters who are currently considered as critical entities under the CER Directive, such as TSOs, would experience minimal added burden compared to the *status quo*. For those not currently subject to obligations under the CER Directive or the EU cyber-security framework, additional costs may include specialised expertise to identify, evaluate and mitigate risks related to physical security and cybersecurity. Taking the example of the first PCI/PMI list, this would concern around 8% of project promoters.

PO2 would entail some administrative and adjustment costs, as it involves a more comprehensive revision of the legislative and policy framework. As regards **infrastructure planning**, PO2 would mainly entail **additional administrative costs for the Commission** being responsible for the central scenario development and changes related to the scope of the PCI and PMI process. The former would require additional resources in terms of personnel (18 FTEs) with possible additional costs for external support. At the same time, administrative savings would occur for

ENTSO-E and ENNOH as they would no longer be responsible for the scenario development. Additional administrative costs could be expected for national authorities, TSOs and ACER to ensure data collection and verification for the scenario development as well as for the verification, approval, and follow-up of identified needs. However, they already conduct such tasks under BAU and the reduction of the frequency of TYNDP processes from every 2 years to every 4 years as well as optimisation of the planning process would reduce costs compared to BAU and PO1. The cost impact on ACER can be considered a slight increase.

Regarding infrastructure categories and scope of PCIs/PMIs (all POs), broadening the scope for digital technologies and security upgrades for existing energy infrastructure and lowering the 500 MW cross-border impact threshold for internal electricity lines should attract more candidate projects, hence leading to higher administrative costs for assessing and monitoring the projects. The decrease in number of electrolysers and smart gas grids projects may be offset by increase of projects under the electricity grids category[143], not leading to additional administrative costs.

As regards **cost sharing**, PO2 requires additional resources and administrative responsibilities from stakeholders, especially if TSOs will carry out an extra regional planning exercise. This process would build on existing tools, supported by a specific framework in the TEN-E Regulation and facilitated by the Commission. Member States and the Commission would also need to allocate extra resources to support this process, as well as NRAs who would have to conduct assessments and take decisions. NRAs will be required to get involved in the regulation of projects not situated in their territory and to cooperate with other NRAs and TSOs from several different Member States. As for ACER, the cluster approach should not create additional costs.

On **permitting**, PO2 would introduce new measures requiring implementation by national and local authorities, specifically regarding: equipping permitting authorities with all necessary staff, skills and tools to handle the growing number of permitting requests, the accelerated permitting timelines and simplification of permitting procedures for certain projects and repowering, the creation of digital platforms and tools for the permitting process and for the design of benefit-sharing schemes for public participation in renewable energy projects and new procedures as single points of contacts for electricity transmission and distribution infrastructure in general and storage and recharging stations, not covered by the revised RED. However, this short-term cost effect would translate into savings from a streamlined, simpler and quicker procedures over mid- and long-term.

Security-related measures under PO2 and PO3 are not expected to impose additional costs on project promoters, as the required information regarding ultimate beneficial owners is generally already accessible and will be handled confidentially, thereby minimising risks related to competition or commercial sensitivity.

The most substantial administrative costs are expected for **PO3** and making an EU entity (new or existing) responsible for infrastructure planning and permitting. To estimate the administrative costs of such an EU entity to cover all tasks in relation to **infrastructure planning** (PO3), the current budget of ENTSO-E and ACER can serve as examples (see Annex 4). For the entity, staffing of 50 employees with an annual budget of around EUR 10 to 15 million might be required to carry out all tasks, also considering cost for IT infrastructure. While there might be some offsets due to staff transfers, a substantial part would be in addition to the budget required to

[143] Data allowing to quantify the expected increase in projects is not available. National network development plans do not quantify cross-border impacts of all internal infrastructure. Hence, it is difficult to assess which of existing internal projects could apply for a PCI status.

operate the already existing entities. Since the entity would be independent from TSOs/project promoters, the budget would have to be financed from other sources than membership fees. Whereas some posts of the current entities might be transferred to the new entity, all horizontal functions would have to be established in case of a new entity. However, due to a competence transfer to a new entity, some administrative savings in ENTSOs could be expected.

For **cost and benefit sharing**, the administrative costs are also highest for PO3 on the side of the Commission, Member States, NRAs and system operators, where regional planning and cost-sharing are mandatory for some offshore sea basins where hybrid or cross-border radials are planned. In the short term, this is expected to mainly affect North Sea Member States. Nevertheless, North Sea TSOs, under the OTC, and Member States, under NSEC, have already initiated this process saving some of the necessary resources in the region.

On **permitting**, PO3 would require, in addition to the costs of PO2, the setting up of a coordination entity at the European level. Such a body would be expected to coordinate permitting procedures for at least 250 projects with a cross-border dimension.[144] To do so, it will have to liaise with national and local authorities for authorisation. Taking a conservative assumption in terms of staffing, this authority would require 50 FTEs and an annual budget of around EUR 10 million per year. This administrative cost does not save resources in local administration who would still have to perform the national/local level assessment and implement the decisions on the ground and not preclude the need for reinforcement of the national permitting authorities with additional staff and tools, given that for sovereignty reasons these are still necessary and responsible for the final decisions concerning the projects in question.[145]

6.2. Social Impacts

Grid infrastructure is primarily financed through network tariffs. Therefore, grid investments are reflected in the overall level of network tariffs unless compensatory measures are implemented. Impacts of new grid costs on individual customers will depend on projections for the future energy demand since redistribution of total costs over a larger customer base will reduce network tariffs per unit. This effect is illustrated in Figure 3.[146] On the left-hand side, standard recovery is linked to the situation where assumptions on future grid usage (i.e. volume of loads connected) materialise, in alignment with optimised network planning. On the right-hand side, weak demand means the expected demand (as assumed in the network planning before the investment was made) does not materialise, offtake from electricity grid is lower, and hence fixed CAPEX cost must be spread across a smaller consumer base. A part of the tariff increases could be mitigated by public support such as EU grants and financial instruments or state budget interventions.

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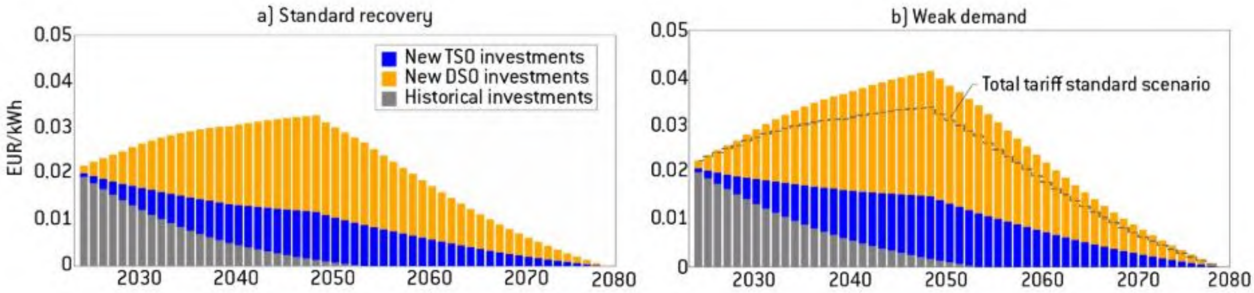
[144] Assuming 220 PCIs and PMIs per Union list and additional cross-border renewable and storage projects.

[145] Under the national law of most Member States (e.g. CZ, MT), different authorisations at the local level will be required despite any coordination at the European level such as: approval of impact on cultural heritage areas, military areas and other urban planning areas; authorisation from the authority responsible for geological and environmental assessments; road and air traffic permits; safety permits; decision on land rights; and construction permits.

[146] Bruegel Heussaff, C., Zachmann, G. (2025): Upgrading Europe's electricity grid is about more than just money

Figure 3: Average grid tariffs for different consumer base



Source: Heussaff/Zachmann (2025)

This indicates that PO2 and PO3 will limit costs on consumers compared to PO1 and BAU, as infrastructure planning under both options is based on the assumption of more precise estimates of future development of demand and supply linked to agreed policies, hence limiting the possibility of future stranded assets and limited use of grid infrastructure. To the extent that PO2 and PO3 will enable further electrification, they will also contribute to an expansion of electricity consumption allowing to spread grid investment costs over a higher number of kWh.

Regarding **cost and benefit sharing**, PO1, PO2 and PO3 would have distributional impacts which are however not possible to quantify for each option. Consumers in Member States with significant consumption needs from electricity imports, are likely to contribute more in terms of network tariffs under all policy options, since these Member States would be the main beneficiaries of such cross-border infrastructure projects. At the same time, they are likely to benefit from higher socio-economic welfare in terms of lower wholesale electricity prices. The exact distributional effects would have to be established for each project or bundle of projects as part of the cost-sharing agreements due to differences in generation and consumption mixes.

Regarding **permitting**, PO1 is not expected to have a substantial social impact, as it will not introduce any change of approach to public engagement. Assets covered under the revised RED, the Gas Directive and the TEN-E Regulation, will experience a perpetuation of the public participation framework leading to no change regarding unease and public opposition towards them. These would be only mitigated by way of ongoing initiatives such as the Pact for Stakeholder Engagement. Further, for electricity transmission and distribution grids, storage assets, and recharging stations in general, impacts are neutral as these assets will not be covered.

PO2 and PO3 entail additional measures strengthening early and effective public engagement and fostering public support for renewable energy projects. The measures expressly include provisions aiming at increasing public participation and therefore social acceptance of renewables projects. By revising the current measures on public acceptance of renewable energy projects, the Commission will be able to assess the opportunity to propose the adoption of measures by the Member Staes that could benefit consumers directly or indirectly, e.g. benefit-sharing schemes and job creation. Indirect financial participation may include measures to promote contracts and job creation for local communities, including training programmes; community benefit funds; financial compensations to local communities in proximity of the project; construction and maintenance of public infrastructure in proximity of the project etc. However, the long-term economic benefits can be limited, as maintenance and operational roles are frequently outsourced to external companies rather than creating jobs for residents. For example, benefit-sharing mechanisms in Australia and South Africa encourage domestic production of components and contractually obligated companies to rely on local workers and permanent local employees. This has supported local creation of construction and operation jobs and fostered the development of skills.[147] This will support the EU's position as a leading job market in the field of renewable energy where it already counts with 1.8 million jobs.[148] The impacts will be the same under PO2 and PO3 as regards benefit-sharing schemes and prospects for local job creation, since PO3 includes alle PO2 measures.

However, the **28th permitting regime** included in PO3 risks significantly deteriorating public acceptance of cross-border projects as they could be perceived as directly imposed by the EU on local communities. Projects subject to this regime, therefore, may risk delays due to court claims linked with public opposition to EU-level decisions.

The social impacts of the **security measures** relate to avoiding increases in energy prices caused by supply disruptions and related repair costs. The additional measures under PO2 and PO3 further reduce risks of possible supply disruptions. Given the lack of available data on the probability of supply disruptions linked to security incidents, the social impact of the policy options cannot be quantified. However, these avoided costs are expected to be substantially higher than the additional costs incurred by each policy options (Section 6.1.1.) that would be passed through to consumers through network tariffs unless covered by other funding.

6.3. Environmental Impacts

GHG emission reductions would bring positive environmental impacts. In line with the climate law, a huge increase of installed RES capacity is required by 2040 to meet the EU's CO_2 emission targets. A recent JRC study[149] shows the correlation between grid development and amount of curtailed energy, where substantial amounts of renewable generation are curtailed due to grid bottlenecks. While some levels of RES curtailment are projected to occur under all future scenarios, ambitious grid expansion would reduce grid related RES curtailment by 40 TWh in 2030 and 110 TWh in 2040 compared to a BAU scenario.

The positive impact of grid expansion on RES integration is also confirmed in the ENTSO-E analysis: the optimal grid would decrease curtailed renewable energy by 143 TWh in 2040 in the EU. The additional 108 GW cross-border capacities needed by 2040 in line with the 2024 TYNDP would also allow to substitute 65 TWh of electricity produced by gas by RES generation, by allowing a better integration of non-CO_2 emitting generation, leading to a significant reduction of European CO_2 emissions estimated at 27 million tonnes of CO_2 emissions avoided in 2040.[150]

Positive environmental impacts are also illustrated by a recent IEA study[151], although with limitations as it covers a broader region than only the EU. The IEA came to the conclusions that cumulative CO_2 emissions from the power sector from 2023 to 2050 would be 58 gigatonnes higher in the Grid Delay Case than in a scenario aligned with national climate targets. This is equivalent to the total global power sector CO_2 emissions from 2018-2022. Specifically for advanced economies, including the EU, the Grid Delay Case results in significantly higher natural gas use beyond 2030, limiting emission reductions in the power sector.

These positive environmental impacts can be mostly expected from measures included in **PO2 and PO3**. By supporting fossil fuels phase-out, PO2 and PO3 would also lead to a reduction of

[147] Ibid
[148] IRENA and ILO (2024), Renewable energy and jobs: Annual review 2024
[149] European Commission JRC (2024): Redispatch and Congestion Management
[150] ENTSO-E TYNDP 2024 Infrastructure gaps report.
[151] IEA report on Electricity Grids and Secure Energy Transitions, November 2023

non-CO2 emissions. While the cumulative impact is difficult to assess, all TYNDP candidate projects lead to a reduction of non-CO2 emissions regardless of the scenario used (see Table 3).

Table 3: Average reduction of non-CO_2 emissions for TYNDP 2024 transmission projects in 2040

Scenario	ΔNOx	ΔNH3	ΔSO2	ΔPM5	ΔPM10	ΔNMVOC
	tonnes / year	tonnes / year	tonnes / year	tonnes / year	tonnes / year	tonnes / year
National Trends+	-149.0	-27.7	-51.9	-3.8	-4.6	-9.8
Distributed energy	-156.1	-24.9	-77.9	-3.7	-5.9	-9.1

Source: ENTSO-E

As regards cost and benefit sharing, taking the previous example of offshore projects in the EU's sea-basin, the implementation of offshore hybrid projects needs which are likely to generate benefits beyond their host countries (25 GW by 2040 and 44 GW by 2050) would result in the following environmental benefits: around 40 TWh of additional RES capacity by 2040 and between 80 and 90 TWh by 2050 resulting in a reduction of more than 4 million tonnes of CO_2 emissions by 2040 and an additional reduction of at least 1.2 million tonnes by 2050. If, as for economic impacts, 30-50% of the projects were delayed or were not to materialise, the resulting environmental impacts would be as follows:

Table 4: Possible non-materialised environmental benefits

Year	Offshore hybrid capacity needed (GW)	RES integration capacity	CO_2 emission reduction (ktonnes of CO_2)	Assumed % not realized or delayed	CO_2 emission reduction not realized or delayed (ktonnes of CO_2)
2040	25	40	4,000	30-50%	1,200 – 2,000
2050	44	80-90	1,200	30-50%	360 - 600

As established above, ensuring the development of energy infrastructures, especially electricity grids, is essential to increase the share of renewable energy generation integrated in the energy mix, preventing environmental losses due to curtailment. RES integration will allow to curb the use of fossil fuels reducing GHG emissions and thus addressing two major drivers of biodiversity loss: climate change and air pollution. The Commission "EU Climate Action Progress Report 2024" mentions that in 2023 alone, there was an 8.3% GHG emissions drop, clearly linked to a strong transition to renewable energy sources, particularly wind and solar, which now supply nearly 45% of EU electricity. [152] Further, according to the IEA, in different model scenarios, renewables sources account for three-quarters of the CO_2 emissions reductions by 2050.[153] Therefore, accelerating permitting procedures for energy infrastructure, storage assets, renewable assets and recharging stations, must be treated as a priority as it will lead to a quicker, and thus larger, reduction of CO_2 emissions by ensuring these key assets are in place as soon as possible.

As regards permitting, PO1 would not produce additional negative impacts on the environment, since it just assists in the implementation of the existing framework, which includes rules related to streamlined environmental assessments under the revised RED. However, as this option does

[152] https://climate.ec.europa.eu/document/download/d0671350-37f2-4bc4-88e8-088d0508fb03_en
[153] IEA (2024) World Energy Outlook, p. 97

not provide a framework for energy networks, storage and recharging stations in general (only for PCIs/PMIs) the benefits of accelerated RES integration are limited. PO2 and PO3 include measures that aim at faster permits and therefore faster and widespread deployment, which relates to more space being used and therefore have an effect on the environment, but they are designed not to decrease the level of environmental protection. Specifically, the proposed measures on digitalisation and centralisation of data required for environmental assessments would improve and speed up administrative processes, freeing administrative capacity in concerned authorities. This, combined with digitalising and centralising environmental data, would enable a more efficient and effective deployment of mitigation and compensation measures as well as facilitate public access to data on all projects, including those not benefiting from the exemptions proposed.

Relevant impacts[154] on the natural and man-made environment, go beyond GHG and non-CO2 emissions. These impacts are strongly dependent on the technology used and the assets' location and the environmental status of the surrounding fauna and flora. Therefore, a general quantification of impacts, or generalisation of impacts per project type, is not possible. These impacts are however addressed in the design of the proposed measures through introducing safeguards. In what concerns potential environmental impacts caused, specifically by granting a presumption of overriding public interest for grids projects, this is rebuttable and on the concerned parties to prove that the negative impacts of the project outweighs the benefits it brings, including towards the needed development of the renewable or infrastructure project. At the same time, the exemptions from any permits are set for only certain types of projects with limited impacts on the environment and the exemption from environmental assessments is always combined with the use of appropriate criteria when setting the new rules that aim to keep impacts at a non-significant level. Therefore, the proposed measures take into account both high environmental standards and the need to accelerate grid and renewable energy deployment to meet our 2030 targets.

The environmental impacts of security measures under PO1, PO2 and PO3 relate to avoiding increases in CO2 and non-CO2 emissions caused by supply disruptions and related repair costs.

The environmental impacts of the measures related to smart gas grids and the blending of hydrogen with natural gas would be positive since any possibility to circumvent the discontinuation of support to fossil fuel infrastructure and to "greenwash" projects would be excluded. At the same time, removing the smart gas grids category would be without prejudice to the contribution that biomethane can bring to decarbonisation at the local and national level, which is the more appropriate level for addressing the grid investment challenge. Indeed, the decentralised production of biomethane in small quantities poses logistical challenges, as locally produced biomethane must be served by only a limited number of injection points.[155]

The primarily national dimension of the biomethane grid challenge is underpinned by the need for Member States to reconcile their varying biomethane potentials and ambitions with Article 57 of the Gas Directive, which provides that Member States must ensure that gas distribution system operators develop network decommissioning plans where a reduction in natural gas demand requiring the decommissioning of natural gas distribution networks is expected.

[154] Collision risks, electrocution risks, soil contamination, disturbance of specific habitats and species or deforestation

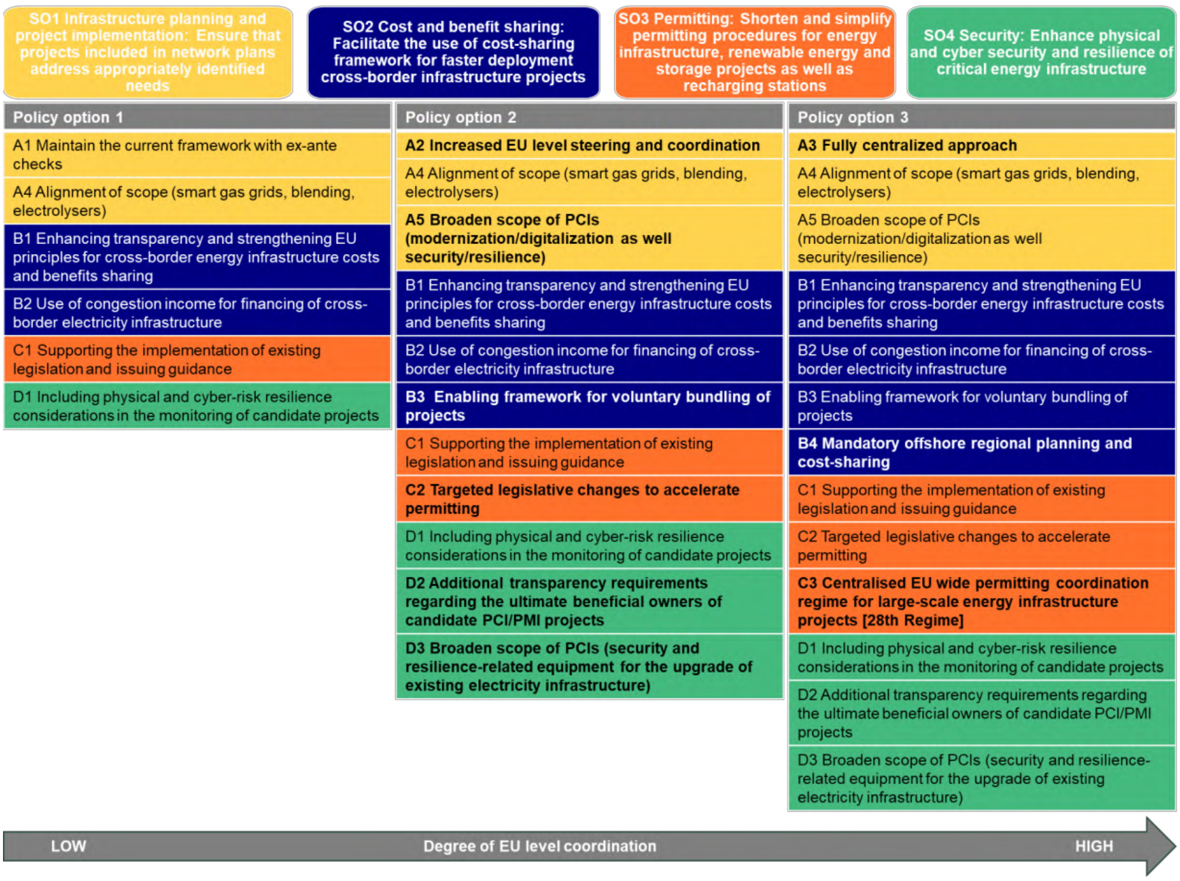
[155] Study on the potential for renewable and low-carbon gas deployment and impact on enabling infrastructure development for the Baltic Sea Region (2025, to be published)

All policy options are consistent with the EU's long-term decarbonisation and environmental objectives and adhere to the do-no-significant-harm principle. They are also assessed to be consistent with the European Climate Law, as they will contribute to accelerating energy system decarbonisation, the reduction of greenhouse gas emissions in line with the Climate Law, albeit to different extents depending on their ability to achieve the optimal grid scenario.

7. HOW DO THE OPTIONS COMPARE?

Figure 4 provides a comparison of the policy options against the specific objectives showing their increased degree of EU-level coordination, PO1 implying a limited number of changes to the status quo and minimal additional EU level intervention, PO2 a more top-down approach, and PO3 involving the highest degree of top-down approach and streamlining at EU level.

Figure 4: Comparison of policy options against specific objectives



In this section the three policy options are compared against the criteria of effectiveness, efficiency, coherence as well as subsidiarity and proportionality, based on the assessment of the impacts in the previous chapter.

7.1. Effectiveness

Effectiveness concerns the extent to which the general and specific objectives (SO) of the intervention (Section 4) are met. Table 5 links the policy objectives to assessment criteria.

Table 5: Links between objectives and assessment criteria

General objectives	Specific objective	Assessment criteria
More rapid and targeted development and interoperability of resilient trans-European energy networks, renewable energy and flexibility, including storage and recharging stations, necessary for leading to lower energy system costs, higher security and lower emissions	Ensure that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs	More robust identification of infrastructure needs
		Clearer link between planned projects/their impacts with the identified needs
		PCIs and PMIs effectively addressing identified needs
	Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	Expected increase in the use of cost-sharing tools
		Acceleration of project implementation
	Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects as well as recharging stations	Shorter time to obtain necessary permits
		Fewer permit requirements
	Enhance physical and cyber security and resilience of cross-border energy infrastructure	Expected reduction in vulnerability risks
		Expected increase in the uptake of security related investments

All policy options contribute to the general objective of timely and efficient development and interoperability of resilient cross-border energy infrastructure, because the proposed measures will improve planning, provide tools to accelerate deployment of priority projects via improved permitting and cost-sharing instruments and enhance resilience of cross-border infrastructure.

Regarding SO1:

- **PO1** would be slightly more effective than the BAU in identifying the infrastructure needs based on ex ante steering through framework methodologies by ACER.
- **PO2 and PO3** would be more effective than PO1 in providing for a more robust identification of infrastructure needs which would be based on a comprehensive central scenario. In addition, the needs identification would have to be approved by the Commission and Member States after ACER and NRAs validated the correct application of the framework guidance. Most importantly, only PO2 and PO3 foresee a new planning element for the systematic follow-up of the identified needs with planned projects through the TYNDP and PCI/PMI selection process (‘gap filling mechanism’). The assessment of the impacts of the different options (Section 6) confirmed that ensuring the implementation of a more optimal cross-border infrastructure grid, as would be the case under PO2 and PO3, would lead to significant economic benefits. PO2 and PO3 would also ensure that non-wired solutions are prioritised and internal lines relevant for cross-border electricity trade are adequately reflected in future grid planning and PCI/PMI selections by adjusting the cross-border criteria.
- The effectiveness of **PO3** might be affected by limited and cumbersome access to data and availability of skilled staff as it would to a large extent depend on sufficient access to data and experience from system operation, which might be delivered late or in a poor quality. Similarly, an entity separate from TSOs responsible for the planning of cross-border infrastructure would weaken the link between the planning of cross-border and internal infrastructure. However, a strong link between these planning processes is essential for effective grid planning. In addition, dissociating the responsibility and liability for the secure operation of the system from network planning, the former remaining with TSOs and the latter placed on a single EU entity, could potentially lead

to inconsistencies, the identification of non-operational solutions and potentially undermine system security, for which specific safeguards would have to be established. In addition, PO3 could entail delays in terms of implementation as establishing fully functioning network models could take between 5-6 years, postponing achievement of the benefits. For these reasons and considering the aforementioned limitations, at this stage PO3 may not meet the SO1 as effectively as PO2.

Regarding SO2, all policy options would enhance transparency in the cost-sharing process by involving a broader range of stakeholders earlier on. The updated ACER recommendation on the treatment of investment requests for PCIs and PMIs would clarify and streamline procedures, promoting a harmonised approach across Member States and projects. Additionally, the introduction of incentives linked to congestion income could motivate stakeholders to engage more actively in cost-sharing negotiations, potentially reducing the overall costs borne by project beneficiaries.

- **PO1** would be more effective than BAU to trigger discussions on cost-sharing but could be insufficient in securing contributions from non-hosting countries, as it relies primarily on improved transparency and clarity. Overall PO1 is considered somewhat effective, but likely not able to reach the SO2.
- **PO2**, by providing a framework coupled with strong incentives for the bundling of projects (joint application for PCI/PMI status and possible CEF funding) and associated cost-sharing process, would ensure a more comprehensive approach to cost-sharing. This approach could overcome the reluctance by Member States to contribute financially to projects outside their territory considering that the cluster will be overall beneficial to them and provide access to the benefits under the TEN-E framework.
- **PO3**, by making mandatory the offshore regional planning would ensure that Member States' offshore commitments are followed up with regional planning and agreements on cost sharing. However, instead of an incentive-based approach (PO2), this mandatory approach could be considered premature and pre-empting Member States' own assessments. Based on past experience with bilateral cost-sharing discussions, mandating multilateral cost-sharing agreements at this stage might face opposition from some Member States and ultimately undermine the actual purpose of strengthening regional cooperation for more effective cost sharing.

Concerning SO3, all policy options include permitting acceleration measures.

- **PO1** would be more effective than the BAU as it would provide further support and guidance to Member States in implementing the current permitting acceleration framework. However, effectiveness is capped to implementation of current framework, which also does not cover permitting of electricity grids and storage infrastructure.
- **PO2** would introduce legislative amendments ensuring shorter permitting times than the BAU and PO1. It would cover cross-border, national transmission and local distribution grids as well as renewable energy, storage and e-mobility charging infrastructure projects. The proposed measures would result in fewer permitting requirements and shortened procedures and thereby address SO2 more effectively.

PO3 is expected to have a similar impact with regard to shortening and simplifying national permitting procedures as PO2, as both options include the same measures in this respect. By introducing a centralised 28th regime for monitoring and coordinating permitting procedures for cross-border grids and large-scale cross-border RES projects, PO3 may facilitate national authorities' interpretation and application of the relevant permitting provisions of EU law. This could result in a more predictable permitting process, preventing situations of preferential treatment and blockage of projects due to national interests. However, PO3 would entail the creation of an additional administrative level to the permitting process, creating further risks of delays in the form of misalignments and of inefficiencies between the EU-level entity and the national authorities. Further, the EU-level entity would lack autonomous competence to decide over permitting procedures (see Section 5.2.1), which raises doubts over the potential coordination benefits. In addition, setting up an EU-level regime to coordinate permitting for cross-border projects would require resources and risks disrupt ongoing permitting procedures and/or delay new ones, though a transitional period could offset this to a certain extent.[156] EU-level permitting monitoring and coordination may also not be welcomed by Member States and other stakeholders, who are mostly calling for targeted changes to the permitting regime to allow sufficient time and resources to implement the existing legislation (see Annex 2). Finally, it risks undermining public acceptance at local level and may therefore result in additional court cases challenging whether national or local circumstances have been adequately taken into account. The overall effectiveness of PO3 as regards permitting is therefore not ensured.

Finally, as regards **SO4**:

- Under **PO1**, the risk assessments reporting would give more prominence to potential physical and cyber-security risks and mitigation measures earlier in the project development cycle
- **PO2 and PO3**, would provide incentives to enhance security of cross-border energy infrastructure under the TEN-E framework and hence would be more effective.

7.2. Efficiency

Efficiency concerns the 'extent to which objectives can be achieved for a given cost (cost effectiveness). The Commission also assessed to what extent the options contribute to administrative and process efficiency (reaching objectives with the least administrative burden). In all policy options, the benefits outweigh the increase in costs, relative to the baseline.

As regards SO1:

- **PO1** would reduce costs by streamlining the planning steps but would still keep the resource intensive 2-year cycle, which would continue to require significant resources.
- **PO2** would be the most cost-efficient option by reducing the frequency of scenarios and needs assessment to 4-year cycles and eliminating some ex-post verification requirements. The new gap filling step would still be less resource intensive than the 2-year cycle. PO2 is also linked to only a limited need of additional resources in terms of staffing.
- **PO3** would be equally efficient with PO2 when it comes to reduction of frequency of scenarios and elimination of ex post verification requirements. While bringing a number of competences under one entity could create operational efficiencies, it would require substantial reshuffling of resources and both high upfront administrative costs for the creation of a new entity or a new section under an existing one (see Annex 9)and additional operational costs to run such an entity. Making an entity operational for these tasks is expected to be very resource intensive and disruptive to the governance of infrastructure planning, possibly offsetting potential gains of a centralised and streamlined approach. It would take several years for such an entity to be fully operational, although this would to a certain extent be addressed with transitional measures.

[156] See the example of other harmonised Union policies where overarching powers have been introduced, e.g. in the case of mergers, the first merger regulation took over 10 years to be negotiated.

Regarding SO2:

- **PO1 and PO2** are both expected to increase the use of cost-sharing tools and facilitate the acceleration of project implementation, where accepted by all relevant stakeholders. Both options offer tools to achieve SO2 at a relatively similar cost compared to the BAU scenario. Several policy measures under these options help reduce the burden on stakeholders by streamlining and enhancing the transparency of the CBCA process. Measures related to congestion income would generate limited additional compliance costs within existing structures. These measures are considered efficient, as the benefits – particularly in financing cross-border infrastructure and encouraging cost-sharing agreements– are expected to outweigh the associated costs.
- **PO2** involves a voluntary process, meaning that any potential additional resources or costs would not be imposed on stakeholders. This would entail significant efficiency gains for Member States and TSOs with a high number of planned hybrid or cross-border radials, since they could bundle projects and simplify cost-sharing frameworks to lower negotiation efforts and, thereby, resources and costs, of conducting multiple and parallel cost-sharing negotiations.
- **PO3** would impose additional costs on all stakeholders as it would require offshore regional planning and cost-sharing agreements. In particular, this would entail costs for Member States and TSOs with a high number of planned hybrid or cross-border radials and hinder the achievement of consensus. In addition, processes would, to a certain extent, overlap with national planning related to cross-border infrastructure, as the approval of investments required at national level.

As for SO3:

- **PO1** is more efficient than the BAU scenario, as it supports implementation of acceleration measures at a low cost. However, its effectiveness is significantly lower than PO2 and PO3, while it represents costs for Member States just slightly lower than PO2. This results from the fact that under PO1 Member States are still expected to invest in administrative capacity building.
- Under **PO2**, costs for Member States increase slightly in the short-term as Member States would be required to introduce and implement legal changes. The costs are, however, likely to significantly decrease in the long-term as a result of digitalisation. Further, the measures on public acceptance and participation, like the benefit-sharing mechanisms for renewable energy projects, will assist in decreasing opposition and lead to less administrative costs in the form of administrative challenges to permits and judicial disputes.
- Under **PO3**, both upfront and recurrent costs increase due to the need to implement further legislative changes and empower with relevant tasks a permanent European coordination entity. PO3 involves continuous operational costs of such EU body that are not required by PO1 and PO2. PO3 might also entail additional costs to support public acceptance and related to an increase in court cases (see above).
- For **both PO2 and PO3**, following the initial investment costs, simplification, better coordination and digitalisation of procedures will decrease the relative administrative burden for national authorities leading to efficiency benefits. In comparison, PO2 appears more efficient than PO1 and PO3.

As for security related measures (**SO4**):

- **PO1** enables earlier consideration of security risks during the initial stages of PCI/PMIs development. While the associated measures may incur additional costs for some project promoters, the number of affected promoters is expected to be limited[157], as most are already subject to comparable obligations under the existing EU regulatory framework. The economic benefits linked to the implementation of identified measures are anticipated to outweigh these costs (see above) and is therefore more efficient than BAU.
- **PO2 and PO3** would be significantly more efficient as they also involve broadening the scope of the TEN-E to reinforce EU cross-border energy infrastructure security, as well as additional oversight concerning possible control by untrusted actors over the projects, without incurring additional costs.

7.3. Coherence

Internal coherence assesses how well the various provisions of the initiative fit together and work in a coordinated manner to achieve its objectives. The measures under each policy option are compatible with each other. However, the effectiveness of some measures may be limited by their co-existence. For PO3, the requirement of mandatory regional planning and cost-sharing are incompatible with the objective of a voluntary enabling framework for project bundling.

As for **external coherence**, all policy options are consistent with EU and national provisions on infrastructure planning and permitting. **PO2 and PO3** would achieve higher coherence by better linking national and EU planning, requiring the use of the central scenario as one of the scenarios as prerequisite for NRA approval of NDPs. The policy options are in line with the EU objective to improve infrastructure planning in the context of the climate transition and complementing other relevant policy initiatives (see Section 1.3). All options would align the TEN-E Regulation with the policy framework on hydrogen as established with the hydrogen and gas decarbonisation package by removing smart gas grids and blending from its scope. PO2 and PO3 would also be most coherent with the Commission's simplification agenda, removing unnecessary provisions related to monitoring and opinions. However, PO3 also brings substantial new administrative implications in terms of setting up new entities or expanding existing ones, and need for related coordination, which may not fully align with the simplification agenda. All policy options are coherent with the existing EU regulatory framework on critical infrastructure protection and cybersecurity, and Foreign Direct Screening Investments. Building on existing provisions and ensuring consistency between regulatory frameworks, they are expected to accelerate implementation of the EU horizontal framework for EU cross-border energy infrastructure.

7.4. Subsidiarity and proportionality

All options fulfil the principle of **subsidiarity**, as they contribute to market integration through better cross-border energy infrastructure and integration of renewable energy sources. This could not be achieved to the same extent with national measures, especially in cases with cross-border dimension. All options preserve the prerogative of Member States to choose their energy mix, level of competence and cross-border energy infrastructure projects. **PO1** provides for the lowest level of intervention but is not sufficiently effective in meeting the initiative's objectives. **PO2** entails a more top-down approach with new responsibilities at EU level while maintaining and strengthening competences at national level and is therefore considered following the subsidiarity principle. **PO3** entails the most intensive intervention through an EU level entity for cross-border infrastructure planning, prescribing regional planning and cost-sharing, and introducing a 28th

[157] Around 8% or 15 project promoters based on the first PCI/PMI list

regime for permitting of cross-border infrastructure projects based on a permanent European permitting coordination authority. This option may therefore be seen by Member States and stakeholders as interfering too much with national processes. A more top-down infrastructure planning approach at EU-level could improve alignment between national and EU-level objectives. However, as described in Section 5.2, approval by Member States is still required in line with the subsidiarity principle enshrined in the TFEU making the close involvement of the relevant national actors, which in any case have the best information regarding national grid characteristics, inevitable. Similarly, as regards a centralised permitting regime coordinated at the European level and implemented by an EU. entity, the EU regime would come on top of national frameworks, requiring the permanent EU Authority to liaise with national and local authorities to verify that the necessary approvals are granted on time, without having direct impact on the national procedures.

As for **proportionality**, **PO1** and to a significantly larger extent **PO2** contribute to improving the more rapid and targeted development of cross-border energy infrastructure, renewable energy, storage and recharging stations effectively, without imposing significant costs for TSOs/project promoters and Member States, NRAs and ACER. **PO3** may raise concerns of disproportionality, due to the involvement of new EU-level entities as regards infrastructure planning and permitting with significant implications both in terms of the costs needed to set-up and operate the new entities as well as the greater top-down EU-level involvement in the network planning and permitting processes.. Creating a new entity or using an existing entity for the purpose of cross-border infrastructure planning may be considered disproportionate in comparison to the expected effectiveness and costs-efficiency of the measure (Sections 7.1 & 7,2)., and considering energy system planning aspects would remain at Member State level due to their responsibility for infrastructure planning and their right of approval as guaranteed under Article 172 TFEU. Mandatory regional planning and CBCAs within EU's sea-basins is considered disproportionate as imposing such binding processes at this stage, possibly undermining trust and overall willingness to engage in such processes. Similarly, the 28th regime for permitting would have considerable limitations in effectiveness as well as cost implications (Sections 7.1 & 7.2), raising concerns over the proportionality of this option. **PO2** would appear more proportional to the nature of the problem by focussing on streamlining the current processes and offering new substantive tools that are considered effective to meet the objectives of this initiative without imposing significant additional costs.

7.5. Summary

Table 6 provides a summary of the comparison of the options against the baseline scenario in terms of effectiveness, efficiency, coherence, subsidiarity and proportionality. The following ranking symbols have been used: from '+' (more effective/efficient/coherent/ proportionate than the baseline) to '+++' (much more effective/efficient/coherent/ proportionate than the baseline); from '-' (less effective/efficient/ coherent/proportionate than the baseline) to '---' (much less effective/efficient/coherent/proportionate than the baseline). See Annex 11 for a detailed comparison. The policy measures under each option do not all carry the same weight in the comparison of each option, as certain measures are expected to have a more significant impact than others on achieving the objectives of the initiative.

Table 6: Comparison of the policy options

Impacts	PO1	PO2	PO3
Effectiveness	+	++	++
Efficiency	+	++/+++	+/++
Coherence	+	++	+

Impacts	PO1	PO2	PO3
Subsidiarity and proportionality	++	+/++	-
Summary comparison of options (contribution to general objective)	+	++	+

8. PREFERRED OPTION

8.1. Identification of preferred policy option

All policy options address the identified problems and their drivers and contribute to achieving the specific and general objectives, although with a different level of effectiveness and efficiency.

From the comparison of the policy options in section 7, PO2 and PO3 are significantly more effective, more efficient and more coherent with the overall EU policy framework than PO1. PO1 only performs slightly better in terms of subsidiarity and proportionality compared to PO2 and PO3. Therefore, PO1 is not considered as possible preferred policy option.

While PO2 and PO3 both perform better than PO1 as concerning their effectiveness in meeting the specific objectives, PO2 seems overall more effective at this stage. when it comes to ensuring that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs as well as to shorten and simplify permitting procedures. As regards the efficiency of PO2 and PO3, PO3 on balance is considered less efficient due to the additional resources needed and high-up front costs coupled with potentially lengthy implementation times to set up two new entities at EU level (or reinforce existing ones) responsible for infrastructure planning and coordinated permitting procedures. In terms of subsidiarity and proportionality, measures proposed in PO3 (EU entities responsible for infrastructure planning and permitting as well as mandatory offshore grid planning) with a high degree of EU level intervention appear disproportionate at this stage considering they do not result in a higher level of effectiveness and are expected to entail substantially higher additional costs.

Without prejudice to political considerations and the final Commission legislative proposal for the European Grids Package, based on the technical assessment presented in this document, PO2 appears as the preferred option. It is expected to enable achievement of the specific objectives to ensure projects included in the network development plans and selected as PCIs/PMIs effectively address identified infrastructure needs in line with the optimal grid scenario, to ensure an increased use of cost-sharing tools and reduced project deployment time for cross-border projects, to ensure a shorten the necessary times to obtain permits and to enhance physical and cyber security resilience of cross-border infrastructure.

The preferred policy option is largely in line with the views expressed by stakeholders in the public consultation (see Section 5.2.2 and Annex 2) including by strengthening tools to address infrastructure gaps, better reflecting internal reinforcements and non-wire solutions in infrastructure needs identification, streamlining PCI/PMI application procedure for mature projects. It strikes a balance between a full top-down approach and a bottom-up approach, thus also taking under consideration the mixed views of stakeholders in this respect. In addition, it addresses shortcomings of the CBCA framework indicated by stakeholders and promotes bundling of projects. The preferred option addresses delays to permitting procedures which was highlighted as a key barrier by stakeholders, through measures such as digitalisation and shortening/setting of deadlines, which received broad support in the consultation. Finally, it includes measures to strengthen the energy-security dimension of the EU's infrastructure framework in line which was highlighted by stakeholders as being insufficient.

8.2. REFIT (simplification and improved efficiency)

The preferred policy option (PO2) brings positive impacts in terms of simplification and improved efficiency. The following measures would reduce compliance and regulatory costs:

- Removal of opinions by ACER and the Commission on draft scenarios and draft infrastructure gaps identification reports as these take in total 6 months and their impact on final deliverable is limited due to late delivery in the process. These 'ex post' measures would be replaced by 'ex ante' measures.
- Removal of ACER opinion on draft PCI/PMI list in particular on the consistent application of the criteria and the cost-benefit analysis across regions. The opinion comes late in the process – after the validation of the draft lists by the technical decision-making body of the regional groups – and hence has very limited impact on the final outcome. Instead, the use of the existing ACER PCI/PMI monitoring and NRA assessment would be strengthened in the PCI/PMI selection process so that these results could be more visible and taken into account in the assessment of candidate projects.
- Simplified application/evaluation process for mature PCIs and PMIs. PCIs and PMIs which have already reached final investment decision or regulatory approval in such a way that the progress of the project is irreversible, or have received a CEF grant for works and show continued progress in their implementation, should retain their PCI/PMI status without the need for reassessment.
- Streamlining the use of priority corridors and Regional Groups to have leaner and more agile approach adapted to changing circumstances.
- Streamlining the CBCA process through enhanced transparency of project specific benefits early in the infrastructure planning process and an updated CBCA Recommendation from ACER will facilitate processes for TSOs and NRAs.
- Shortening permitting deadlines simplifies the process and clarifies the existing framework, reduces the administrative burden on promoters.

8.3. Application of the 'one in, one out' approach

The preferred policy option (PO2) imposes limited additional administrative and adjustment costs on businesses, which would mainly affect TSOs (see Annex 3 and Section 6.1.4). The costs created by the measures under the preferred option (PO2) relate to new security reporting requirements for TSO and project promoters, and a requirement for TSOs to engage in the gap filling mechanism. These costs would either be limited to a small share of TSOs/project promoters or be offset by other measures. Notably, as regards infrastructure planning, the administrative burden on ENTSOs, TSOs and project promoters is expected to be reduced as a result of the Commission taking over central scenario development and simplifications such as the reduced frequency of the TYNDP processes and the simplified application and evaluation process for mature PCIs. The streamlined, simplified and digitalised permitting procedures would also reduce the administrative burden for businesses. The annual costs savings for businesses cannot be fully estimated as relevant data were not available, but it can be concluded that the preferred policy option would lead to recurrent cost saving. In terms of adjustment costs and administrative costs for citizens, the preferred option is not expected to entail any costs. While the costs are limited or non-existent for businesses and citizens, the preferred option would create additional adjustment and administrative costs for the European Commission and ACER, which would take on a greater role in infrastructure planning, and national as well as local authorities for permitting procedures.

9. HOW WILL ACTUAL IMPACTS BE MONITORED AND EVALUATED?

The Commission will monitor and evaluate the impacts of the legislation against a set of indicators allowing to measure progress in achieving the specific. The monitoring builds on a well-established monitoring system under the existing TEN-E framework where ACER and the Regional Groups monitor the progress of projects implementation. Project promoters will continue to submit annual reports to the national competent authorities, which are then subsequently sent to ACER, which consolidates the reports and submits updates to the Regional Groups. This regular reporting provides information on the progress achieved, possible delays and plans to overcome them. These monitoring arrangements are complemented by detailed monitoring by CINEA for PCIs and PMIs that receive grants under CEF.

With regards to permitting measures, the Commission will also rely on the existing channels of interaction with Member States' authorities and relevant stakeholders[158] to monitor implementation of the new measures and potential issues. The effects on renewables generation and integration are also covered by the annual reporting done by Member States. Further, new measures on digitalisation and centralisation of information on permitting procedures will enable an improved management of permit applications by national authorities.

A review of the effectiveness of the new legislation could take place by the end of 2032, when 2 new PCI and PMI selection procedures will have been completed and providing sufficient time for the transposition and implementation of amendments to other legislations in relation to permitting.

The success of the preferred policy option can be measured against operational objectives based on a set of indicators as listed in Annex 8 in particular addressing:

- the extent to which projects included in network developments and selected as PCIs/PMIs address appropriately and effectively identified infrastructure needs;
- the effective use of cost-sharing tools;
- the shortening of permitting procedures;
- the enhanced physical and cyber security and resilience of energy infrastructure.

[158] Platform of National Competent Authorities in charge of the permitting of PCIs and PMIs, permitting expert group, CA-RES, bilateral meetings.

ANNEX 1: PROCEDURAL INFORMATION

1. LEAD DG, DECIDE PLANNING/CWP REFERENCES

The Directorate-General (DG) for Energy was leading the preparation of this initiative and the work on the Impact Assessment in the European Commission. The planning entry was approved in Decide Planning under the reference PLAN/2024/2554. It is not included in the Commission Work Programme 2025.

2. ORGANISATION AND TIMING

The initially planned adoption date (Q1 2026) included in the Clean Industrial Deal and the Affordable Energy Action plan was anticipated to Q4 2025 due to the urgency of the initiative. An inter-service steering group (ISG) was established for preparing this initiative composed of the following Commission services: Secretariat General (SG), CLIMA, GROW, ENEST, REGIO, ENV, JRC, MOVE, HOME, ECFIN, MOVE, TRADE, COMP, SJ. The ISG met 3 times in the period from April until adoption in December 2025.

Table 7: Timeline

Milestones	**Dates**
Publication of the Call for Evidence and Public Consultation	13 May – 5 August 2025
Target stakeholder consultation	May - July 2025
Upstream meeting with Regulatory Scrutiny Board	14 July 2025
Submission to Regulatory Scrutiny Board	27 August 2025
Regulatory Scrutiny Board	24 September 2025
ISC	27 November – 1 December 2025

3. CONSULTATION OF THE RSB

The Impact Assessment report was submitted to the Regulatory Scrutiny Board (RSB) on 27 August 2025. It was presented and discussed with the RSB on 24 September 2025. The RSB gave a positive opinion with reservations on 26The below tables summarise how the revised Impact Assessment report addresses the requested improvements.

RSB requested improvements	**Changes in the revised report:**
(1) The report should clearly present and analyse the problem drivers and clarify to what extent the identified problems are due to implementation flaws in Member States (considering also the lack of data) or due to gaps in the legal framework. It should better explain to what extent this initiative can address the identified problems and how this is linked to other legislation such as the	The text has been revised (section 2) to further clarify the problem drivers and root causes and their links to the proposed measures. It was further explained to what extent the problem relates to issues of implementation of shortcomings in the current legal framework.

Renewable Energy Directive and the TEN-E Regulation.	
(2) The report should analyse the root causes of insufficient investment in grid integration in the EU. It should explain better to what extent the proposed measures can be effective in addressing the need to invest in cross-border grids to respond to new challenges while considering Member State national interests in securing energy supply and providing energy at affordable prices.	The text has been revised (section 2) to better explain the root causes of insufficient investments in grids. In addition, it has been elaborated how the proposed measures and options can help addressing the identified root causes (section 5.3 and Annex 9).
(3) The report should in more detail assess subsidiarity considerations related to a further centralisation of the processes beyond the already existing coordination mechanism under the TEN-E Regulation and explain how this relates to national prerogatives on energy security.	Following the observations from the Board, aspects of subsidiarity have been further assessed in particular in relation to the description of measures under Policy Option 3 (section 5.3) and their comparison against the subsidiarity principle (section 7.4)
(4) The report should clearly define the success in terms of progress towards "optimal grid". The link between the general objective and specific objectives should be better explained. The specific objectives should be defined in S.M.A.R.T. terms to allow for assessing the success and monitoring the progress towards meeting the desired objectives. The report should better describe what data will be used for monitoring and how comparability of data from Member States on permitting procedures including its duration will be ensured.	The general and specific objectives have been revised to make them more specific (section 4) to facilitate their monitoring and assessment based on clear indicators and providing relevant data sources to track progress over time (section 9 and Annex 8)
(5) The report should clearly present and justify how the different options compare in terms of costs and benefits. The "optimal grid" could be also used for comparison of the effectiveness of options.	In the revised version the "optimal grid" and the underlying assumptions were explained in more detail (section 6.1). More detailed assessment has been added with additional data on costs and benefits to the extent available in order to allow for a more granular comparison of the different policy options.
(6) The report should better describe the content of the measures regarding permitting and demonstrate the specific aspects of energy grids also by comparing to initiatives with a view to accelerating permitting procedures in other sectors. The impacts of measures related to simplifying and shortening permitting procedures should be more thoroughly assessed, including an analysis of factors such	Following the Board's observations, the proposed measures on permitting have been expanded to provided additional details on the content and how they compare to other permitting related initiatives (section 5.3 and Annex 9). Furthermore, the expected impacts of the proposed measures compared to the

as national permitting legislation and the duration of court proceedings. For example, it should be explained how imposing shorter deadlines at the EU level may improve the situation given the different circumstances.	baseline have been assessed in more detail (section 6).
(7) The report should highlight possible trade-offs with other EU objectives, in particular linked to the protection of the environment. The environmental impacts beyond greenhouse gas reductions should be thoroughly analysed to allow an assessment of trade-offs stemming from accelerated permitting procedures. The report should describe better any safeguards to address these trade-offs.	The revised text expands on possible trade-offs with other EU objectives, in particular as regards environmental impacts as well as possible safeguards (sections 5.3 and 6.3).

4. EVIDENCE, SOURCES AND QUALITY

The impact assessment draws on evidence from implementation reports, the stakeholder input to the extensive consultations carried out in this respect, as well as from the results of a series of topical studies on key elements of the TEN-E Regulation, which will be presented below.

Formal conclusions adopted in the framework of the Copenhagen Forum in 2023, 2024 and 2025 were also considered in the analysis. The Copenhagen Forum gathers annually representatives of the EU institutions, transmission system operators, project promoters, regulators, energy companies, NGOs and civil society and the financing community to discuss the challenges of developing Europe's energy infrastructure.

ACER's annual consolidated monitoring reports on the progress of electricity and gas PCIs, incremental capacity projects and virtual interconnection points, on the electricity and gas market monitoring and capacity allocation and congestion management, as well as other updates on the cross-border cost allocation decisions, project-specific risk-based incentives were equally considered.

Further information was gathered through several support studies previously commissioned to external contractors to support the development of policy options and assessment on:

Investment needs in infrastructure, infrastructure planning and costs of delays

- European Commission: Directorate-General for Energy, Artelys, LBST, Trinomics, Finesso, A. et al., Investment needs of European energy infrastructure to enable a decarbonised economy – Final report, Publications Office of the European Union, 2025, https://data.europa.eu/doi/10.2833/8232521
- European Commission: Directorate-General for Energy, Fraunhofer, Guidehouse et. al. Study on network development planning, tariff structures and connection requests for electricity distribution grids – Final report, Publications Office of the European Union, 2025,
- European Commission, Joint Research Centre, Thomassen, G., Fuhrmanek, A., Cadenovic, R., Pozo Camara, D. and Vitiello, S., Redispatch and Congestion Management, Publications Office of the European Union, Luxembourg, 2024, https://data.europa.eu/doi/10.2760/853898, JRC137685.

- ENTSO-E: Opportunities for a more efficient European power system by 2050: TYNDP 2024 Infrastructure Gaps Report, 2025, https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/foropinion/Infrastructure_Gaps_Report.pdf

Permitting and delays in projects implementation

- Directorate-General for Energy, Milieu, Bruggeman, V., Vona, L., Moreira, G. et al., Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest under Chapter III of Regulation (EU) 2022/869 – Overview report, Publications Office of the European Union, 2025, https://data.europa.eu/doi/10.2833/2566900
- Technical support for RES policy development and implementation – simplification of permission and administrative procedures for RES installations https://op.europa.eu/en/publication-detail/-/publication/949ddae8-0674-11ee-b12e-01aa75ed71a1

ANNEX 2: STAKEHOLDER CONSULTATION (SYNOPSIS REPORT)

This annex provides a summary of the outcomes of the consultation activities carried out for the preparation of the European Grids Package. In line with the Better Regulation guidelines, the Commission carried out a comprehensive consultation based on a consultation strategy that included a range of consultation methods and tools that combined both backward and forward-looking elements. The strategy was designed in line with the intervention logic.

The consultation strategy aimed to ensure that all relevant evidence were taken into account, including data about costs, societal impact, and the potential benefits of the initiative.

In line with the Better Regulation guidelines, the goal of the stakeholder consultation was:

- To collect views, experience and concrete examples from stakeholders that will illustrate particular opportunities, challenges and impacts resulting from the implementation of the EU legal framework for grids, in particular the TEN-E Regulation, as well as relevant permitting provisions with the view to fill any potential information/data gaps, and facilitate the analysis of the different evaluation criteria;
- To solicit opinions on the extent to which the current legal framework is meeting its objectives.

As a crucial part of the data collection strategy for the evaluation and the forward-looking elements in the impact assessment, a stakeholder mapping exercise has been carried out in order to identify and group the main stakeholders that are involved in and affected by the initiative. The consultation targeted stakeholders inside the EU, both at national and European level. In force since 2022, the current TEN-E Regulation has built an established and well-defined group of stakeholders.

The consultation strategy included a combination of consultation methods (i.e. open/targeted) and tools (including an online public consultation and in-depth interviews) to provide well-reasoned responses and generate the information and evidence necessary to respond to the evaluation questions and inform forward-looking elements in the policy preparation. In particular, an online public consultation was conducted, giving all interested stakeholders and opportunity to submit evidence, provide their views and respond to the structured questionnaire (please see below).

1. RESULTS OF THE OPEN PUBLIC CONSULTATION

An online open public consultation (OPC) was undertaken between 13 May to 5 August 2025 on the ‘Have Your Say’ website. All interested parties were invited to contribute their views on the performance of the TEN-E Regulation, related legal provisions, and areas where further EU action may be needed.

Moreover, the questionnaire for the OPC did not cover all evaluation criteria, but rather non-technical elements on which citizens and the general public can share their views. The consultation covered the following topics: i) the general functioning of the TEN-E Regulation, ii) EU infrastructure planning, iii) electricity network planning at national level, iv) electricity grid hosting capacity, v) permitting, vi) investments in grid infrastructure, vii) supply chains, viii) digitalisation and resilience, and ix) simplification.

The consultation received a total of 197 responses. In addition, 2 emails were received via a functional mailbox for the consultation. There were 197 responses to every multiple-choice question in the OPC, meaning that every respondent answered each question. For some questions, respondents were asked on a five-point scale the extent to which they agreed or disagreed with statements. The scale was i) Strongly disagree ii) Slightly disagree, iii) Neutral, iv) Slightly agree, v) Strongly agree. A "don't know" option was also given. For the purposes of this analysis, responses marked as "strongly agree" and "slightly agree" are grouped under "agree," and similarly, "strongly disagree" and "slightly disagree" are grouped under "disagree".

Table 8 provides an overview of the stakeholder categories participating in the OPC and a brief description of each group's role and relevance to the consultation, ranked according to their respective share of the total consultation responses. The list demonstrates a good coverage of all parties affected by the Regulation. The main category of respondents were companies (90 responses, 45.7% of total), followed by business associations (54 responses, 27.4% of total), NGOs (14 responses, 7.1% of total), EU citizens (12 responses, 6.1% of total), and public authorities (10 responses, 5.1% of total).

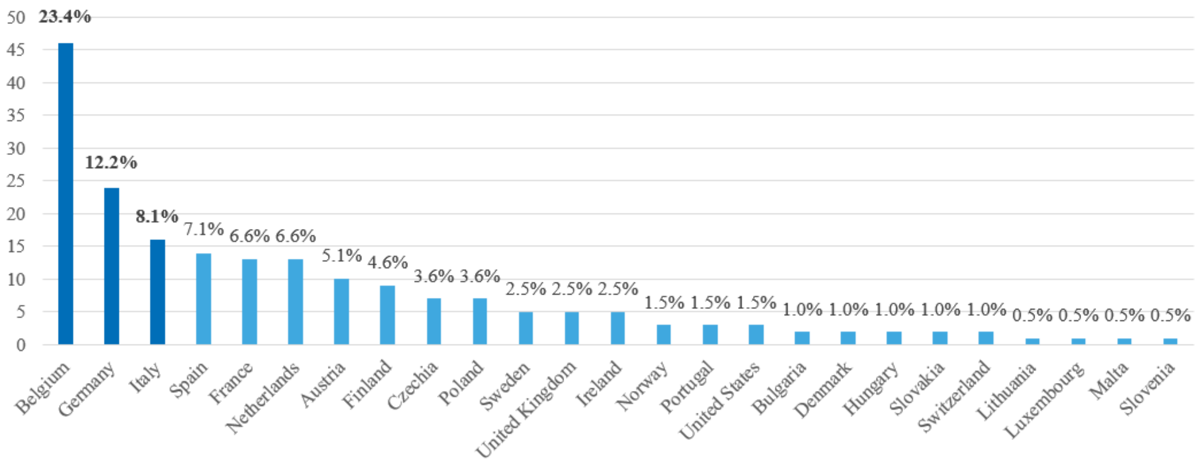
Table 8: Distribution of responses to the consultation by category

Type of Stakeholder	Main Role and Relevance	Number	Percentage
Company/business	Key stakeholders affected by the TEN-E Regulation, especially in energy production, distribution, and infrastructure.	90	45.7%
Business association	Represent interests of industries impacted by TEN-E and provide collective feedback on policy implications.	54	27.4%
Non-governmental organisation (NGO)	Provide perspectives on environmental and social impacts of energy infrastructure projects.	14	7.1%
EU citizen	Direct beneficiaries and contributors to the energy transition; essential for shaping inclusive energy policies.	12	6.1%
Public authority	Responsible for implementing and enforcing TEN-E Regulation at various administrative levels.	10	5.1%
Other	Miscellaneous entities with indirect relevance to the TEN-E Regulation.	8	4.1%
Consumer organisation	Advocate for fair energy prices and transparency in infrastructure projects.	3	1.5%
Environmental organisation	Focus on ecological impacts of energy infrastructure and promote sustainable practices.	3	1.5%
Academic/research institution	Contribute expert knowledge and analysis to evaluate policy scenarios and infrastructure impacts.	1	0.5%
Non-EU citizen	May be indirectly affected by cross-border energy infrastructure and policies.	1	0.5%
Trade union	Represent workers in the energy sector and provide input on labour implications of TEN-E Regulation.	1	0.5%
Grand total		**197**	**100%**

Furthermore, to analyse the responses in more depth, the stakeholder category "Company/ business" was divided into further subcategories. The analysis details the responses of each subcategory of companies/businesses, where a sizable variance can be seen. It should be noted that, when dividing responses into subcategories, desk research on the respective stakeholder as well as professional judgement was used for the disaggregation; this therefore does not represent a classification explicitly provided by the respondents. The subcategories identified and the distribution of respondents are as follows: 27 TSOs, 13 DSOs, 19 Project promoters, 21 Energy generator/suppliers, 8 Energy offtakers, and 2 can be classified as other.[159]

In terms of the distribution of responses to the OPC by country (see Figure 5), most responses were received from Belgium (46 responses, 23.4% of total), followed by Germany (24 responses, 12.2% of total), and Italy (16 responses, 8.1% of total).

Figure 5: Distribution of responses per country



2. FINDINGS

2.1. General questions

When asked to what extent the current EU legal framework for grids delivers on its main objectives (market integration, interconnections, competition/affordable energy prices, energy security), more than half of respondents (53%; companies 56%, business associations 50%, NGOs 43%, public authorities 60%) agreed that it supports market integration, while 12% expressed neutrality and 6% were unsure. Less than half of respondents (40%; companies 41%, business associations 39%, NGOs 14%, public authorities 70%) agreed that it supports interconnections, with 20% expressing neutrality and 8% reporting uncertainty.

Overall, public authorities believe that the framework performs well on interconnections: one public authority mentioned that, for interconnections, there is no reason to expand the legal framework as certain benefits were seen for border connections. Further, another public authority mentioned that the current legal framework has enabled a high level of integration of national

[159] Whereas TSOs and DSOs can relatively easily be identified the other categories leave more room for interpretation. The project promoter category, for instance, includes organisations that develop infrastructure or non-infrastructure (grid) solutions, energy suppliers include organisations that are interpreted to predominantly produce energy and energy offtakers include organisations that are interpreted to predominantly consume energy, such as industrial companies.

markets, which should be seen as a positive outcome, as it has allowed wholesale markets to reach satisfactory levels of liquidity and foster stronger complementarities between markets.

Slightly higher levels of support (45% agreement; companies 49%, business associations 54%, NGOs 14%, public authorities 40%) were observed for energy security, with 15% expressing a neutral stance and 3% being uncertain. Less than a third of respondents (30%; companies 31%, business associations 31%, NGOs 21%, public authorities 50%) agreed that the legal framework supports competitiveness (energy price affordability), while 20% expressed a neutral stance and 3% were unsure.

Regarding key barriers to developing grid infrastructure at the necessary pace for the energy transition, most respondents ranked lengthy permitting as the leading obstacle (78%; companies 83%, business associations 89%, NGOs 57%, public authorities 40%), followed by insufficient financing (59%; companies 61%, business associations 67%, NGOs 36%, public authorities 40%) and regulatory uncertainty (58%; companies 69%, business associations 56%, NGOs 43%, public authorities 40%). Several TSOs and DSOs mentioned that the current permitting procedures for grid infrastructure are too long, leading to significant delays in the overall process. Further comments were made by TSOs about insufficient funding as one of the reasons for major grid delays. One TSO stated that currently TSO face unprecedented investment needs to meet the current demand of the energy transition, and a further TSO argued for the need of improved national regulatory funding models to encourage grid investments.

About a third of respondents, also pointed to additional challenges, including a lack of skilled workforce and poor coordination between grid planning and energy transition needs.

2.2. EU Infrastructure planning

Respondents were asked to assess whether the current framework for the Ten-Year Network Development Plan (TYNDP) and national transmission development plans ensure integrated and coherent planning across EU and national levels. Little more than a third of respondents (37%; companies 44%, business associations 37%, NGOs 7%, public authorities 30%) agreed with the statement, while a similar proportion (34%) disagreed, 14% expressed neutrality and 15% were uncertain.

Views on the extent to which the TYNDP identifies all cross-border infrastructure needs were mixed: 34% (companies 37%, business associations 33%, NGOs 14%, public authorities 20%) agreed, 22% expressed neutrality and 18% were uncertain. In terms of addressing relevant projects to close infrastructure gaps, only 18% said the TYNDP sufficiently captures these needs, while 44% (companies 37%, business associations 43%, NGOs 86%, public authorities 50%) believed it falls short, 22% expressed neutrality and 16% reported uncertainty. When analysing the replies of stakeholders that strongly disagree that the TYNDP sufficiently captures project needs, stakeholders mentioned that a stronger alignment is needed between the TYNDP, national development plans and EU level scenarios. Further, another stakeholder mentioned that the current TYNDP framework is not sufficiently adapted to the realities of more isolated regions, like island regions where systems are not physically interconnected with Mainland Europe. A further criticism mentioned is the absence of views and plans of DSOs DNDP in the TYNDP and the build-up of future scenarios.

When asked whether the TYNDP should have a more top-down European approach to infrastructure planning aimed at aligning network development with EU and Member State climate and energy goals, 41% of respondents (companies 41%, business associations 43%, NGOs 14%, public authorities 40%) expressed disagreement and 36% reported agreement (12% of respondents expressed a neutral stance, 11% did not know). Note that there is wide variance in responses within the company category. While a strong majority (70%) of TSOs disagreed with the statement, only 19% of project promotors, 29% of energy suppliers, 38% of energy offtakers, and 46% of DSOs disagreed.

Similarly, 41% of respondents (companies 42%, business associations 46%, NGOs 7%, public authorities 30%) expressed disagreement with the TYNDP having a more top-down European approach to better link identified needs and priority projects of common European interest (agreement 36%, neutrality 12%, uncertainty 12%). Note that variance in responses within the company category mirrors the previous question. While a strong majority (70%) of TSOs and DSOs (62%) disagreed with the statement, only 19% of project promotors, 24% of energy suppliers, and 38% of energy offtakers disagreed.

Yet, a majority of respondents (60%) (companies 53%, business associations 70%, NGOs 100%, public authorities 50%) agreed that national projects should more clearly support EU-wide priorities (17% was neutral and 13% uncertain). For those respondents who agreed, the argument of serving pan-European interests was mentioned, especially for interconnectors. Further, one TSO mentioned the need for a more top-down European view in identifying cross-border needs, although the implementation of projects should remain at the regional level. Further, several stakeholders mentioned that the TYNDP should adopt a stronger top-down European approach to identify cross-border infrastructure needs and should go beyond the current bottom-up project collection.

When asked which elements should be included in the EU-level needs identification, a large majority of respondents (76%; companies 79%, business associations 76%, NGOs 93%, public authorities 70%) favoured the inclusion of cross-border projects, as well as internal reinforcements required to support those projects (72%; companies 66%, business associations 78%, NGOs 93%, public authorities 70%), and the adoption of a cross-sectoral planning approach (71%; companies 64%, business associations 87%, NGOs 86%, public authorities 50%).

Additionally, 64% of respondents supported the idea of establishing connections with third countries, and 54% supported the inclusion of non-infrastructure solutions such as grid-enhancing technologies.

On whether the current two-year frequency of the system needs identification and scenario-building processes is appropriate, the vast majority, about 85% of respondents, found the current interval suitable; others suggested alternatives, particularly annual simplified updates. Finally, 54% of the respondents (companies 49%, business associations 63%, NGOs 71%, public authorities 40%) indicated that the governance framework of the TYNDP, including stakeholder roles, should be revised to enhance its effectiveness. Note there is a wide variance in responses within the company category. A strong majority (70%) of TSOs disagreed with the statement, followed by 50% of project promotors, energy offtakers and others and only 31% of DSOs and 38% of energy suppliers.

2.3. Electricity network planning at national level

Half of respondents (companies 61%, business associations 46%, NGOs 14%, public authorities 50%) considered the current legal framework for transmission network planning fit for purpose. Note there is a wide variance in responses within the company category. Whereas a vast majority of TSOs (85%), DSOs (62%), energy suppliers (76%) and 50% of energy offtakers and other companies agreed with the statement, 84% of project promoters disagreed. Furthermore, a majority, 61% (companies 56%, business associations 61%, NGOs 93%, public authorities 60%) highlighted the need for stronger alignment between Member States in national transmission development plans. In the company category, 78% of TSOs and 54% of DSOs stated that they consider there to be sufficient alignment, whereas 52% of energy suppliers, 88% of energy offtakers and nearly all (95%) project promotors expressed disagreement with the statement.

A larger majority, 73% (companies 69%, business associations 76%, NGOs 93%, public authorities 60%) supported the idea of a need for better alignment between national transmission and distribution network development plans across the EU. From the company category, a strong majority of project promotors (95%), DSOs (77%), energy offtakers (75%) and energy suppliers (67%) expressed this need, against only 48% of TSOs. Among the reasons mentioned were increased transparency and that DSOs should be part of the scenario-building process in the TYNDPs. One respondent stated that there is currently insufficient linkage between national and cross-border plans and that national development plans currently support national needs, but are not necessarily linked to identifying that support optimum cross-border growth.

Among the elements identified for improvement, common scenarios were the top choice, though still supported by little less than half of respondents (48%; companies 44%, business associations 50%, NGOs 86%, public authorities 40%), followed by alignment of planning scope and outlook period (43%).

Concerning the national distribution network development plans, 34% of respondents agreed that the existing legal framework is not fit for purpose (companies 24%, business associations 44%, NGOs 50%, public authorities 50%), while 16% were neutral and 23% expressed uncertainty. Regarding whether the coverage of small DSOs is sufficient, 30% of respondents were uncertain (companies 39%, business associations 30%, NGOs 21%, public authorities 20%), 30% disagreed, and 21% were neutral. On whether there is sufficient transparency of distribution network development plans, 37% disagreed (companies 28%, business associations 39%, NGOs 71%, public authorities 30%), with 17% neutral and 20% uncertain. Similarly, 37% of respondents found the implementation of these plans insufficient and that their objectives are not met (companies 26%, business associations 37%, NGOs 64%, public authorities 70%), while 17% were neutral and 24% uncertain.

Respondents mentioned the plans lack standardisation and could benefit from a more holistic approach, with better coordination when implementing the plans. It was mentioned that DSOs across the EU can benefit from sharing the DNDPs through a common EU repository to enhance cooperation and share best practices. When asked whether distribution grid operators have sufficient capacity to properly plan distribution grids, 27% expressed uncertainty (companies 34%, business associations 30%, NGOs 29%, public authorities 10%), 27% disagreed, and 21% were neutral. Finally, 29% agreed that stronger coordination of distribution network planning is needed at the EU level (companies 23%, business associations 33%, NGOs 64%, public authorities 30%), with 20% neutral and 24% uncertain.

2.4. Permitting

About a third of respondents (34%; companies 36%, business associations 37%, NGOs 14%, public authorities 10%) reported that the permitting provisions of the TEN-E regulation are not clear and easy to implement, with 16% remaining neutral and 34% unsure. A vast majority of 83% (companies 92%, business associations 83%, NGOs 29%, public authorities 70%) supported simplifying and streamlining environmental assessments (only 5% neutral and 5% uncertain). Similarly, 82% of respondents (companies 83%, business associations 81%, NGOs 79%, public authorities 80%) agreed that permitting procedures should be fully digitalised (only 7% neutral and 9% uncertain). Additionally, 77% of respondents (companies 78%, business associations 85%, NGOs 50%, public authorities 70%) agreed that deadlines for the permitting of networks should be shortened or established where missing, with only 7% neutral and 9% uncertain.

Moreover, 64% of respondents agreed that permitting procedures for storage assets should be simplified (companies 59%, business associations 81%, NGOs 50%, public authorities 70%), with 13% remaining neutral and 18% uncertain. Slightly more (69%) supported simplifying permitting procedures for distribution network projects, small-scale renewable projects, and activities such as repurposing, refurbishment, and repowering (companies 67%, business associations 80%, NGOs 50%, public authorities 60%), while 8% were neutral and 19% uncertain. Furthermore, 71% agreed that permitting procedures for hybrid projects (those combining different technologies, including storage) and other innovative solutions should be simplified (companies 72%, business associations 85%, NGOs 43%, public authorities 60%), with 11% neutral and 14% uncertain.

2.5. Facilitating investments in grid infrastructure

As regards the functioning of the cross-border cost-allocation (CBCA) framework under the TEN-E Regulation, 38% of the participants (companies 40%, business associations 37%, NGOs 36%, public authorities 20%) stated that the framework is not fit for purpose, while 20% of respondents remained neutral and 35% expressed no opinion. Participants cited CBCA's complexity, lack of transparency, and failure to incentivise cooperation among non-hosting countries. They also highlighted the need for alternative financing mechanisms, clearer cost-sharing models, and stronger political commitment to support cross-border infrastructure investments.

In total, 37% of respondents (companies 30%, business associations 39%, NGOs 43%, public authorities 30%) thought that an investment request within the CBCA framework could also cover several projects ('bundling') to facilitate cost sharing amongst more Member State beneficiaries – importantly, 25% were neutral and 32% uncertain. Similarly, 36% (companies 31%, business associations 35%, NGOs 57%, public authorities 30%) favoured that the CBCA framework further develops to facilitate the sharing of investment costs among countries, beyond hosting Member States, in proportion to the expected benefits – importantly, 18% were neutral and 31% uncertain.

On the role of involved actors (Member States, NRAs, ACER, TSOs), 34% (companies 33%, business associations 33%, NGOs 43%, public authorities 20%) supported revising their responsibilities to improve the process, while 22% expressed neutrality and 32% uncertainty. When asked about other instruments beyond CBCA that should be considered or modified to facilitate financing of cross-border infrastructure, 20% (companies 18%, business associations 20%, NGOs 21%, public authorities 40%) favoured sharing congestion income, 18% agreed with the Inter-Transmission System Operator Compensation (ITC) mechanism, 17% preferred a common/regional RAB, and 8% endorsed ex post conditionalities.

Regulatory risk (70%; companies 79%, business associations 67%, NGOs 57%, public authorities 30% - only 8% expressed neutrality and 14% uncertainty) and access to public funding (70%; companies 76%, business associations 70%, NGOs 64%, public authorities 40% - only 11% expressed neutrality and 13% uncertainty) were identified as the most significant financial obstacles to infrastructure investment, followed by access to equity (55%), access to debt (53%), and access to counter-guarantees (44%). Respondents pointed out that the current regulatory and financial environment is generally covers the needs, but required investments for the energy transition increase uncertainty, particularly in the development of hydrogen infrastructure. Respondents also proposed improving grid digitalisation, streamlining permitting procedures, and enhancing coordination between stakeholders to reduce investment risks. They emphasised the need for regulatory clarity, political commitment, and better planning to attract private capital and support long-term infrastructure development.

2.6. Supply chains

Supply chain constraints and shortages in skilled labour appeared to remain key obstacles to grid development. When asked whether current EU and national network development plans offer sufficient visibility for supply chain investment planning, more than a third of respondents (37%; companies 39%, business associations 37%, NGOs 50%, public authorities 10%) disagreed, with 23% remaining neutral and 15% uncertain. Additionally, half of the respondents (51%; companies

57%, business associations 56%, NGOs 57%, public authorities 20%) agreed that there is a need for better visibility to ensure sufficient investment in the supply chains, with 20% remaining neutral and 16% abstaining.

Regarding the need for harmonisation of equipment requirements across the EU, a similar fraction of respondents (52%; companies 52%, business associations 44%, NGOs 50%, public authorities 50%) agreed that this idea would help scale up production and repair capacities, while 19% were neutral and 17% uncertain. Moreover, 66% of respondents (companies 71%, business associations 67%, NGOs 36%, public authorities 20%) agreed that further EU-level action is needed to address supply chain bottlenecks, while 12% were neutral and 14% uncertain. A slightly lower fraction though still a majority of respondents (60%) (companies 56%, business associations 74%, NGOs 43%, public authorities 40%) agreed on the need for additional EU action in the field of skills for the energy sector, following recent initiatives such as the Union of Skills, while 18% were neutral and 16% uncertain.

2.7. Digitalisation and resilience

On whether more EU-level action is needed to enhance the visibility and quantified benefits of digital, innovative, and grid-enhancing technologies, 62% of respondents (companies 56%, business associations 67%, NGOs 79%, public authorities 50%) agreed, with 14% reporting neutrality and 8% uncertainty. A larger majority, 76% (companies 71%, business associations 78%, NGOs 86%, public authorities 90%) argued that further measures are needed to increase the efficiency of the existing grid.

With respect to flexibility planning, about a third of participants (31%; companies 33%, business associations 31%, NGOs 14%, public authorities 20%) agreed that the current regulatory framework sufficiently integrates flexibility needs into network planning and development, with 16% showing neutrality and 8% uncertainty.

On the topic of security and resilience, 38% of respondents (companies 37%, business associations 44%, NGOs 36%, public authorities 40%) advocated that the EU legal framework, beyond the TEN-E Regulation, does not sufficiently address emerging risks such as climate change impacts; however, 18% of respondents were neutral and 32% uncertain. Moreover, 36% (companies 33%, business associations 31%, NGOs 29%, public authorities 60%) agreed that extra security criteria for PCIs and PMIs to enhance protection against physical and cyber risks are needed, with 14% indicating neutrality and 27% uncertainty. Furthermore, only 14% indicated that the framework addresses the exclusion of non-trusted actors from participating in critical infrastructure projects, with 19% revealing neutrality and almost a majority, 45% (companies 41%, business associations 48%, NGOs 86%, public authorities 40%) being uncertain.

2.8. Simplification

When asked about simplifying the PCI/PMI selection process, 42% of respondents (companies 50%, business associations 28%, NGOs 29%, public authorities 30%) opposed the idea of reducing the current frequency of the selection process (every two years), for example to every three years, with 17% remaining neutral and 28% uncertain. A majority of 59% (companies 63%, business associations 57%, NGOs 36%, public authorities 50% - 12% neutral and 25% uncertain) agreed that projects with PCI/PMI status should not be required to reapply for each PCI/PMI process, provided certain conditions are met, and also advocated that the application process should be further simplified (companies 63%, business associations 61%, NGOs 21%, public authorities 40% - 12% neutral and 24% uncertain).

Within the company subcategory, opinions vary significantly. 93% of the TSOs, 67% of the energy suppliers and 50% of the energy offtakers agree that projects with PCI/PMI status should not be required to reapply for each selection process. In contrast, only 46% of DSOs and 31% of the project promoters support this exemption.

Some stakeholders advocated for other ways to simplify the PCI/PMI process and to reduce its length, for example by adopting a lighter approach to maintaining its PCI status for reapplication. Further suggestions to improve the PCI/PMI status mentioned for the application to be reviewed only on a limited number of occasions and questioned only in case of major discrepancies between the situation when it was awarded and the latest set of scenarios. One stakeholder mentioned that this would help avoid diverting scarce resources from project promoters and decrease the uncertainty they face when preparing their project financing.

A similar pattern is observed for the simplification of the application process. Support is the highest among TSOs (74%), energy generators (76%), DSOs (54%), and energy offtakers (50%), while only 44% of the project promoters agree with simplification of the application process.

Regarding additional simplification measures, 45% (companies 50%, business associations 46%, NGOs 14%, public authorities 30%) agreed on simplification in PCI/PMI project monitoring and reporting,[160] followed by 38% supporting simplification in the TYNDP process, and 31% favouring simplification in the offshore network development planning process. One stakeholder mentioned that the PCI/PMI project monitoring and reporting should be harmonised by bundling data collection activities and submission to a single platform. Another stakeholder mentioned that scenario building can be made more dynamic, infrastructure gap identification more transparent and data-driven, and project assessment more streamlined. Offshore planning can benefit from a more integrated and simplified approach to accelerate deployment.

Looking more closely at the company subcategories, support for simplification in PCI/PMI project monitoring and reporting was highest among TSOs (89%) and energy suppliers (52%). Only 15% of DSOs and 31% of project promotors support this measure.

In the TYNDP process, support for simplification varied across the components:

- Infrastructure gap identification: The highest levels of support came from TSOs (59%), and energy suppliers (43%). Moderate support was observed among energy offtakers (38%), while project promoters (19%) and DSOs (8%) showed the lowest levels of agreement.
- Scenario building: Again, TSOs (70%) expressed the strongest support. This was followed by energy generators (38%) energy offtakers (25%), and DSOs (23%). Support among Project Promoters remained low at 19%.
- Project assessment: The majority of TSOs (59%) agreed to simplification efforts. Only 38% of energy suppliers agreed, while project promoters (25%), DSOs (15%), and Energy Offtakers (13%) expressed even fewer agreement.

In the area of offshore network development planning, the company subcategories' views were mixed, with a notable degree of uncertainty. 37% of all company/business type respondents selected "Don't know", with this figure rising sharply to 77% among DSOs, indicating a lack of clarity or familiarity with the topic. Among those expressing a clear opinion, TSOs showed the highest level of support for simplification, with 44%. This was followed by Energy Offtakers (38%), Energy Generators/Suppliers (34%), and Project Promoters (22%).

[160] Importantly, 21% of respondents were neutral and 31% uncertain on this.

ANNEX 3: WHO IS AFFECTED AND HOW?

1. PRACTICAL IMPLICATIONS OF THE INITIATIVE

Summary of the implementation of the preferred policy option

The primary objective of the initiative is to improve the energy infrastructure planning framework so that it fosters deployment of the most effective and efficient solutions. It will also help speed up deployment of priority infrastructure, improve its climate resilience and security. The improved robustness and coordination of scenario building and needs identification at EU level will support infrastructure planning at national level by TSOs and NRAs.

The following key target groups have been identified for this initiative:

- European citizens and consumers
- Project promoters, including Transmission System Operators
- European TSO associations (ENTSO-E, ENTSO-G, and ENNOH)
- National Competent Authorities and their local and regional representatives (i.e. Ministries and outermost regions)
- National Regulatory Authorities
- European Union Regulators
- Distribution system operators and DSO branch organisations (including EU DSO entity)
- Energy producers / Industry
- Charging point operators

The below table outlines the practical implications of the initiative for all key target groups identified

Table 9: Implications of initiative for key target groups identified

Type of stakeholder per target group	Practical implications
European citizens and consumers	Ensuring more fit for purpose energy infrastructure planning will benefit citizens in several ways. Optimal and efficient deployment of infrastructure and renewable energy assets will support phase-out of fossil fuels and lower greenhouse gas emissions. Considering that grid expansion is a prerequisite for the energy transition and for further electrification of the economy, high investment costs in energy infrastructure are unavoidable. These will also affect the tariffs covering the increased costs of infrastructure. The Grids Package will help reduce the costs of investments, by improving planning and identification of key infrastructure priorities and supporting deployment of less costly non-wired solutions. Accelerated permitting process will also allow for a faster implementation of key project, bringing forward the benefits

	identified in cost-benefit analyses at national and regional level and avoiding high dispatch costs for consumers associated with delays. By addressing the security concerns and improving climate resilience of infrastructure, the Grids Package will reduce the risk of black-outs and potential crisis situations caused by power shortage, e.g. transport disruptions. More top-down steering of infrastructure planning will further increase transparency in scenarios and needs identification used for the selection and implementation of PCIs and PMIs, which will help citizens and consumers understand the benefits and necessity for priority projects and hence improve public acceptance. More visibility and predictability of planned infrastructure as well as expansion of investments will have a positive impact on energy sector employment.
Project promoters, including Transmission System Operators	The overall effect on TSOs should be neutral. TSOs will have some additional responsibilities, including to propose solutions to possible unaddressed infrastructure gaps and assess and report security vulnerability for the proposed projects. However, stronger support and push towards non-wired solutions will reduce the pressure on TSOs to pursue all infrastructure projects. Improved coordination with national plans and less stringent requirements for internal lines to qualify for the PCI status will help TSOs deliver key national infrastructure. Also, the European Commission taking over responsibility for scenario building should free personal capacity on TSO side, as TSOs are closely involved in the TYNDP currently next to ENTSOs. Moreover, thanks to reduced reporting and streamlining of the PCI/PMI process fewer resources will be needed to propose and keep projects in the Union list. More robust and predictable long-term planning will create more certainty for investors, allowing project promoters to obtain financing from the market. The streamlining and acceleration of permitting will also lead to reduced costs, faster project deployment, and improved certainty.
European TSO (ENTSO-E, ENTSO-G, and ENNOH)	The main impact on European TSOs will come from the lower frequency of scenarios and needs assessment which up to now are under their responsibility. The lower frequency will help reduce resource needs and ensure timely completion of other TYNDP deliverables. Taking over scenario developments by

	the European Commission will also bring additional savings to these organisations. They will continue to be key actors in infrastructure planning but with less power and discretion on the approach to be taken given the more prescriptive framework and ex ante steering. The more defined rules will reduce the efforts needed to reach agreement between the three organisations on various aspects of the planning which under the current framework was often both time and resource consuming.
National Competent Authorities and their local and regional representatives (i.e. Ministries and outermost regions)	The initiative will increase the involvement of Member States in the infrastructure needs identification process as well as identification of possible solutions. Consequently, additional resources might need to be mobilised in the national authorities to actively contribute to the process. However, this would also give Ministries more influence on the outcomes on the process and should ultimately lead to greater political and public acceptance of grid planning and respective projects. National Competent Authorities (NCAs) would be faced with tighter permitting deadlines but also streamlined and more simplified requirements for grids. They would also need to dedicate resources to the digitalisation of permitting procedures, which are expected to lead to efficiency gains in a longer-term perspective.
National Regulatory Authorities	The role of the NRAs will increase as they will be more involved in the validation of the identified infrastructure gaps as well as the solutions to fill the unaddressed needs. NRAs would also need to better verify the application of the central scenario developed by the Commission meaning that some more thorough scrutiny of the NDPs will be needed, but it is not expected to create much additional work. As regards CBCA, NRAs would have a new responsibility to prepare coordinated CBCAs for the bundle of projects, but the number of such project bundles is not expected to be very high.
European Union Regulators (ACER)	ACER will have a strengthened role in setting a framework methodology for the identification of infrastructure needs. It will also validate the application of the methodology to ensure that the needs are well captured. Monitoring exercise should be merged with the processes under PCI/PMI assessment, which would positively impact ACER from an administrative perspective, but also bring ACER and NRA views earlier in the assessment process. On the other hand, the formal role of ACER will be more prominent in scenario development, as this task will be taken over by the Commission. In addition, ACER

	would have to update the CBCA Recommendation based on principles include in the TEN-E framework.
Distribution system operators	There are no legal changes directly impacting the role of DSOs or bringing further responsibilities. However, continuation of ongoing initiatives and their strengthening (on smart and digital technologies, use of common scenarios and better coordination with TSOs as required by applicable legal framework) will lead to increased role of DSOs.
Energy producers / Industry	The initiative would bring significant positive benefits for energy producers as well as energy consuming industry, as it aims to improve alignment of grid planning with the expected pace of energy generation deployment and consumption. This would allow for earlier grid connection both on the consumption and generation side, and hence positive micro and macro-economic benefits stemming from higher SEW coming from electricity generation (or avoided cost when waiting for delayed grid connection). Better incorporation of the non-wired solutions and grid enhancing technologies would further support the market expansion of these technologies. Streamlined and accelerated permitting procedures for renewable energy projects would improve investment certainty, facilitate quicker project realisation and return on investment for renewable energy producers. The initiative aims to significantly lower energy system costs with positive implications for consumers, including industry. While higher electricity grid investments could lead to higher tariffs for all consumers, the overall lower energy system costs would also be transferred on to consumers, including industry, via lower wholesale electricity prices. By addressing security concerns and improving climate resilience of infrastructure, the Grids Package will also contribute to ensure more reliable energy supply, which is crucial also for industrial consumers.

2. SUMMARY OF COSTS AND BENEFITS

The assessment of **benefits** distinguishes between direct and indirect benefits of the preferred policy option (policy option 2).

Direct benefits of the preferred option are mainly related to reduction of energy system costs due to improved infrastructure planning, reduced CO2 emissions from optimal grid functioning, reduced re-dispatching of renewable energy sources and increased renewable energy integration.

Indirect benefits include overall reduced electricity price, increased competitiveness for European businesses and industry, improved electrification and grid access for transport, industry and data centres and greater energy system security.

Costs and benefits should usually be based on market price (reflecting the opportunity cost of action). However, these are not always available and so other methods may be needed to express impacts in monetary terms or indeed sometimes the impacts cannot be expressed in monetary terms.

The below table summarises the direct and indirect benefits for the preferred policy option based on best available data.

I. Overview of Benefits (total for all provisions) – Preferred Option		
Description	***Amount***	***Comments***
	Direct benefits	
Economic impacts	14 billion n EUR /year of reduction of system costs (composed of total network investment (including costs of related necessary internal reinforcements and generation costs) until 2040	Benefits coming from with the optimal grid meaning the TYNDP projects and addressing all the identified needs associated with yearly investment of EUR 6 bn/year between 2025 and 2040. The preferred option would help to achieve those benefits, but the exact share is hard to quantify.
Reduced CO2 emissions	27 Mton per year in the EU	As above, benefits coming from the optimal grid.
Reduced redispatching of RES	37 billion EUR/year in 2040	Benefits of avoided redispatching in case of relevant grid buildout
RES integration	Avoiding curtailment of 143 TWh in 2040	As above, benefits coming from the optimal grid as well as accelerated permitting procedures for grids, renewable energy generation and storage projects as well as recharging stations.
	Indirect benefits	
Electricity prices	Reduced tariff increases and retail prices	Non-wired solutions and planning based on credible demand projections would lower CAPEX needed to be recovered in tariffs. Better planning allows better and faster RES integration bringing lower prices.
Increased competitiveness	Support for electrification of energy intensive industries EUR 603 billion in mobilised investments into grid technologies by 2040	Removing grid congestion hampering electrification or investment in industries requiring high electricity e.g. data centers. Completing 2024 TYNDP project portfolio would lead to mobilisation of huge amount of investment, as well as to some 4.1 million jobs in the EU
Electrification of different sectors through better grid access	Not possible to monetise benefit.	More grid capacity based on optimised grid planning and use will enable electrification of transport and industry as well as better grid access for data centres.
Greater grid security	Avoided costs of repairs - EUR 50-60 million for an undersea cable and of additional loss of economic welfare due to price increases.	Addressing security vulnerabilities would lower the costs of outage, more expensive

		power supply and repairs of sabotaged/damaged infrastructure

(1) Estimates are gross values relative to the baseline for the preferred option as a whole (i.e. the impact of individual actions/obligations of the preferred option are aggregated together); (2) Please indicate in the comments column which stakeholder group is the main recipient of the benefit;(3) For reductions in regulatory costs, please describe in the comments column the details as to how the saving arises (e.g. reductions in adjustment costs, administrative costs, regulatory charges, enforcement costs, etc.;);.

For assessing the costs of the preferred policy option, the analysis distinguishes between direct costs and indirect costs. The preferred policy option results in direct costs in terms of adjustment costs, administrative costs and enforcement costs for businesses and administrations (national competent authorities, national regulatory authorities, the Commission and ACER) in order to comply with the substantive obligations or requirements contained therein. The application of the preferred policy option could result in indirect costs for citizens/consumers and businesses in some countries where energy prices could increase due to price convergence resulting from further market integration. The European Grids Package is not envisioned to introduce any regulatory charges such as fees, levies, taxes etc. Additional enforcement costs at national and EU level will depend on the implementation.

The below table summarises the direct and indirect costs for those actions of the preferred policy options for which costs have been identified and compared to the baseline. It is not possible to estimate these costs for all actions at this stage, but where they are not included they are considered as non-significant.

II. Overview of costs – Preferred option								
		Citizens/Consumers		**Businesses**		**Administrations**	
		One-off	**Recurrent**	**One-off**	**Recurrent**	**One-off**	**Recurrent**
PO2	Direct adjustment costs	N/A	N/A	N/A	TSO: Ensure data collection for the scenario development and follow-up of identified infrastructure needs (gap filling mechanism).	EC: Building capacity to take over some planning activities. NCA: Set up a digitalised permitting system and data collection.	NRAs: Regulation of projects outside their territory and to cooperate in groups with NRAs and TSOs from different Member States under the cost-sharing framework.
	Direct administrative costs	N/A	N/A	N/A	TSOs/Project promoters: New security reporting and risk mitigation requirements which would affect a small share of TSOs/project promoters.	ACER: framework methodology for the identification of infrastructure needs (grouped together with 2 FTEs for data verification for scenario development)	EC: 18 FTEs & EUR 0.5 mln in external costs for implementing new planning tasks. NRAs & ACER: to ensure data verification for

						ACER: implementation costs to update its CBCA recommendation (and develop a template (estimated 1 FTE).	the scenario development as well as verification, approval, and follow-up of identified needs (gap filling mechanism). 2 FTEs for ACER. NCA: Increase resources to deal with tighter permitting deadlines.
	Direct regulatory fees and charges	N/A	N/A	N/A	N/A	N/A	N/A
	Direct enforcement costs	N/A	N/A	N/A	N/A	N/A	NRAs: Additional resources for better enforcement of the regulatory framework.
	Indirect costs	N/A	Higher electricity prices in some countries due to price convergence impacts. Possible higher network tariffs	N/A	Higher electricity prices in some countries due to price convergence impacts. Possible higher network tariffs	N/A	N/A

(1) *Estimates (gross values) to be provided with respect to the baseline; (2) costs are provided for each identifiable action/obligation of the* <u>*preferred*</u> *option otherwise for all retained options when no preferred option is specified; (3) If relevant and available, please present information on costs according to the standard typology of costs (adjustment costs, administrative costs, regulatory charges, enforcement costs, indirect costs;).*

III. Application of the 'one in, one out' approach – Preferred option(s)			
[M€]	**One-off**	**Recurrent** (nominal values per year)	**Total**

	(annualised total net present value over the relevant period)		
Businesses			
New administrative burdens (INs)	N/A	TSOs/Project promoters: New security reporting and risk mitigation requirements. Cannot be quantified at this time but expected to be limited.	A slight increase in administrative burden for TSOs and project promoters.
Removed administrative burdens (OUTs)	N/A	ENTSOs & TSOs: Reduced frequency of TYNDP process and Commission taking over central scenario development = savings of between EUR 2 and 4 million per year. TSOs/project promoters: simplified application and evaluation process for mature PCIs and PMIs. Expected savings per PCI/PMI list between EUR 0.25 and 0.5 million. Streamline permitting procedures will reduce costs, accelerate project deployment, and improve certainty. Cannot be quantified at this time.	A significant reduction of the administrative burden for ENTSOs, TSOs and project promoters.
Net administrative burdens*	N/A	Savings of at least between EUR 2.5 and 4.5 million.	
Adjustment costs**	N/A	TSO: Ensure data collection for the scenario development as well as follow-up of identified needs (gap filling mechanism). Cannot be quantified at this time.	
Citizens			
New administrative burdens (INs)	N/A	N/A	N/A
Removed administrative burdens (OUTs)	N/A	N/A	N/A
Net administrative burdens*	N/A	N/A	N/A
Adjustment costs**	N/A	N/A	
Total administrative burdens***	**No administrative burden is expected for citizens.**	**The total recurrent administrative burden would be significantly lowered (negative), due to simplified infrastructure**	**The total administrative burden would be significantly lowered (negative), as the increase in**

		planning, cost-sharing and permitting procedures	**administrative costs related to new security and reporting requirements would be offset by simplified planning and permitting processes.**

(*) Net administrative burdens = INs – OUTs;
(**) Adjustment costs falling under the scope of the OIOO approach are the same as reported in Table 2 above. Non-annualised values;
(***) Total administrative burdens = Net administrative burdens for businesses + net administrative burdens for citizens.

3. RELEVANT SUSTAINABLE DEVELOPMENT GOALS

IV. Overview of relevant Sustainable Development Goals – Preferred Option(s)		
Relevant SDG	**Expected progress towards the Goal**	**Comments**
SDG no. 7 - affordable and clean energy	This targeted revision will support the impacts of the TEN-E. By achieving an expanded and modernised grid, electricity will become more easily available throughout the EU. Thus, the preferred option will strengthen market integration, increase electricity supply and enable access to affordable and clean energy. This is vital to counter growing energy poverty in the EU. All above will benefit both households and industry. More affordable electricity prices due to positive effects of greater market convergence will especially improve the competitiveness of energy intensive industries and encourage investments in decarbonisation and clean energy business models.	
SDG 9 Industry, Innovation and Infrastructure	Aim of the initiative is to achieve better planning catering for future developments of demand and supply, including in the industrial sector, as well as achieve resilient and sustainable infrastructure development. Hence it is fully aligned with SDG9, which aims to build resilient infrastructure and promote inclusive and sustainable industrialization and innovation. Regarding the latter, preferred option aims to more strongly support digital and smart grid technologies, contributing to further innovation efforts in the grid manufacturing industry.	
SDG 12 Responsible consumption and production	By fostering modernised and expanded grid the preferred option will enable the build out of renewable energies and hence a quicker phase out of fossil fuels. The digitalisation and optimisation of the grid will enable more cost-optimal dispatch and lower curtailment of renewable energy. Improved availability of renewables based on sufficient grid capacity will incentivise energy intensive industries to favour decarbonised energy consumption including both production and consumption of low carbon hydrogen. The changes in consumption trend/pattern above can be monitored.	

SDG no. 13 Climate	As above, the preferred option will support more optimal, modernized and expanded grid, which in turn will enable the integration of renewable energies and a quicker phase out of fossil fuels. Reduced fossil fuels consumption will reduce greenhouse gas emissions. As time is of the essence for avoiding irreversible damage to the climate and repercussions on biodiversity, adding renewable energy capacity is expected to be a tangible result to be measured in both time and size (installed capacity). Because the initiative prioritizes cross-border projects, efficiencies among Member States will be obtained. Through better planning, overinvestments can be avoided, hence improving the overall environmental footprint. Moreover, cross-border co-operations can stimulate innovative solutions, including the use of digital tools. Such tools can improve efficiencies, in terms of operations and maintenance, increased electricity output and reducing network losses.	

ANNEX 4: ANALYTICAL METHODS

Analysis of the needs for infrastructure and the benefits of the optimal grid

The analysis builds on the 2024 TYNDP Infrastructure Gaps Report (IGR)[161] which screens the entire European perimeter to identify potential needs in terms of increase of interconnection capacities at ENTSO-E perimeter by 2030, 2040 and 2050 time horizons.

The methodology for identifying infrastructure gaps and benefits of matching the infrastructure needs, as outlined involves several key steps:

1. **Scenarios Development**: The process begins with defining a range of possible future scenarios that test infrastructure needs. This includes assessing different possible futures and understanding infrastructure requirements at various timelines such as 2030, 2040, and 2050. The infrastructure needs assessment is based on the TYNDP 2024 National Trends+ scenarios for 2030 and 2040 and Distributed Energy scenarios for 2050.
2. **System needs identification**: This part of the study considers the European electrical system as a whole to identify where new system assets would bring benefits. It involves analysing the combination of potential network capacity increases between countries and storage that minimize total system costs. The costs include network investment, internal reinforcements, and generation costs, while maximising socio-economic welfare.

   The process involves collecting input data from different sources. This includes data related to transmission, storage projects, and potential hybrid projects focused on cross-border capacity increases. Then a general market modelling approach is undertaken where

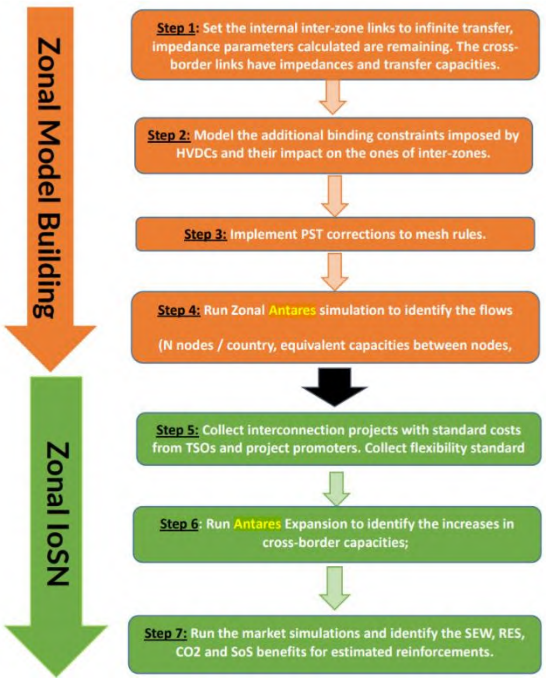
[161] ENTSO-E (2025), TYNDP 2024. Opportunities for…op. cit.

scenarios are evaluated to determine potential future energy systems. This involves simulations to check reference case congestions and identify the flows within the system.

The simulations use different approach depending on the time horizon. For 2030, NTC Model (Net Transfer Capacity model) is used for assessing transfer capacities between bidding zones or countries. A zonal market simulation is performed for 2040. It includes defining clusters for generation and load data to optimize data processing and validation based on PECD Zone Clustering Model.

In order to define clusters, first internal inter-zone connections are given infinite capacity to focus on cross-border bottlenecks, while maintaining technical constraints like impedance. HVDC links are then added, requiring special constraints due to their unique behaviour. Corrections for Phase Shifting Transformers (PSTs) are also implemented to reflect their effect on power flow, modifying mesh rules accordingly. Once the model is set, a zonal simulation is run to detect existing congestions (this represents the first modelling run). Based on this run, candidate interconnection projects are collected with standard cost data from TSOs and project promoters. These are then implemented in a capacity expansion model using Antares Xpansion, which solves for the most cost-effective set of cross-border upgrades. The optimisation relies on Benders Decomposition, which breaks the problem into manageable steps: proposing investments, simulating dispatch, calculating total costs, and refining until the cost no longer significantly improves. This iterative process intends to allow for the identification of strategic upgrades that minimise long-term system costs while ensuring security of supply and efficient integration of renewables. For 2050, Simplified Zonal Market Model is used.[162]

Figure 6: Step-by-step Identification of System Needs process diagram (TYNDP 2024 for 2040-time horizon)



Source: ENTSO-E Identification of the System Needs Study Methodology

[162] ENTSO-E (2025), TYNDP 2024. Identification of the System Needs Study Methodology

The optimization of the grid where it would minimise the total system costs is performed in two phases:

- The first phase considers only existing projects, collected from project promoters, on top of the ones already included in the reference network and based on TSO submission (Third party and TSOs). For battery and flexibility candidates, the only capacities considered in this phase are the ones removed from starting point.
- The second phase considers conceptual candidates added to candidates that were not selected from the first loop of optimization. These include conceptual interconnections, collected from TSOs, hybrid projects, collected from regional groups, and normative flexibilities.

In the 2024 System Needs assessment, the H2 system is also modelled, adding complexity to the data collection (performed in the Scenario Building process) and the computation. The results allowed for a following process that intends to capture the hydrogen infrastructure gaps in Europe.

3. **Infrastructure gaps identification:** This part of the study identifies where there is a potential difference between cross-border capacity needs and the expected increases from transmission projects to be developed in the future. Thes projects represent investment candidates submitted by project promoters and are largely in line with the TYNDP 2024 projects portfolio. This analysis helps map where there are opportunities for new solutions to increase capacity.

The benefits of an optimal grid are assessed by looking among others at:

1.1. **Socio-Economic Welfare (SEW)** which reflects the sum of economic surpluses for electricity consumers, producers, and transmission owners. It measures how much more efficient and beneficial the grid becomes by enhancing cross-border transmission and reducing congestion.

1.2. **Reduction in system costs** estimating reductions in total system costs, like network investment, internal reinforcement, and generation costs, achieved by optimizing grid capacity and eliminating constraints.

1.3. **Integration of renewable energy sources** which is based on the ability of the optimal grid to integrate and utilize renewable energy, thereby reducing reliance on fossil fuels, decreasing carbon emissions, and supporting sustainable energy goals.

1.4. **Avoided curtailment** where the assessment considers the reduction in curtailment (unused renewable power due to grid constraints) as a significant grid optimization benefit by maximizing the use of generated renewable energy.

1.5. **Reduction in CO_2 emissions** which includes evaluating how better cross-border integration and increased capacity for renewable energy contribute to decreases in CO_2 emissions, aligning with environmental targets.

1.6. **Economic and market benefits** looking at how an optimal grid enables more competitive electricity pricing by facilitating market integration and reducing regional price disparities. It leads to lower electricity bills and broader economic benefits.

Infrastructure needs assessment by JRC

The JRC assessment applies the same logic to the infrastructure needs assessment as the ENTSO-E IGR, but uses a different model (METIS 3) and introduces some adjustments to make the assessment more in line with the latest policy developments. The analysis is based on the National Trends + scenario 2030 and 2040, while the investment candidates and their costs used for grid optimisation come from:

- Explicit TYNDP candidates and their costs cost,
- Generic expansion candidates,
- Complete bidirectional line setup (LU),
- Candidates from scenario results.

The reference grid and the expansion candidates for the expansion study provide a modelling setup for METIS. The nodes are divided into those at which installed generation capacities or demand is located and nodes which have neither. The METIS scenario is parametrised to closely resemble the TYNDP National Trends+ scenario, but some differences remain. The model produces some additional outputs such as average electricity prices after the line expansion.

Analysis of the delays in infrastructure deployment

The analysis has been performed by the JRC based on the 2024 TYNDP National Trends + data and METIS model optimisation, and based on data on delays coming from 2020 to 2026 TYNDP project collections.

The quantification of costs of delays looks at 2030 comparing a situation with projects expected initially to be completed by 2030 (No delays case) to a situation without the projects whose commissioning dates were moved to 2030 and beyond (delayed scenario). The expected grid in 2030 contains:

- ENTSO reference grid (aggregated per border) for 2030
- any additional project candidates with initial commissioning dates by 2030 (data coming from previous TYNDPs)

This forms the “No delays case” with additional MW and annualised CAPEX and OPEX of each candidate.

In the delayed scenario, the projects with delays leading to commissioning dates beyond 2030 have been removed from METIS optimisation (the latest data comes from information provided by project promoters in the context of the 2nd PCI/PMI list and project submissions to the TYNDP 2026).

The analysis covers only transmission projects, meaning that the effects of delayed storage projects are not included in the METIS contexts.

The impact of the delays was estimated in terms of:

- Average price per zone and scenario and delta of delay scenario compared to the No Delays case;

- Delta in Social Economic Welfare to the No Delays case;
- Total cost of generation (fuel cost, emission certificates, variable O&M) and delta to No Delays case;
- Investment costs compared to the delayed projects.

Analysis of the benefits of dynamic line rating deployment

Commission analysis used available data from Joint Allocation Office (JAO - Leading service provider for TSOs), from the common grid model and results of shadow pricing in the period of April 2022 to June 2025. It analysed 143 most congested lines in the CORE region (i.e., their aggregated share in total shadow prices <99%, lines with frequent changes to Fmax were filtered out before the calculation), and applied dynamic line rating on these lines (assumptions: increase of available maximum flow Fmax by 20 % in 1/3 of the year, 70 % of such increase available for cross-border trade). Yearly shadow prices were discounted by 0.5 % annually due to expected decrease of the shadow prices, and benefits were calculated per expected life-duration of 20 years for dynamic line rating technology. Costs of dynamic line rating were taken from conservative estimate of Forbes (https://www.forbes.com/sites/annabroughel/2025/03/27/dynamic-line-rating-grid-technology-to-reduce-your-electric-bills/). For comparison, ACER estimate is 500 000 EUR for one line to be equipped by the dynamic line rating, which would result in approximately 50 % lower costs if we apply it on the identical line base. In this relation, more conservative (higher) Forbes values were chosen.

Analysis of the benefits of accelerating permitting for recharging stations

First, the high energy efficiency of EVs must be considered. While electricity accounted for only 7% of the total energy use in road transport in 2023, it powers 26% of the miles driven.[163]

Second, the ACER Market Monitoring Report shows that the need for congestion management jumped 14.5% in 2023, driving up system costs. It estimates that the costs of managing congestion in the EU power grid exceeded €4 billion. Increasingly, congestion management results in renewable energy being curtailed. Streamlining permitting procedures for recharging stations, and thus accelerating EV adoption, will contribute to limit renewables curtailment and to reduce GHG emissions thanks to smart charging, by increasing electricity demand at the right times (when clean energy is abundant) and store it for later use.

EVs can provide additional flexibility thanks to bidirectional charging, by selling energy back to the grid at peak times. EVs with bidirectional charging capabilities could contribute up to 4% of Europe's annual power supply by 2030. Estimated at 114 TWh battery capacity, it is enough to power 30 million homes every year.[164] By 2040, EVs utilizing bidirectional charging could supply up to 9% of Europe's annual electricity demand, positioning them as the fourth-largest electricity provider in the region.[165] During peak times, EVs could supply up to 15–20% of electricity demand, serving as a large virtual power plant.[166] The economic benefits might raise up to €22 billion per year in savings for EU energy systems by 2040 through vehicle-to-grid

[163] IEA, Global EV Outlook 2023
[164] EY/Eurelectric report, Plugging into potential: unleashing the untapped flexibility of EVs, March 2025
[165]Fraunhofer study for T&E, Batteries on wheels: the untapped potential of EVs, October 2024
[166] Fraunhofer study for T&E, Batteries on wheels: the untapped potential of EVs, October 2024

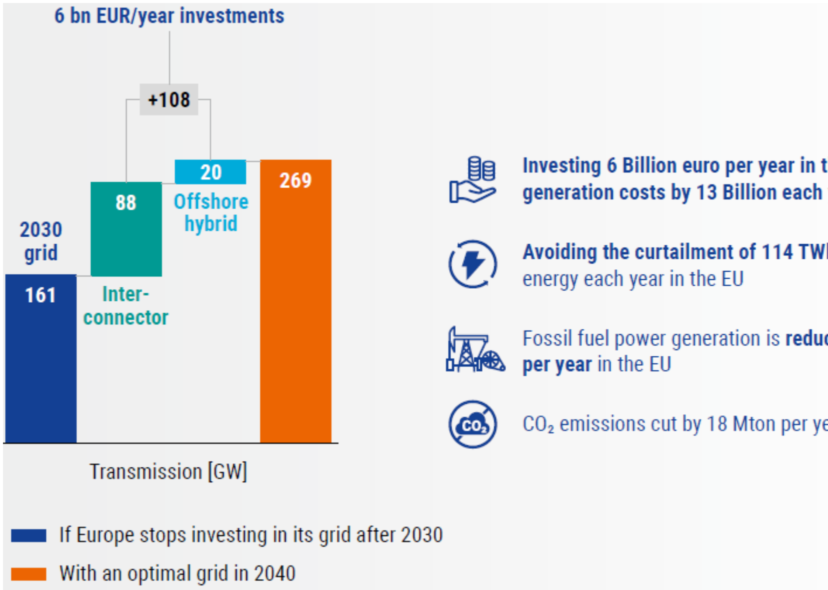
(V2G) integration.[167] Moving to smart and bidirectional charging could save family car owners an average of 20% on total cost of vehicle ownership.[168] Electric bus fleets could even reduce their charging costs, a primary component of their operating expenditure, by more than 90% with V2G.[169] In terms of GHG emissions, by 2035, V2G could reduce CO_2 emissions by 60 million tonnes per year in Europe through reduced use of fossil-fuel generation at peak.[170] Cumulative savings (2025–2040) could reach 350 – 450 Mt CO_2 .

Additional evidence from other studies or assessments

Economic impacts - benefits from optimised grid in 2040:

As set out in section 6.1.1, for 2040, investments of EUR 6 bn/year into the optimal grid would lead to EUR 14 bn/year reduction in system costs, that is EUR 8 bn/year net saving (only part of these savings could be achieved by the already planned projects under the BAU scenario, corresponding to 78 GW new capacity to be added by 2040). Figure 7 provides a more detailed overview on the expected benefits.

Figure 7: Expected benefits from optimised grid in 2040



Source: ENTSO-E, TYNDP 2024 Infrastructure Gap Report

Economic impacts - congestion income:

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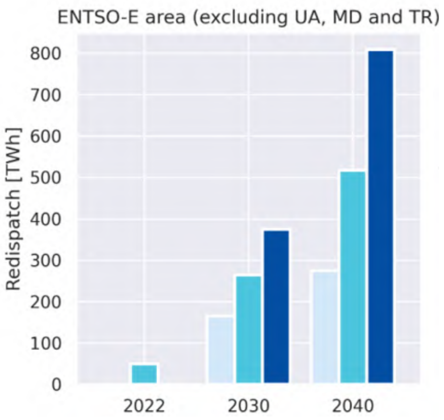
[167]Fraunhofer study for T&E, Batteries on wheels: the untapped potential of EVs, October 2024
[168] EY/Eurelectric report, Plugging into potential: unleashing the untapped flexibility of EVs, March 2025
[169] https://www.sciencedirect.com/science/article/pii/S136655452300073X
[170]Fraunhofer study for T&E, Batteries on wheels: the untapped potential of EVs, October 2024

Further to the assessment in section 6.1.1, in 2021, NRAs reported to ACER on the use of EUR 6.9 billion of overall congestion income.[171] 45% was used on the priority objectives[172], and 49% was saved on internal accounts. The remainder 6%, was used partly to reduce tariffs and partly to cover tax obligations incurred by the transmission system operators.[173] For 2024[174], the total congestion income collected was around EUR 8.4 billion with around EUR 5 billion spent on the priority objectives and more than EUR 1 billion for tariff reduction and electricity customers' support.[175] As a result, around EUR 2.4 billion is expected to be stored. Of the EUR 5 billion spent on the priority objectives, around EUR 1 billion was used for "ongoing investment or capital expenditures for renewal, replacement, reinforcement of existing assets, or new assets which significantly contribute to maintaining or increasing cross-zonal capacity, including the costs of development and construction phases of such assets".

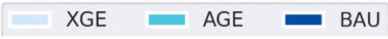
Economic impacts - redispatch volumes:

In addition to the assessment in section 6.1.1., the below figure shows the evolution of redispatched volumes in European system in three scenarios done by the JRC: business as usual (10 % of grid expansion by 2040), ambitious grid expansion (20% increase of grid capacity by 2040) and extreme grid expansion (35 % increase of grid capacity by 2040). Redispatching significantly drops between BAU and AGE, and further in XGE scenario (see Figure 8).[176] Of the total amount of electricity redispatched, between 50-120 TWh will be of renewable origin in 2030, and between 100-310 TWh in 2040 (depending on the scenario). These numbers confirm that appropriate grid expansion can significantly lower environmental losses linked to curtailed electricity from renewables. (See estimation of ENTSO-E in the following paragraph, noting that optimal grid would decrease curtailed RES by 143 TWh in 2040, matching the middle JRC scenario).

Figure 8: Evolution of redispatch volumes in the European power system



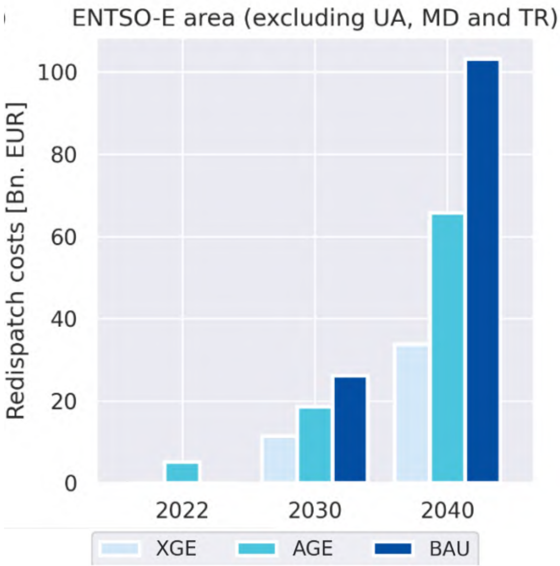
[171] ACER. (2022). Use of Congestion Income 2021 ACER Monitoring Report. 10.1 Use of Congestion Income 2020
[172] Article 19(2) of Regulation (EU) 2019/943. Priority objectives include a) guaranteeing the actual availability of the allocated capacity including firmness compensation and b) maintaining or increasing cross-zonal capacities through optimisation of the usage of existing interconnectors by means of coordinated remedial actions, where applicable, or covering costs resulting from network investments that are relevant to reduce interconnector congestion.
[173] CERRE_Infrastructure_Final-report.pdf
[174] Congestion revenues for the years 2022 and 2023 are not considered representative due to the energy crisis and therefore are not included here.
[175] ACER data
[176] This JRC study does not identify optimal grid as such, which represents a shortcoming. To this aim, we do not show results compared per policy option, but only for illustration of potential positive benefits from avoided RES curtailment perspective.



Source: JRC analysis

Figure 9 shows the expected redispatching costs under different grid development scenarios (BAU, Ambitious Grid Expansion (AGE) and Extreme Grid Expansion (XGE)) as shown below from the JRC analysis.

Figure 9: Evolution of redispatch costs in the European power system (JRC, 2024)

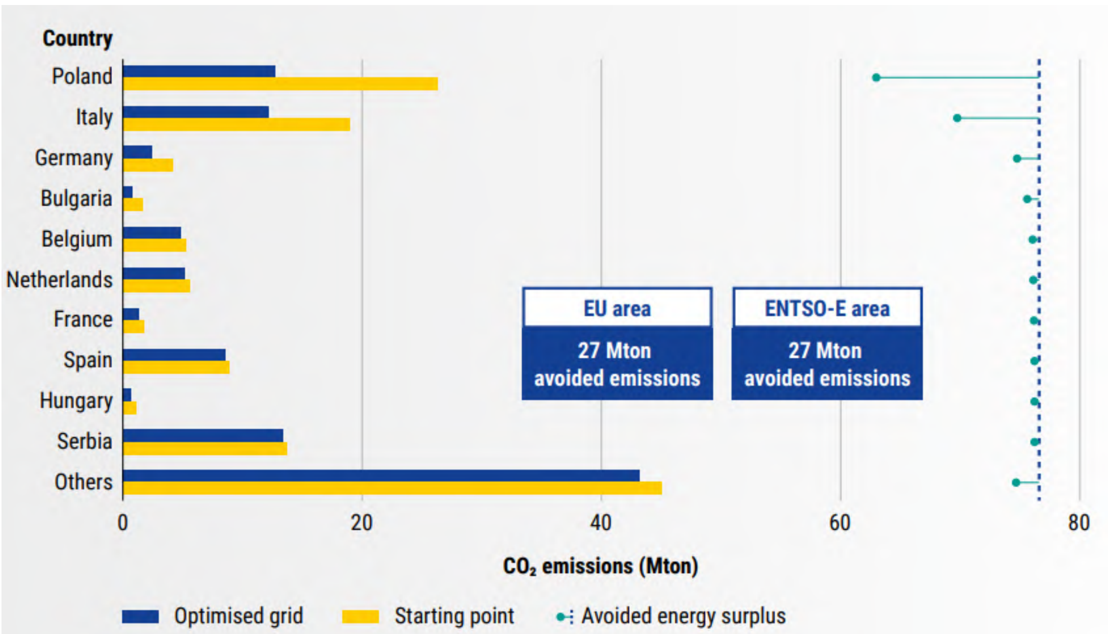


Source: JRC analysis

<u>CO_2 emissions decrease for optimised grid:</u>

Figure 10 provides a more detailed overview on expected CO2 emission reductions for certain countries as set out in section 6.3 on environmental impacts.

Figure 10: CO_2 emissions decrease for optimised grid, source: ENTSO-E 2024 TYNDP



Administrative costs:

Policy option 3:

The most substantial administrative costs are expected for **PO3** and the establishment of entities responsible for infrastructure planning and permitting. To estimate the administrative costs of setting up an entity to cover all tasks in relation to infrastructure planning (PO3), the current budget of ENTSO-E and ACER can serve as examples. For 2023, the budget of ENTSO-E[177] totalled EUR 61.2 million, mostly funded by TSO member fees. As of 31 December 2023, ENTSO-E counted 145 employees including permanent staff and secondments from TSOs. In addition, ENTSO-E is relying on "numerous" TSO staff members to bring in their expertise to execute their tasks. While infrastructure planning is only one of ENTSO-E's tasks, the entity would also cover hydrogen infrastructure planning which is currently with ENTSO-G and ENNOH. In comparison, ACER's total budget for 2023 was EUR 30 million, with 152 permanent staff divided in three main areas: energy market and system needs, REMIT and horizontal activities[178]. For the entity, staffing of 50 FTEs with an annual budget of around EUR 10-15 million might be required to carry out all tasks. While there might be some offsets due to staff transfers, a substantial part would be in addition to the budget required to operate the already existing entities. Since the entity would be independent from TSOs/project promoters, the budget would have to be financed from other sources than membership fees. Whereas some posts of the current entities might be transferred to the entity, all horizontal functions would have to be established for a new entity (e.g. legal, finance, HR, IT).

Given the highly specialised tasks, the establishment of such an entity and the time for it to become fully operational is likely to take several years which would further delay the expected benefits and hence increase costs in terms of non-realised benefits. It is expected to be very difficult to hire highly specialised staff with sufficient experience in network operation, which is intrinsically linked with network planning as well as responsibility for security of supply. Substantial costs are expected to ensure full consistency of the complex network models required by the entity for grid planning and the network models used for other tasks by the already existing entities, e.g. system operation. The split between tasks related to planning (newly established entity) and operation (ENTSOs/TSOs) across different entities entails substantial risks of inconsistencies possibly affecting energy security and questioning liability of respective actors.

For cost and benefit sharing, the administrative costs are highest for PO3 on the side of the Commission, Member States, NRAs and system operators, where regional planning and cost-sharing are mandatory for some offshore sea basins where hybrid or cross-border radials are planned. In the short term, this is expected to mainly affect North Sea Member States. Nevertheless, North Sea TSOs, under the OTC, and Member States, under NSEC, have already initiated this process saving some of the necessary resources in the region.

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[177] ENTSO-E: Annual Report, 2023 Edition, https://consultations.entsoe.eu/entso-e-general/have-your-say-on-the-entso-es-annual-report-2023/supporting_documents/ENTSOE%20ANNUAL%20REPORT%202023.pdf

[178] ACER (2025): Consolidated annual activity report 2024, https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER-Consolidated-Annual-Activity-Report-2024.pdf

On permitting, PO3 would require, in addition to the costs of PO2, the setting up of a coordination entity at the European level. Such a body would be expected to coordinate permitting procedures for at least 250 projects with a cross-border dimension[179]. To do so, it will have to liaise with national and local authorities for authorisation. Taking a conservative assumption, this would require 50 FTEs, representing a total budget, including overhead, of at minimum, EUR 10 million per year. Further, PO3 is unlikely to save resources in local administration who would still have to perform the national/local level assessment and implement the decisions on the ground and not preclude the need for reinforcement of the national permitting authorities with additional staff and tools, given that for sovereignty reasons these are still necessary and responsible for the final decisions concerning the projects in question.

[179] Assuming 220 PCIs and PMIs per Union list and additional cross-border renewable and storage projects.

ANNEX 5: COMPETITIVENESS CHECK

1. OVERVIEW OF IMPACTS ON COMPETITIVENESS

Dimensions of Competitiveness	Impact of the initiative (++ / + / 0 / - / -- / n.a.)	References to sub-sections of the main report or annexes
Cost and price competitiveness	+	6.1.1. and Annex 3
International competitiveness	+	6.1.2.
Capacity to innovate	+	6.1.2. and 6.1.3.
SME competitiveness	n.a.	

2. SYNTHETIC ASSESSMENT

Cost and price competitiveness

Expanding and modernising EU grids will improve access to electricity and increase supply. All other things equal this will reduce the price of electricity, and thus the production costs of companies dependent on electricity as an input to perform their activities. Examples of companies that are particularly energy intensive are Data Centres, Chemical and Petrochemical Industry, Non-Metallic Minerals Industry, Iron and Steel Industry. These industries not only consume large amounts of electricity but also contribute significantly to the EU's GDP and employment. For these industries, lower electricity cost imply that they can improve productivity, i.e. produce more with the same input, or maintain production levels and save costs. Both of which supports higher margins that can benefit owners (shareholders), employers (higher wages) and/or the business itself if profits are fully or partly invested in business development, e.g. by upgrading facilities and enhancing innovation.

For low-carbon hydrogen, cost levels are high in the entire value chain, especially in the production phase which depends on electricity (and water) for electrolysis. Reducing electricity prices is therefore enabling the EU to reach ambition levels for domestic hydrogen production and derivatives, both of which are essential to transform the hard-to-abate sector and the transport sector that will have to transform away from fossil fuels to low-carbon alternative fuels.

A modernised grid with smart technologies will also entail more flexible grids allowing for active demand response, including electricity storage. Storage can also resolve congestion and curtail the need for new investments. Thus, an updated grid can both reduce capital costs and smoothen out price peaks.

Eventually, accelerated permitting, will ensure a that infrastructure projects will be completed in a shorter timeframe, which means that the net present value of the projects will increase. This improves the rate of return for investors and value added for the society.

The initiative is also expected to overall significantly reduce compliance costs for companies, including system operators, project promoters and renewable energy generators, through a simplification and streamlining of processes (see Annex 3).

International competitiveness

There are many factors driving international competitiveness, including productivity and costs. Lower electricity costs can also help reducing market prices without squeezing margins. For companies that are competing on an international level, this will enhance their competitive position. Being competitive in export markets usually entails tougher competition than at home (EU) e.g. due to different legal requirements, higher transportation costs, more established competitors etc. Hence, even marginally lower prices can be a decisive factor for international competitiveness and market entry in third countries and overseas markets. Furthermore, for the EU to be attractive for foreign direct investments, energy infrastructure plays a key role as it underpins market efficiency and enables industry development.

Capacity to innovate

There are two ways that the Grids Package will increase the capacity to innovate.

First, EU's ambitions to accelerate the roll-out of renewables are based on a set of plans to guide these endeavours, such as the NECP, TYNDP, ONDP, Non-Binding Agreements. These plans also set the stage for a more predictable and transparent framework for short-term and long-term grid investments. Such a framework is also conducive for related R&I investments, be it among project developers, suppliers or research institutions. For instance, a resilient and reliable grid must be based on digital solutions and Artificial Intelligence.

This will require technology development and competencies to ensure that state of the art solutions will be deployed going forward. Such R&I efforts need sustained funding. Hence, by providing a more predictable policy framework, the grids package will provide a strong incentive for capacity building in both the industry and the research community.

Second, the transparency and predictability described above will improve demand certainty for the various players in the grids supply chain. Demand certainty tends to spur competition and hence innovation, including new goods and services, as well as novel manufacturing and business processes. The latter includes distribution, marketing and after-sales.

SME competitiveness

This initiative is not expected to have specific implications on SME competitiveness in addition to the above considerations on competitiveness.

3. COMPETITIVE POSITION OF THE MOST AFFECTED SECTORS

Apart from being an enabler for the renewable energy sector and underpinning the hard-to-abate and energy intensive sectors mentioned above, improved access to a modernised transmission and distribution grid will contribute to strengthen the competitive position of other industries.

Accelerating permitting procedures for recharging points will unlock faster infrastructure rollout, which improves planning certainty, lowers costs, improves reliability, and levels the playing field with fossil fuels, making the e-mobililty sector more competitive, sustainable, and attractive for investment. As e-trucks are ramping up, it's crucial to ensure a proper roll out of infrastructure, in order to give visibility to companies and encourage them to make the switch.

ANNEX 6: EXISTING LEGAL EU FRAMEWORK

A) Infrastructure planning and use

Existing legal requirements for planning of transmission and distribution network development at EU, regional and national level are included in the Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure (TEN- E Regulation), Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity (Electricity Directive), Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (Electricity Regulation) as well as the Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen (Gas Regulation) and Directive (EU) 2024/1788 of the European Parliament and of the Council of 13 June 2024 on common rules for the internal markets for renewable gas, natural gas and hydrogen (Gas Directive).

Planning at EU level (electricity, gas and hydrogen)

Based on the requirements of the Electricity Regulation (Article 30) and Gas Regulation ENTSO-E and ENTSO-G (and starting with 2027 ENNOH, Articles 32, 60, 61) and the TEN-E Regulation (Article 12) adopt biennially the EU-wide Ten-Years Network Development Plan (TYNDP). It covers the period of the next 10 years with an outlook for 2040 and 2050 and comprises a system needs identification based on the joint scenarios, as well as projects, which are submitted by respective TSOs and project promoters.

Pursuant to Articles 26 and 60 of the Gas Regulation, TYNDPs for natural gas and for hydrogen are of a non-binding character. As of 2026, there should be one TYNDP for natural gas and hydrogen, with two interlinked chapters.

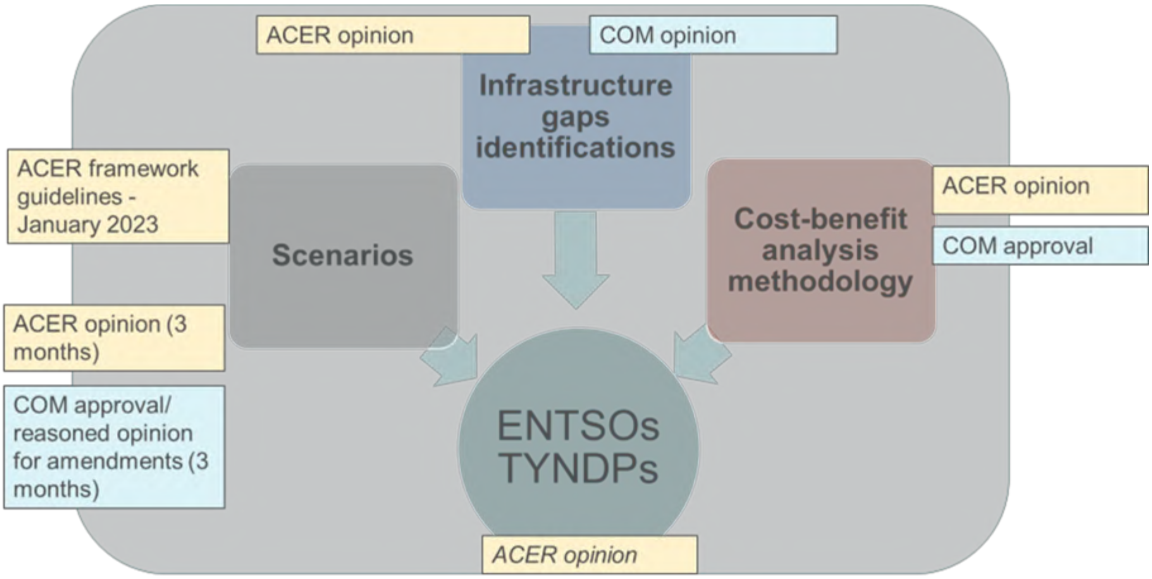
Based on Article 12 of the TEN-E Regulation, the joint scenarios for electricity, natural gas and hydrogen network development may take into account the NECPs and should be developed based on Framework Guidelines delivered by ACER (which are however of non-binding nature). Plans should also consider national plans and regional investment plans, as well as offshore non-binding agreements pursuant to Article 14 of the TEN-E Regulation. Scenarios are approved by the European Commission, who can also provide a reasoned opinion to ENTSO-E, ENTSO-G and ENNOH in case it does not approve the joint scenarios report.

The infrastructure gaps report follows as a second step after the scenarios' development. Based on the results of the scenarios as well as projects submitted by project promoters, ENTSOs develop infrastructure needs analysis, which should contain estimate of future infrastructure needs for 2030, 2040 and 2050. Infrastructure needs are compared with the starting grid, which is set based on the project collection made by ENTSOs. ENTSOs and ENNOH are obliged to consider with priority all relevant alternatives to new infrastructure and consider energy efficiency first principle when assessing the infrastructure gaps. With regard to timing, infrastructure projects' collection, including data collection on project costs and technical parameters, starts approximately 2 years before the final TYNDP is published.

TYNDP as such is then developed based on joint scenarios, considering the Energy system wide Cost benefit analysis (CBA) methodology pursuant to Article 11 of the TEN-E Regulation. This methodology is approved by the Commission. The ENTSOs (and in the future ENNOH) assess the benefits of respective projects that are submitted for the TYNDP and may subsequently be submitted as candidates to the PCI/PMI selection process. Results are published in respective project sheets as part of the TYNDP. There is currently no comparison among the projects as part of the TYNDP (for instance among the projects addressing the same need). There is also no link between the starting grid for 2030 and 2040 and consequences for the needs assessment.

The draft results of the TYNDP are submitted to ACER for opinion (which is of non-binding character), there is no role for the Commission or Member States in the process. COM provides opinion only on the infrastructure gaps report. ACER has a monitoring role on the consistency between Union-wide TYNDP and national TNDPs and right to recommend changes in case of inconsistencies (both for electricity and gas sectors).

Most recent changes to the TEN-E Regulation (amendments of Article 11, 12 and 13), done by the Gas Regulation recast in 2024, clarified interplay with ENNOH and the hydrogen sector when it comes to sector methodologies and the integrated model. Sector methodologies for energy system wide cost-benefit analysis for the PCI and PMI selection should be harmonised across the sectors, which should be published by 1 December 2025, and should take into account development of common energy and market model. They should be updated at least every 5 years and duly consider the hydrogen sector. Progressively integrated model should be submitted by 31 October 2025 and should cover interlinkages at all stages of infrastructure planning, specifically scenarios, technologies and spatial resolution, infrastructure gaps identification in particular with respect to cross-border capacities, and projects assessment.



Regional level planning (electricity)

Article 34 of the Electricity Regulation (2019/943) requires establishing regional cooperation under the ENTSO-E and to publish biannual regional investment plans. TSOs may consequently take investment decisions based on the regional plan (i.e., there is no obligation to follow these). Pursuant to the TEN-E Regulation, PCIs need to become an integral part of the regional investment plan. In 2020 and 2022 editions of the TYNDP, these investment plans were published together with the main TYNDP. For the 2024 edition, they were published separately.

National level – transmission infrastructure (electricity)

Requirements for transmission network development plans (TNDP) are provided under Article 51 of the Electricity Directive. Based on its provisions, TSOs should submit TNDP at least every two years and publish it on their website. It should fully consider potential use of demand response, energy storage facilities or other resources as alternatives to system expansion, indicate development of main transmission infrastructure over the next ten years and detail investments to be done for the next three years. PCIs[180] shall become integral part of the TNDP pursuant to the TEN-E Regulation.

National regulatory authorities are tasked to consult all relevant or potential system users on the TNDP and are also responsible for checking the consistency with the union-wide TYNDP. Moreover, competent national authorities should also check the consistency with NECP submitted in accordance with Regulation (EU) 2018/1999. If the investments planned for the next three years are not executed, the Electricity Directive gives the NRA right to require the execution of investment by the TSO or to organise a tendering procedure in this regard. NRAs are also required to monitor the implementation of the TNDP, however no specific deadlines or frequency is currently given by the legislation framework.

National level – distribution grid (electricity) – planning, as well as incentives for smart grids and efficient allocation of grid capacity

For the distribution grid level, the Article 32 of the Electricity Directive requests at least biennial publication of the distribution network development plan (DNDP). Plans should provide an outlook of grid development in the next 5 to 10 years, counting in flexibility needs, use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion. DNDPs should be duly consulted, including with the TSO, and submitted to the NRA. The NRA may request amendments to the plan. Currently, there is no monitoring role foreseen for the NRA. There are also no provisions in case there is an inconsistency of the DNDP with the TNDP, on scenarios or assumptions used.

There is a possibility to exempt DSOs with less than 100,000 customers from the planning, if regulated on a national level. Pursuant to ACER findings[9], two thirds of the DSOs in the EU are exempted from the preparation of the DNDP. Exempted DSOs serve between 0.7 % of customers in Latvia and around 25 % of customers in Germany. This still results in some 963 DNDPs in Europe, which are to be published on respective DSOs websites pursuant to the Electricity Directive.

When it comes to efficient grid utilisation, the Electricity Market Regulation specifies incentives for DSOs and TSOs in Article 18, which includes incentivising anticipatory investment, as well as entails that the tariff methodologies should facilitate digitalisation and solutions to optimise the existing grid, as well as and other measures fostering energy efficiency and integration of renewable energy sources.

Further requirements on grid access, grid connections and grid hosting capacities transparency, as well as use of flexibility in grid operation and planning are specified in Article 6, 6a and 32 of the Electricity Market Directive, and Article 50 and 57 of the Electricity Market Regulation (which also include notion of coordination between DSOs and TSOs).

Article 6 of the Electricity Market Directive stipulates that access to grids shall be applied objectively and without discrimination between system users. It allows the option of refusing access if the grid lacks the necessary capacity and based on objective and technically and economically justified criteria. Article 6 hence provides flexibility for Member States to adjust connection procedures based on specificities of their respective systems. Article 6a further requires Member States or NRAs to set up flexible connection agreements in areas where there is a lack of grid capacity. Article 31 of Electricity Directive stipulates transparency on grid

[180] This does not apply to competing projects or projects that have not reached a sufficient degree of maturity.

hosting capacities and treatment of grid connections by grid operators, including on the rejected ones. Specifically for grid connection requests, it requires DSOs to provide an option of fully digital connection procedure. Provisions under Articles 6a and 31 were included in the Electricity Market Directive by 2024 reform, to tackle rising grid connection queues.

Article 32 of the Electricity Market Directive mentions that DSOs should consider, when planning their networks, alternatives to system expansion. Article 59 tasks NRAs to monitor and assess the performance of system operators when it comes to the development of a smart grid, which promotes energy efficiency and integration of energy from renewable sources. These two Articles together with Recital 51 explain that smart and digital solutions should be considered as a way to modernise distribution networks.

Currently, there is also ongoing work on the network code on demand response, which was submitted by ACER to the Commission on 7 March 2025. Draft provisions target coordination between TSO-DSO and DSOs, entail clarifications on methodology for planning and scenarios and on link to flexibility needs assessment, use of local services as alternatives to grid development, monitoring of DNDPs, more transparency on public consultation as well as on publication of DNDPs. Comitology on the network code is planned for Q1 2026.

National level – integrated network planning for natural gas and hydrogen, transmission and distribution

For the gases sector, the new Gas Directive introduced obligations for integrated network planning under Chapter VIII, Articles 55-57. Similarly, as in electricity, there is a requirement to publish biennial TNDPs for natural gas and hydrogen, either jointly or separately. In either case, modelling should be done separately for each energy carrier. However, this is complemented by a requirement to have a joint scenario developed every two years between the relevant infrastructure operators, including relevant DSOs, of at least natural gas, hydrogen, electricity and, where applicable, district heating. Such scenarios shall take into account demand-side solutions not requiring new infrastructure investments. System operators should conduct an extensive consultation process on scenario development at an early stage of the process.

The Gas Directive introduced first requirements on cooperation and coordination between hydrogen, gas and electricity transmission and distribution system operators, for instance in view of location of electrolyser facilities. Pursuant to Article 55, Member States shall endeavour to ensure coordinated planning steps of the respective ten-year network development plans for natural gas, hydrogen and electricity. The Directive does not prescribe precise procedures for such coordination mechanisms though, or coordination on scenarios development.

TNDPs for gases and hydrogen should cover the period of upcoming 10 years, contain information on concrete investments to be executed in next three years, information on decommissioning of infrastructure, and be consistent with the EU-wide TYNDP for natural gas and hydrogen, as well as in line with the NECPs. TNDPs should take into account potential for alternatives to system expansion such as demand response and follow energy efficiency first principle. The whole TNDP should be consulted and submitted to the NRA, who has a right to request amendments to the plan, as well as obligation to monitor and evaluate implementation. Mirroring requirements of the electricity directive, NRA has a right to delegate execution of investment in case investment plan was not duly followed.

On a distribution level, hydrogen distribution network development plan should be submitted every four years and shall be developed in close cooperation with DSOs for natural gas and electricity, as well as district heating and cooling operators where applicable, ensuring effective energy system integration. There is a possibility to develop a joint plan of hydrogen and natural gas networks, including decommissioning. Distribution network decommissioning plans should be based on heating and cooling plans based on Article 25(6) of Directive (EU) 2023/1791. Both plans need to be duly consulted, in line with the Union-wide TYNDP and TNDPs, as well as NECPs. NRAs approve the DNDPs and have right to request amendments to the plans.

Table 10: summary of roles and requirements

Level of planning	**Actors and Roles**
Union-wide TYNDP	ENTSOs (biennial cycle) • Developing scenarios • Developing Infrastructure gaps report • Developing TYNDP, based on the CBA methodology European Commission • Approval of scenarios for the TYNDP (biennial) • Approval of the CBA methodology s for the TYNDP (before the start of the cycle) • Non-binding opinion on the Infrastructure gaps identification ACER • Non-binding opinion on the scenarios • Non-binding opinion on the CBA methodology • Non-binding opinion on the Infrastructure gaps identification • Non-binding opinion on the TYNDP • Report on consistency of TNDP and Union-wide TYNDP
Regional investment plans - electricity	TSOs • Publishing regional investment plans bienially
TNDP - electricity	TSOs • Submit TNDP at least bienially NRAs • Consult all relevant and potential system users • Right to request amendments to the plan • Check consistency with NECPs and Union-wide TYNDP • Monitoring of implementation of TNDP (without deadlines) • Right to request investments / organise a tender if investment fails
DNDP - electricity	DSOs • At least biennial publication and submission of the DNDP • Obligation to consult all relevant and potential system users • NRAs • Right to request amendments to the plan

B) Hydrogen blending

The TEN-E Regulation of 2022 introduced a new infrastructure category, namely smart gas grids, the aim of which is to support investments which integrate a plurality of low-carbon and particularly renewable gases such as biogas, biomethane, and hydrogen, in the gas network and help manage a resulting more complex system, building on innovative digital technologies.

The category covers digital systems and components integrating ICT, control systems and sensor technologies to enable the interactive and intelligent monitoring, metering, quality control and management of gas production, transmission, distribution, storage and consumption within a gas network. Furthermore, such projects may also include equipment to enable reverse flows from the distribution to the transmission level, including the related physical upgrades if indispensable to the functioning of the equipment and installations for integration of low-carbon and particularly renewable gases. The focus is digitalisation to avoid investments that aim at the maintenance, upgrade or development of the gas network, for which support was discontinued under the 2022 TEN-E Regulation.

At the same time, the TEN-E Regulation took a prudent approach to hydrogen blending, providing in its Article 31 that hydrogen assets converted from natural gas assets falling under the energy infrastructure category set out in point (3) of Annex II may be used for transport or storage of a predefined blend of hydrogen with natural gas or biomethane only during a transitional period ending on 31 December 2029 and subject to the project promoter providing sufficient evidence, including through commercial contracts, how, by the end of the transitional period, the assets will cease to be natural gas assets and become dedicated hydrogen assets and how the increased use of hydrogen will be enabled during the transitional period, This Article does not refer to the smart gas grid category, for which no explicit transitional period is established.

After the entry into force of the TEN-E Regulation, the approach of the EU legislative framework to hydrogen blending has become more restrictive: the Gas Regulation of 2024 explains explicitly that the "blending of hydrogen into the natural gas system should be a last-resort solution, as it is less efficient compared to using hydrogen in its pure form and diminishes the value of hydrogen. It also affects the operation of natural gas infrastructure, end-user applications and the interoperability of cross-border systems. The production and use of hydrogen in its pure form and its transportation in the dedicated hydrogen system should therefore be prioritised" (Recital 74).

Accordingly, Article 21 of the Gas Regulation established a cross-border cooperation mechanism to address differences in gas quality liable to restrict cross-border flows differences. However, that mechanism only applies to hydrogen blends where the hydrogen content blended into the natural gas system is below 2% by volume. Transmission System Operators may reject cross-border flows of natural gas with a blended hydrogen exceeding 2%.

C) Permitting frameworks

Renewable energy and co-located storage projects

The main vehicle is Directive (EU/2018/2001) on the promotion of the use of energy from renewable sources (RED). The Directive was amended by Directive (EU/2023/2413) *i.a.* with a view of setting comprehensive rules on permitting, by means of introducing Articles 15b to 16f. The transposition deadline for Member States to adopt Articles 16 and Articles 16b-16f was set for July 2024. The remainder of the provisions – mainly referring to setting the Renewable Acceleration Areas – were mainly due to be transposed by May 2025.

The importance of permitting for RES and the barriers it faces were already identified in Directive 2001/77/EC[181] of the European Parliament and of the Council, which required Member States to evaluate the permit-granting procedures in order to reduce the regulatory and non-regulatory barriers to the production of renewable electricity. Directive 2009/28/EC [182]of the European Parliament and of the Council introduced requirements to simplify the administrative procedures for renewable energy developers, whereas the Directive (EU) 2018/2001 of the European Parliament and of the Council strengthened these requirements and introduces a permitting deadline for the first time. (transposition by June 2021)

The Directive (EU/2023/2413) was the first to introduce an integrated permitting procedure, including environmental assessments, with specific rules simplifying processes and technology specific deadlines. However, it is important to note that the revised RED was predated by Council Regulation (EU/2022/2577) which set down a framework to accelerate the deployment of renewable energy and grids, which entered into force in December 2022 due to the energy crisis (2022-2023). Its provisions were applicable for 18 months from this date. Application of its certain provisions, alongside minor amendments and additions, was extended until June 2025 by Council Regulation (EU/2024/223). As from July 2025, this Regulation ceased to apply in its entirety.

Both Directive 2018/2001 amended by Directive 2023/2413 (the revised RED) and Council Regulation 2022/2577 amended by Council Regulation 2024/223 (the Emergency Regulation) were introduced to accelerate the permit-granting procedure to build, repower and operate Renewable Energy Sources' plants, their related infrastructure and co-located storage . Their scopes, albeit overlapping to substantial extent, are not identical.

The provisions of the revised RED with July 2024 transposition deadline constitute the first structured permanent EU legal baseline for the permit-granting procedure to build, repower and operate Renewable Energy Sources' plants, their related infrastructure and co-located storage. The scope of each of the Article is the following:

- Article 16: Organisation and main principles of the permit-granting procedure
    - Criteria for permitting process duration and validity of applications, incl. deadlines.
    - Streamlining of administrative processes.
    - Designation of single contact points (OSS) and its obligations towards stakeholders.
    - Provision of adequate resources to competent authorities and reskilling of staff.
    - Public availability of decisions.
    - Digitalisation of permit-granting procedures (by 21 November 2025).
- Article 16b: Permit-granting outside Renewable Acceleration Areas ("RAAs")
    - Permitting timelines: <2 years, <3 years for offshore, <1 year for repowering, <2 years for offshore repowering.
    - All relevant environmental assessments for a renewables project to be rolled into one single procedure.
    - The killing or disturbance of species protected under the Birds & Habitats Directives will not be considered 'deliberate' where a project has followed all necessary mitigation measures.
- Article 16c: Permit-granting for repowering

[181] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market; OJ L 283, 27.10.2001, pp. 33–40

[182] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC (Text with EEA relevance), OJ L 140, 5.6.2009, pp. 16–62

- Permitting timelines: <3 months for grid connections.
- Screening limited to extension of existing projects.
- Exemptions available for solar installations from screening and environmental assessments when no extra space is required.

➢ Article 16d: Permit-granting for solar installations on artificial structures

- Permitting timelines: <3 months for solar equipment on artificial surfaces and co-located storage with possibility for applying exemptions, and <1 month for solar equipment with capacity of 100 kW or less.
- Positive silence for solar equipment with capacity of 100 kW or less.
- Exemptions available from screening and environmental assessments.

➢ Article 16e: Permit-granting procedure for heat pumps

- Permitting timelines: <1 month above 50 MW, <3 months for ground source heat pumps, <2 weeks for connections to the grid for lower capacity MW/self-consumers).

➢ Article 16f: Presumption of overriding public interest (OPI)

Permitting, planning, construction and operation of RES plants, their related infrastructure and storage assets must be presumed to be in the OPI for the purpose of the application of certain exemptions regulated in certain environmental directives.

As already mentioned, the scope of the Emergency Regulation was to wide extent similar, with two main measures going beyond what has been laid down in the Revised RED:

➢ Article 3(2): Priority to be given to renewable energy plants and the related grid infrastructure, when balancing legal interests in the individual case, at least for projects which are recognised as being of OPI

➢ Article 3a: Binding guidance on the assessment of alternatives to the projects and possibility to advance with projects in parallel to introducing compensatory measures.

Hydrogen projects

The baseline for permitting of hydrogen infrastructure permitting, the main baseline has been established in Article 8 of the Gases Directive, but where assets fall under the scope of Article 15 and Articles 15b to 17 of the revised RED that regime shall apply.

- Article 8(5) of the Gases Directive establishes a 2-year maximum duration for authorisation procedures[183] for the construction or operation of hydrogen production facilities and hydrogen infrastructure, including pipelines or associated equipment. However, this does not include the time required for Environmental Impact Assessments required under Directive 2011/92/EU.
- Article 8(8) of the Gases Directive requires Member States to establish one or more contact points that shall, upon request from an applicant, facilitate and guide the applicants through the authorisation procedure, until a decision is rendered by the responsible authorities. This authority shall act as a single point of contact, with the applicant not being required to contact other contact points for the entire process.
- Article 8(9) of the Gases Directive, requires Member States to ensure that authorisations for the construction and operation of natural gas system infrastructure also apply to hydrogen system infrastructure, to the extent they comply with technical safety rules.

[183] Be it a licence, permission, concession, consent or approval.

Further, Article 8(10) provides that Member States shall ensure that existing land-use rights for the construction and operation of natural gas pipelines and other network assets is also applied to pipelines and other network assets for the transport of hydrogen.

Projects of common interest and projects of mutual interest

Projects of common and mutual interest benefit from a dedicated permitting regime under chapter III of the TEN-E Regulation. This regime is flexible and leaves space for diverse implementation by Member States depending on the pre-existing organisation of the national systems

- Article 7 of the TEN-E Regulation requires PCIs and PMIs are considered as being necessary from an energy and climate policy perspective and granted the status of the highest national significance in any decisions issued in the permitting granting process. In that sense project promoters and all authorities concerned are required to ensure that permitting files are treated in the most rapid way possible in administrative and judicial procedures.
- Article 8 of the TEN-E Regulation requires Member States to designate a single national competent authority responsible for facilitating and coordinating the permit granting process for PCIs and PMIs in line with the competences and responsibilities afforded to them under the scheme selected by the Member State out of the options provided in the Regulation:
    - Integrated Scheme – Comprehensive permitting decision is issued by the national competent authority and shall be the sole legally binding decision arising from the permit granting procedure. Other authorities concerned may, in accordance with national law, give their opinion as input to the procedure
    - Coordinated Scheme – Comprehensive permitting decision comprised of multiple individuals legally binding decisions issued by several authorities concerned, which are coordinated by the national competent authority. National competent authority may take decisions on behalf of other authorities concerned if it considers that has either not decided in time limit or it considers that it is not sufficiently substantiated.
    - Collaborative scheme – Comprehensive decision comprised of multiple individual legally binding decisions issued by several authorities concerned. National competent authority coordinates the process, establishing time limit for individual decisions of concerned in line with the time limits set by TEN-E, and monitoring their conformity.
- Article 9 of the TEN-E Regulation establishes the baseline in terms of public participation during the permitting procedures, requiring early public consultation, before the project promoter submits the final and complete application file to the national competent authority. It requires that a report summarising the results of public participation activities and a report explaining how the opinions expressed in the public consultations were considered, are submitted alongside the application file.
- Article 10 of the TEN-E Regulation establishes rules on the dedicated permit granting process and its duration, providing for:
    - a flexible two steps approach, characterised by a pre-application phase and a statutory permit granting phase, to be set in place for the permitting of PCIs and PMIs.
    - A maximum duration of 42 months for the procedure, which may be extended by national competent authorities, on a case-by-case basis, in 9 months when the procedure requires longer in exceptional circumstances.

ANNEX 7: IMPLEMENTATION REPORTS

I. IMPLEMENTATION REPORT ON THE TRANS-EUROPEAN NETWORKS FOR ENERGY REGULATION

The revised **Regulation** (EU/2022/869) **on Trans-European Networks for Energy** (TEN-E Regulation)[184] entered into force in June 2022. This revision aimed to fully align the scope of the TEN-E Regulation with the European Green Deal, to make Europe a climate neutral continent by 2050. Furthermore, in line with the evolution of the Union's infrastructure needs and its decarbonisation goals, sustainability became one of the essential requirements employed across the selection of all priority infrastructure projects. The TEN-E Regulation lays down rules for the timely development and interoperability of trans-European energy networks in order to achieve the energy policy objectives of the Treaty on the Functioning of the European Union (TFEU) to ensure the functioning of the internal energy market and security of supply in the Union, to promote energy efficiency and energy saving and the development of new and renewable forms of energy, and to promote the interconnection of energy networks.

1. AIM OF THE REPORT AND RESEARCH METHOD

The targeted amendment (revision) of the TEN-E Regulation under the European Grids Package, as announced by the Action Plan for Affordable Energy[185], aims to keep the above stated general objectives of the TEN-E Regulation and ensure that greater efficiency is achieved when planning and deploying energy infrastructure (electricity and hydrogen). To this end, the package aims to strengthen certain elements linked to infrastructure categories and network planning, cost-benefit sharing, permitting processes and infrastructure security and resilience. Given the targeted character of this revision and how soon it takes place after the entry into force of the TEN-E Regulation this "Implementation Report" focuses on the performance of the specific provisions introduced and revised as part of the 2022 TEN-E Regulation revision. The Implementation Report replaces a full evaluation which would only be expected as part of the review of the TEN-E Regulation due in 2027[186]. An evaluation was previously conducted between January 2019 and September 2020, in context of the 2022 TEN-E Regulation revision.[187]

The report, to the extent possible, addresses the effectiveness, efficiency and coherence of the TEN-E framework as in force since 2022, as well as its EU added value and relevance. The report provides an overview of the main outputs linked to the implementation of the new framework per

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[184] Regulation (EU) 2022/869 to the European Parliament and the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013; OJ L 152, 3.6.2022, p. 45) June 2022. Available here: Regulation - 2022/869 - EN - EUR-Lex

[185] Communication from the Commission to the European Parliament, the Council, the European Economic And Social Committee and the Committee of the Regions: Action Plan for Affordable Energy: Unlocking the true value of our Energy Union to secure affordable, efficient and clean energy for all Europeans. COM/2025/79 final

[186] See Article 22 of the TEN-E Regulation.

[187] European Commission: Directorate-General for Energy, ECORYS, Ramboll, REKK, Shepherd and Wedderburn, Akkermans, F., Le Den, X., Heidecke, L., Jansen, L., Juárez, V., Kácsor, E., Mezősi, A., Nigohosyan, D., Nguyen, N., Rodger, S., Selei, A., Takácsné Tóth, B., Møller Thomsen, S., Til, H. v.Yagafarova, A., *Support to the evaluation of Regulation (EU) No 347/2013 on guidelines for trans-European energy infrastructure – Final report*, Publications Office, 2021, https://data.europa.eu/doi/10.2833/154438

topic. Specifically, it assesses the extent to which these elements achieved the stated objectives of the framework, including their contribution to the European Green Deal and to reaching climate neutrality by 2050.

A desk-based legal and policy analysis has been conducted for the preparation of this Implementation Report. The Commission carried out this analysis using different information channels. In addition to the relevant legislative documents, the primary source of information was the Commission's experience in the implementation of the TEN-E Regulation, including the assessment process for the selection of projects of common interest (PCI) and projects of mutual interest (PMI), as well as the assessment and inclusion of energy infrastructure projects in the relevant Ten-Year Network Development Plan (TYNDP). It also considers Member States' and stakeholders experiences of implementing the provisions related to permitting introduced by the TEN-E Regulation, collected through a dedicated study as well as information collected in a draft interim report for the support study for the assessment of the framework on European Grids.

2. ANALYSIS

Update and Introduction of New Infrastructure Categories

The 2022 revision of the TEN-E Regulation introduced a number of important policy changes, primarily reflected in the introduction of I) **new and updated energy infrastructure categories** and II) a **reconfiguration of priority corridors and areas**. Projects with third countries, or PMIs, were included in the scope of the TEN-E Regulation. The eligibility for the status of PCI and PMI was brought in line with the **European Green Deal**. The 2022 TEN-E Regulation revision presented a paradigm shift away from fossil fuels, with natural gas infrastructure and oil pipelines removed as infrastructure categories eligible for priority status. New categories including hydrogen infrastructure, electrolysers and smart gas grids were added to the scope of the TEN-E Regulation, as per revised Article 4(3) and Annex II.

The 2022 revision also saw an update of the existing categories. The electricity infrastructure category was extended to offshore projects, both hybrids and radials. The carbon dioxide infrastructure category was expanded to allow for surface and injection facilities associated with permanent storage. The scope of the smart electricity grids infrastructure category was expanded (and criteria streamlined) to encourage development of more projects. Among the more substantial changes, its scope was expanded to investments in islands and island systems aimed to decrease their energy isolation, as well as to the projects which do not involve a physical common border. Moreover, it created further possibilities for grid operators to propose projects[188].

The revised TEN-E Regulation strengthened sustainability, in terms of the integration of renewable energy sources into the energy networks and the reduction of greenhouse gas emissions, as an overarching specific criterion to be used in the selection of priority infrastructure projects in all categories. This made the implementation of the sustainability criterion much stricter compared to the previous Regulation (EU/347/2013), where sustainability was not a mandatory criterion.

The first list of PCIs and PMIs, fully in line with the European Green Deal, entered into force in April 2024. This was also the first list in which all the selected projects were required to demonstrate fulfilment of the criteria of significant contribution to sustainability. Out of 301

[188] Under the TEN-E Regulation, this includes TSOs, TSOs and DSOs, or DSOs from at least two Member States under certain conditions. Under the previous Regulation (EU/347/2013), these needed to be TSOs and DSOs from at least two Member States.

candidate projects, 166 were selected as PCIs and PMIs. Over half (85) were electricity, offshore and smart electricity grid projects. For the first time, hydrogen and electrolyser projects (65) were included. The first PCI/PMI list also included 14 CO_2 network projects, with the goal to create a market for carbon capture and storage. No smart gas grid projects were included on the list. A call for application to project promoters to submit their projects was again opened in September 2024, initiating the second PCI/PMI process under the revised Regulation. In total, 340 candidate projects were submitted. Following the meeting in June 2025 of the decision-making body composed of Member States representatives at technical level, in July 2025, a draft second PCI/PMI list was sent to Agency for the Cooperation of Energy Regulators (ACER) for its opinion. In line with the TEN-E Regulation, the adoption of the final list is planned for November 2025. Additional information pertaining to the number of candidate and selected projects, per infrastructure category is presented in dedicated sections from 1.1 – 1.3.

Table 11: Number of selected projects per infrastructure category on the Union lists

Infrastructure category	**Fifth PCI list** *Per repealed Regulation (EU) 347/2013*	**First PCI/PMI list**	**Draft Second PCI/PMI list**
		Per TEN-E Regulation	
Electricity	67	80 (including 12 energy storage and 12 offshore projects)	94 (including 22 energy storage and 19 offshore projects)
Smart electricity grid	6	5	6
Gas	20	/	/
Hydrogen	/	48 (including 10 reception and 7 storage facilities)	85 (including 9 reception and 19 storage facilities)
Electrolysers	/	17	25
Smart gas grids	/	0	3
Oil	0	/	/
Carbon dioxide	6	14	17

Note: Number of projects was influenced by the changes and updates to infrastructure categories in the TEN-E Regulation, as well as the introduction of PMIs in addition to PCIs.
Source: European Commission

The TEN-E Regulation identifies energy infrastructure priorities, based on strategic geographical priority corridors (11) and Union-wide priority areas (3). These were reconfigured as part of the 2022 TEN-E Regulation revision and are further discussed in section 5.

2.2 Electricity and Smart Electricity Grids Infrastructure Categories

In the first PCI/PMI list which entered into force in April 2024, 80 electricity[189] and 5 smart electricity grids projects were selected as PCI/PMIs, following 93 and 6 project candidate applications, respectively. The number of candidate projects in the second PCI/PMI process remained the same for smart electricity grids (6), while for electricity grids it increased to 114. Electricity grid candidate projects included 46 interconnection projects, 14 internal lines[190], 30 electricity storage and 24 offshore projects.

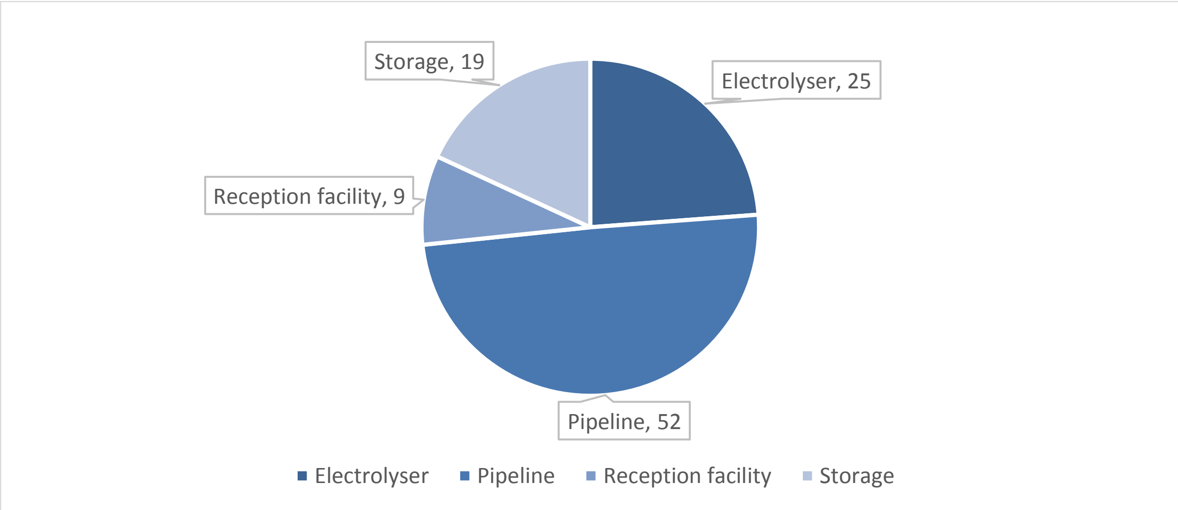
The number of projects included in the second draft PCI/PMI list is 94 for electricity and 6 for smart electricity grids. The offshore electricity infrastructure related provisions and their implementation is discussed in the dedicated chapter 4.

2.3 Hydrogen, Electrolyser and Smart Gas Grid Infrastructure Categories

In the first PCI/PMI list which entered into force in April 2024, 65 hydrogen and electrolyser PCI and PMI projects were selected, following 180 project candidate applications. The number of candidate projects increased to 199 in the second PCI/PMI process launched in September 2024. The number of projects included in the draft second PCI/PMI list is 105. The distribution of projects per hydrogen infrastructure category or electrolyser is presented in Figure 11.

In the first and second PCI/PMI processes, 19 out of 25 and 25 out of 68 submitted projects, respectively, had a capacity of more than 500 MW, reflecting a trend toward larger-scale developments. However, the majority of these —43 out of 68 in the second round— were focused on serving local demand without a cross-border dimension.

Figure 11: Distribution of projects, per Hydrogen infrastructure and Electrolyser categories, as included in the draft[191] second PCI/PMI list based on infrastructure type



[189] The infrastructure category includes offshore electricity projects, which covered in a dedicated section.
[190] Internal lines account for 23% of candidate electricity projects (when excluding offshore and storage electricity projects).
[191] The exact list of infrastructure projects and project data is conditional to the validation of the second Union PCI/PMI list. The statistics provided do not pre-empt the outcomes of the High-Level Decision-making Body meeting, nor the outcomes of the co-legislators' scrutiny of the delegated act defining the second Union PCI/PMI list.

Source: European Commission

Smart gas grids was introduced as a new infrastructure category in the revision of the TEN-E Regulation, with the intention to support investments smartening the gas grids so as to allow the integration of a plurality of low-carbon and particularly renewable gases such as biogas, biomethane, and hydrogen, in the gas network and help manage a resulting more complex system, building on innovative digital technologies. However, PCI applications were very limited. In the first PCI/PMI selection process, only 4 candidate projects applied, but none were able to meet the eligibility conditions defined in the TEN-E Regulation. In the second PCI/PMI selection process, 3 projects applied. They were all found eligible, but a with a reduced number of investments than those proposed due to eligibility requirements. All three projects were included on the draft second PCI/PMI list that was sent to ACER.

2.4 The Carbon Dioxide Infrastructure Category

The revised TEN-E Regulation broadened the scope of projects for which project promoters can apply to receive the PCI and PMI status. As previously explained, the change related to introduction of surface and injection facilities associated with permanent storage.

The first PCI/PMI list included 14 carbon capture and storage infrastructure projects, following 18 applications, while the second draft PCI/PMI list includes 17 projects after 19 applications. All the projects included in the draft second PCI/PMI list, aimed at carbon dioxide storage (14), included also surface and injection facilities.

Effectiveness:

Across the first and the second PCI/PMI selection process, there has been an increasing number of candidate and selected infrastructure projects. This trend was observed across most of the categories, including electricity, hydrogen, electrolysers and carbon dioxide infrastructure. Comparatively a lower number of candidate applications was received for the smart electricity grid category. The smart gas grid category has seen very few applications and has encountered significant issues as regards eligibility either of the applications in their entirety or of the assets included in the proposals. Still, taken together, these trends suggests that the TEN-E Regulation offers an attractive tool to identify and accelerate energy infrastructure projects with cross-border relevance.

In the electricity infrastructure category, internal lines represented 23 % of the total number of candidate projects (excluding offshore and storage projects). Given the fact that internal electricity lines are crucial for fully enabling cross-border flows, this raises some doubts on the effectiveness of the set threshold for cross-border impact (at 500 MW) for achieving the goals of the TEN-E Regulation, concretely to ensure market integration.

In the smart electricity grids infrastructure category, the majority of the projects concerned distribution networks, displaying certain limitation in the current design of the categories, as smart grid projects are also needed at the level of transmission networks.

Efficiency:

The design of the electricity infrastructure categories, as well as the smart grids category are mostly fit for purpose, allowing for efficient assessment, as demonstrated by high rates of eligibility among these projects.

With regard to the electrolyser infrastructure category, there has been a significant increase in candidate projects from first to the second PCI/PMI process (from 25 to 68). However, most electrolyser projects applying in the second PCI/PMI process were aimed to serve local demand.

The number of applications for the smart gas grids infrastructure category remains very low. While the eligibility rate improved, issues arose regarding the scope of some of the assets included for the candidate projects. Whilst the category is aimed at investment in digital equipment and digital installations with a view to smartening the natural gas network for the purpose of enabling the integration of renewable and low-carbon gases, candidate projects included upgrades of the natural gas network.
***Coherence**:*

The outcomes of the first and ongoing second PCI/PMI selection processes have proven to be mostly coherent with the objectives of the European Green Deal. Selected priority infrastructure projects comply with the sustainability requirement.

Two out of the three smart gas grid projects which applied under the second PCI/PMI selection process were aimed at facilitating certain levels of hydrogen blending. This raised consistency issues with the latest EU policy developments and as regards their interaction with Article 31 of the TEN-E Regulation (limited exemption concerning blending projects) and the risk or circumventing the conditions for allowing blending projects set in this Article.

3. Energy Infrastructure Financing Under the Connecting Europe Facility for Energy

Projects selected as PCIs and PMIs can automatically benefit from many advantages stemming from the TEN-E Regulation, including an accelerated permit granting and improved regulatory treatment. Projects on the list are eligible, under certain conditions, to apply for financial support for construction works and studies, under the **Connecting Europe Facility Energy (CEF-E) programme,** which was established in 2013 and continued under the current multiannual financial framework (2021-2027). CEF-E has a grant budget of EUR 5.84 billion for the period 2021-2027. The scope of eligible infrastructure financing under CEF was directly influenced by the updated and new infrastructure categories under the TEN-E Regulation. In addition, Article 18(2) of the revised TEN-E Regulation which determines the scope of infrastructure eligible to receive grants for works, was expanded to cover also hydro-pumped energy storage (under the electricity infrastructure category).

The first annual CEF-E call for PCI and PMI projects selected as part of the first PCI/PMI list under the revised TEN-E Regulation was launched in April 2024. It resulted in awarding EUR 1.25 billion in grants to 41 cross-border energy infrastructure projects in January 2025[192]. This is the largest amount awarded by any single CEF-E call to date. Overall, the funding was allocated for 5 works proposals (EUR 865 million) and for 36 studies (EUR 385 million). In April 2025, a new call for proposals for PCI and PMI projects under CEF-E was launched, with a budget of EUR 600 million.

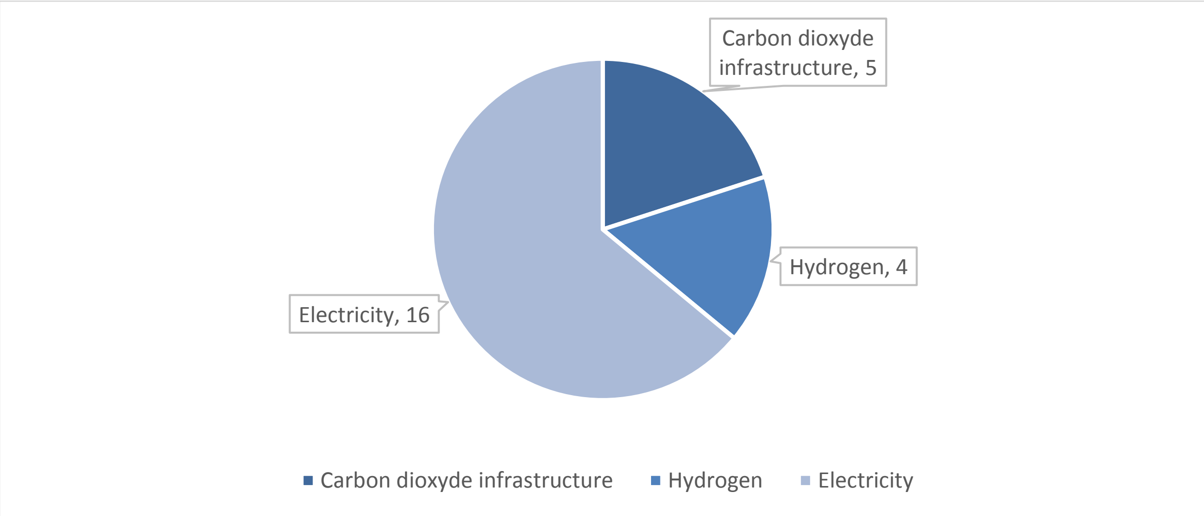
[192] Additional information, including the list of beneficiaries is available online: EU invests over €1.2 billion in cross-border infrastructure

4. Projects of Mutual Interest

The revised TEN-E Regulation introduced the PMI category for projects involving Member States and third countries. Among the 166 projects included in the first PCI/PMI list, 12 projects were PMIs (8 for electricity, 2 for hydrogen and 2 for carbon dioxide infrastructures). No PMIs were awarded grants funding following the 2024 CEF-E call.

The draft second PCI/PMI list included 25 projects, with the large majority being electricity infrastructure projects (16), as seen in Figure 12.

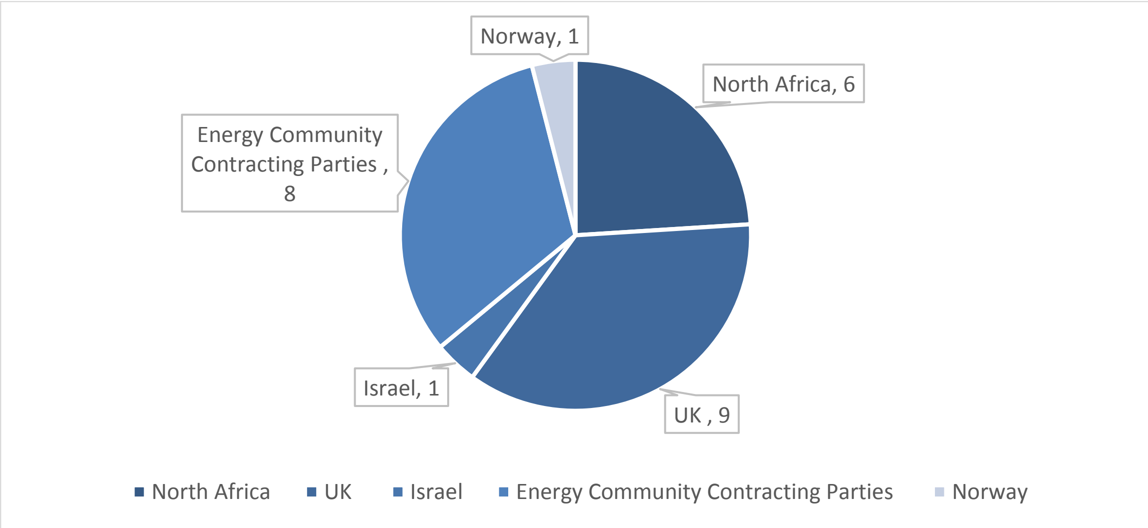
Figure 12: Distribution of PMIs in the draft second PCI/PMI list, per infrastructure category



Source: European Commission

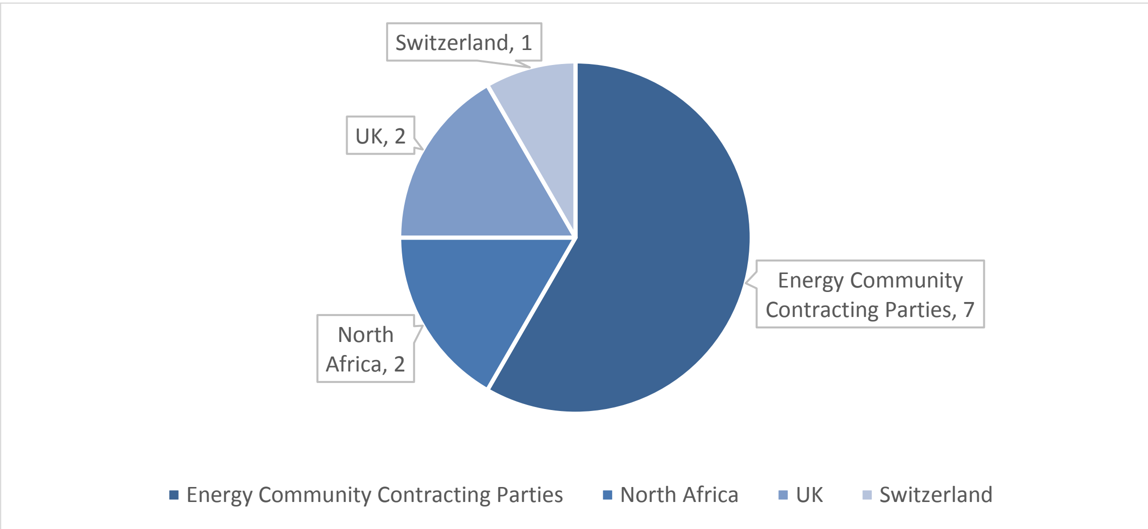
In addition to their contribution to achieving sustainability and climate neutrality, PMIs are required to comply with a number of criteria as laid out in Article 4(2) of the TEN-E Regulation. Notably, PMIs should demonstrate significant benefits at Union level, outweighing their cost within the Union. Between the first and second PCI/PMI selection process, the number of candidate PMI projects increased from 42 to 46. Among the 25 electricity projects which applied for the PMI status, in the second PCI/PMI selection process, most candidate projects submitted were with the UK (9), the Energy Community Contracting Parties (8) and Northern African countries (6) as seen in Figure 13. Most hydrogen PMI applications, were with the Energy Community Contracting Parties (7), followed by North African countries and the UK (2 each), as seen in Figure 14. Regarding carbon dioxide infrastructures, five projects applied for a PMI status in the second PCI/PMI process, a majority of which involved Norway (3), while one project involved Switzerland and one project the UK.

Figure 13: Distribution of electricity PMI candidate projects for the second Union list, per region



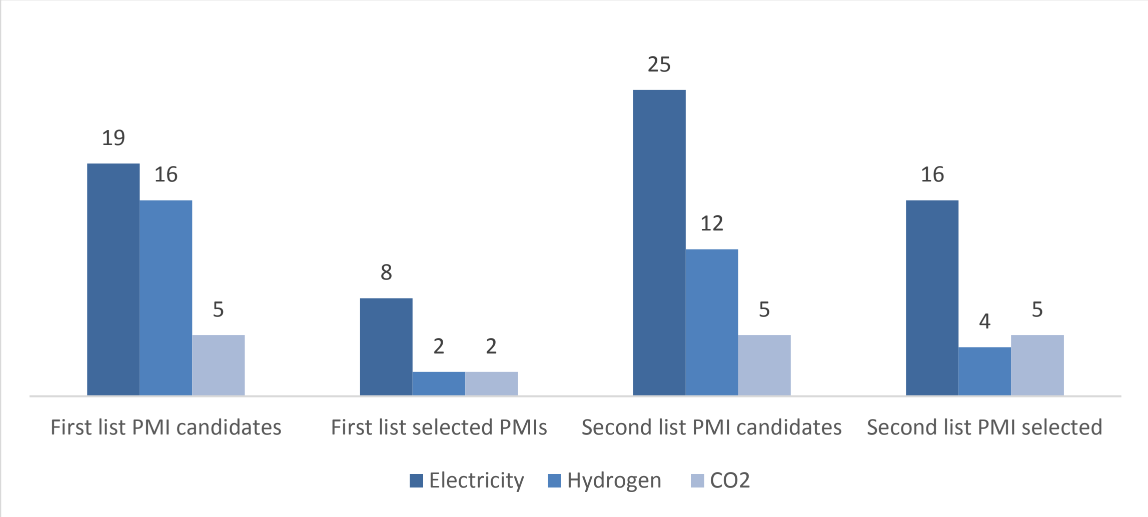
Source: European Commission

Figure 14: Distribution of hydrogen and electrolyser, PMI candidate projects for the second Union list, per region



Source: European Commission

Figure 15: Evolution of the number of PMI projects, per infrastructure category



Note: The categories of smart electricity grids and smart gas grids are not available for PMI status.
Source: European Commission

> ***Effectiveness**: Increasing the number of candidate PMIs shows that the introduction of this category of projects is in line with the growing interest in infrastructure projects with neighbouring countries, and brings environmental and market benefits for the EU.*
>
> ***Efficiency**: The high number of ineligible electricity and, particularly, hydrogen PMI candidates indicates that the proposed provisions are not fully efficient in setting a clear framework for PMIs. Concretely, the scope of the PMI category would deserve further clarification (some ineligible projects related to insufficiently clear project scope). The criterion requiring demonstration of significant benefits at Union level proved to be efficient in the project assessment, especially for projects under consideration. Projects with very low benefits for the Union have not passed the threshold for inclusion on the PCI/PMI list. Lastly, the PMI provisions have also led to some inefficiencies in the selection process as the assessment of PMI projects meeting the TEN-E Regulation objectives has proven to be resource intensive and burdensome for both project promoters and the Commission.*
>
> ***Coherence**: The inclusion of projects with third countries is coherent with the EU Neighbourhood Policy, and work in energy cooperation with third countries, linked also to their market liberalisation. Furthermore, it supports alignment with the EU policy framework especially with the Energy Community Contracting Parties, and countries involved in the accession process. However, the criterion requiring demonstration of significant benefits at Union level for PMIs, has led to non-inclusion of several projects with Energy Community Contracting Parties. Interconnections with the Energy Community Contracting Parties, despite low socio-economic benefits for the EU, are de facto directly impacting the electricity market of the Union (as well as EU's security of supply) due to the inclusion of the Energy Community Contracting Parties in the Continental Europe Synchronous Area. Furthermore, practical implementation of the PMI category showed some limits in terms of coherence with climate and energy goals, as in some cases it was difficult to assess how projects contribute (or would not hinder) the possibility of a given country to phase-out fossil fuels, or how the country concretely ensured market convergence and contributed to climate targets.*

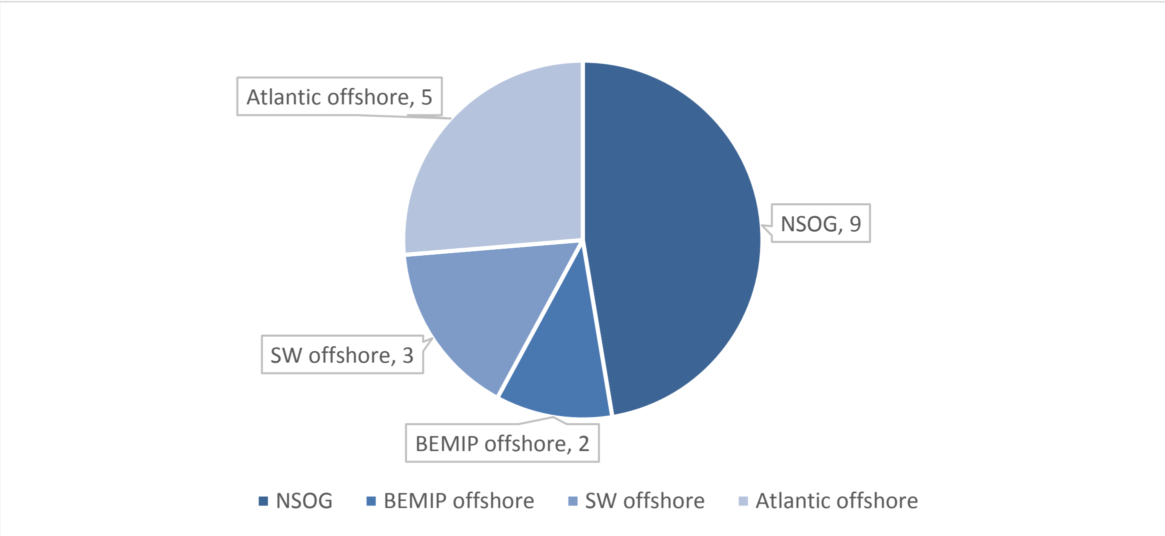
5. Offshore Renewable Energy

The revised TEN-E Regulation introduced new provisions to support the upscale of offshore renewable energy in the EU. This includes **five dedicated offshore priority corridors** around Europe's sea-basins (Annex I), with the possibility for offshore projects, including hybrids and radials, to be selected as PCI or PMI under the electricity infrastructure category (Annex II). Furthermore, **a specific chapter on offshore grids for renewable integration (**Chapter 5) was included, with provisions to support the coordinated long-term offshore grid planning (Article 14) and related cross-border cost sharing (Article 15).

5.1 Offshore Electricity Infrastructure Projects

In the first PCI/PMI list, out of 80 projects in the electricity infrastructure category, 12 were offshore grid projects, including 9 radial links and 3 hybrid projects. Amongst the different offshore grid priority corridors, the Northern Seas offshore grids (NSOG) priority corridor had the highest number of selected projects (with 6 projects). For other corridors, 2 projects were selected each, except for the South and East offshore grids (SE offshore), which had no projects submitted. Between the first and second PCI/PMI selection process under the revised TEN-E Regulation, the number of candidate projects increased from 13 to 24. 19 offshore electricity projects were included in the draft second PCI/PMI list, with the majority again being radial links (14) compared to hybrid projects (5). Most projects were selected again in the NSOG corridor (9), followed by Atlantic offshore grids (5), as shown in Figure 16.

Figure 16: Distribution of offshore grids projects included in the draft second PCI/PMI list per offshore grid corridor



Note: No applications in the SEE offshore corridor were received.
Source: European Commission

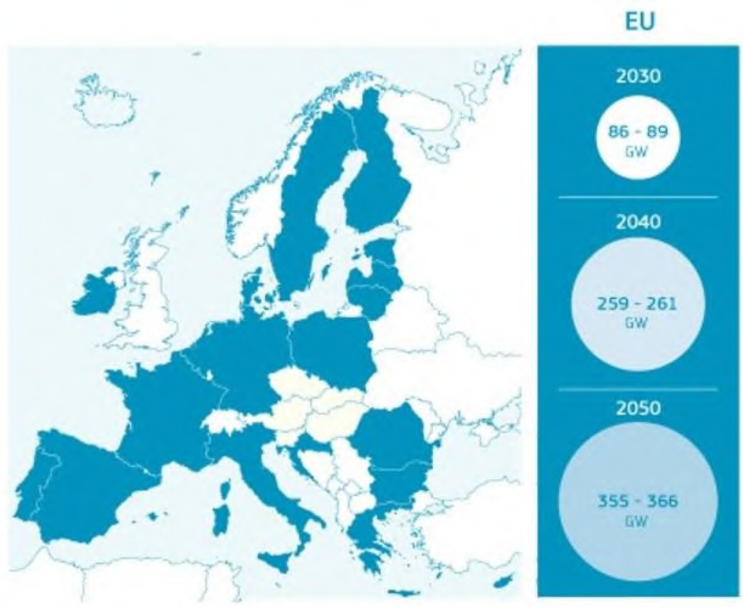
Effectiveness*: The increasing number of offshore electricity priority infrastructure projects indicates a positive trend and demonstrates the effectiveness of the framework for harnessing the potential of offshore renewable energy.*

Efficiency*: The offshore electricity infrastructure category efficiently enables the identification of cross-border energy infrastructure projects. However, the number of project proposals involving radial links has been much higher compared to hybrid projects, indicating that the full potential of the latter to efficiently unlock offshore energy resources across Member States and to enhance security of supply, market integration, and decarbonization by* *enabling interconnections between Member States alongside the simultaneous integration of offshore renewable energy has not been fully tapped, in the current framework.*

5.2 Offshore Grid Planning Provisions

In line with Article 14(1), Member States, with the support of the Commission, were tasked to agree, at regional level, on goals for offshore renewable generation to be deployed within each of the 5 sea basins by 2050, with intermediate steps in 2030 and 2040. The respective **non-binding agreements** were first adopted in January 2023 by Member States. As foreseen under Article 14(1), Member States had to update these regional agreements by December 2024. The ambition included in the updated agreements remained relatively stable, resulting in cumulative EU offshore goals of the following ranges[193]: 86-89 GW by 2030, 259-261 GW by 2040, and 356-366 GW by 2050.

Map 1: Member States updated regional non-binding agreements for offshore renewable generation



Source: European Commission

Furthermore, in line with Article 14(2), ENTSO-E was tasked to develop an Offshore network development plans (ONDPs) for each of the EU sea basins. These plans provide high-level information on the infrastructure that would be needed to achieve the goals of Member States. With the involvement of the relevant transmission system operators (TSOs), the national regulatory authorities (NRAs), the Member States and the Commission, ENTSO-E published the

[193] In some cases, the national goals are expressed as ranges, partially reflecting on-going national discussions and/or a degree of uncertainty associated with the level of future development of offshore renewable energy, especially within the 2040/2050 timeframes. As a result, the cumulative EU offshore goals have been expressed in ranges.

first ONDPs in January 2024. Those plans will be updated following the update of the non-binding agreements by Member States.

A third consecutive offshore related requirement, set out in Article 15(1), concerns the non-binding sea-basin cross-border cost-benefit sharing assessment for the development of the ONDPs, which ENTSO-E was required to present by June 2025. To support this process, the Commission developed guidance as foreseen under the TEN-E Regulation[194]. This included methodological elements for ENTSO-E's assessment at sea-basin level as well as additional considerations to facilitate investment for cross-border offshore grid and renewable projects. The results of ENTSO-E's assessment were presented to the TEN-E priority offshore corridors in a cross-regional meeting on 4 July 2025. The objective of both this guidance and cross-border cost-benefit sharing assessment at sea-basin level was to provide non-binding information to support Member States NRAs and TSOs to kick-start cost-sharing discussions for offshore projects.

Effectiveness*: The Member States regional non-binding agreements on goals for offshore renewable generation provided an important political signal and increased visibility for the sector. They also enabled the establishment of top-down planning at the sea-basin level within the context of the ONDPs. In turn, the ONDPs offered important information on sea-basin infrastructure needs and associated costs to achieve Member States' goals, facilitating some regional planning discussions on concrete projects. For example, the Offshore Transmission Coalition (OTC) in the North Sea is currently exploring regional planning for a set of projects. Additionally, the first non-binding sea-basin cross-border cost-benefit sharing assessment, performed by ENTSO-E, is expected to support such discussions; however, the relation between the process carried out by ENTSO-E on the TEN-E Regulation and the above-mentioned initiative of OTC remains to a certain extent unclear.*

Efficiency*: The Member States' non-binding goals and the ONDPs have been proven to be an important building block from which to start offshore planning. This ensures that needs are derived from Member States' objectives and builds on existing scenarios and modelling tools. Furthermore, the upcoming integration of ONDP products into the TYNDP 2026 will promote a more optimized and integrated approach to both offshore and onshore planning. Ultimately, this supports a more efficient approach to planning overall. However, these processes so far have not led to the identification and realisation of concrete cooperation projects.*

Coherence*: The TEN-E Regulation offshore planning provisions proved to provide a coherent support for offshore development in line with the EU offshore renewable energy policy, and notably the EU Offshore Strategy and the Communication on delivering on the offshore renewable energy ambitions.*

6. Reconfiguration of the priority corridors and areas

As previously explained, the TEN-E Regulation revision brought upon a reconfiguration of priority infrastructure corridors and areas.

Table 12: Distribution of projects per priority geographical infrastructure corridor and priority thematic area on the Union lists of PCIs and PMIs

[194] Accessible online: Guidance on collaborative investment frameworks for offshore energy projects - European Commission

	First PCI/PMI list	Draft second PCI/PMI list
	Per TEN-E Regulation	
Priority geographical corridors		
Electricity corridor		
North-South electricity interconnections in Western Europe - **NSI West Electricity**	**24**	**37**
North-South electricity interconnections in Central Eastern and South Eastern Europe - **NSI East Electricity**	**23**	**30**
Baltic Energy Market Interconnection Plan in electricity - **BEMIP Electricity**	**21**	**8**
Offshore grid corridors		
Northern Seas offshore grids - **NSOG**	**6**	**9**
Baltic Energy Market Interconnection Plan offshore grids - **BEMIP offshore**	**2**	**2**
South and West offshore grids - **SW offshore**	**2**	**3**
South and East offshore grids - **SE offshore**	**0**	**0**
Atlantic offshore grids	**2**	**5**
Corridors for Hydrogen and Electrolysers		
Hydrogen interconnections in Western Europe - **HI West**	**53**	**74**
Hydrogen interconnections in Central Eastern and South Eastern Europe - **HI East**	**9**	**21**
Baltic Energy Market Interconnection Plan in hydrogen - **BEMIP Hydrogen**	**3**	**15**
Priority Thematic Area		
Smart electricity grids	**5**	**6**
Cross-border carbon dioxide network	**14**	**17**
Smart gas grids	**0**	**3**

Note: the two PCI/PMI lists contain, by way of exception, two gas projects that aim to connect the isolated islands Cyprus and Malta, in line with the Article 24 of the TEN-E Regulation.
Source: European Commission

Effectiveness: *The selection of projects, along the reconfigured, priority infrastructure corridors and thematic areas delivered broadly on the goals, as set out in Annex I of the TEN-E Regulation. Multiple projects were selected across all the infrastructure corridors and groups, with exception of SE offshore.*

7. Reinforced Permitting Provisions

The revised TEN-E Regulation also reinforced permitting provisions, with the aim to accelerate the implementation of PCI and PMI projects. Still, as identified in the 2025 Study on national permit granting processes applicable to energy transmission infrastructure projects[195],

[195] Accessible online: Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest under Chapter III of Regulation (EU) 2022/869 - Publications Office of the EU. The study evaluated compliance with the provisions of Chapter III of

commissioned by the European Commission, there are discrepancies across Member States in the adoption of certain permitting provisions stemming from the TEN-E Regulation. Moreover, in line with the experience of the Commission in discussions concerning project implementation within the regional groups and the informal platform of national competent authorities in charge with permitting, a series of miss-conceptions and unclarities persist regarding the permitting provisions in the TEN-E Regulation, e.g. the nature and scope of the pre-application procedure, the nature of the 3.5 years deadline, the scope of the comprehensive decision and that of the early public consultation. If these discrepancies and need for clarifications are addressed, Member States could strengthen their respective permitting frameworks, enable timely delivery of critical energy infrastructure projects, and advance on the EU's energy transition and climate targets.

Table 13: Implementation of provisions introduced in Chapter III on Permit granting and public participation

Article reference	Summary of Member State implementation
Article 7(4) on *"dispute and judicial resolution procedures"*	**In terms of implementation, 7 Member States (MSs) are compliant, 11 MSs are partially compliant, while no measures were identified in 9 MSs.** In 7 MSs, PCI/PMIs automatically benefit from urgent judicial procedures; In 7 MSs, PCI/PMIs can benefit from the procedures if certain criteria are met; In 4 MSs the application of procedures is determined on case-by-case basis; In 9 MSs, no specific urgent judicial procedures exist in general or are not applicable to energy infrastructure projects.
Article 7(5) on *"streamlining environmental assessment procedures"*	**In 23 Member States, relevant measures to streamline environmental assessment procedures were identified.** In 14 MSs, rules for conducting an integrated environmental assessment are in place. Environmental Impact Assessment (EIA) has been linked with Strategic Environmental Assessment (SEA) in 3 MSs, while in 2 MSs, this has been done with the procedures required under the Habitats Directive and Birds Directive. All of these procedures are linked, in the case of 8 MSs. A number of additional supporting legislative measures have also been implemented by a number of MSs.

Note: Additional provisions on permitting were introduced as part of the TEN-E Regulation revision in Chapter III but were not covered by the study. These include. Article 8(6) on "designation of a point of contact for project belonging to an offshore grid corridor" and Articles 10(3) & 10(4) on "clarification on the start of the permitting process" and "use of existing studies".

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the revised TEN-E Regulation that produced legal obligations, including those introduced and amended in the revision.

Source: European Commission (2025). Study on national permit granting process applicable to energy transmission infrastructure projects with a focus on projects of common interest and projects of mutual interest under Chapter III of Regulation (EU) 2022/869

Effectiveness: *The amendments generally achieved their aim to increase the clarity and flexibility of procedures. Specifically, in what concerns the new provision on dispute resolution, impacts where significantly hampered by the fact that 9 Member States do not have such procedures under national law and projects only benefit automatically from the procedure in 7 Member States. The changes introduced to Article 10, improved clarity on the need to take into account pre-existing studies and assessments when evaluating permit applications but did not succeed in harmonising the understanding of what is the start of the permitting process across Member States, as confirmed by national authorities.*

Efficiency*: The provisions introduced did not significantly increase the efficiency of the permitting procedures as their average duration has even increased between 2023-2025*[196]*. Most Member States have complied with the obligation to streamline environmental assessments. However, these are still estimated to average at a duration of 20.6 months*[197]*. In what concerns the accelerated permitting of offshore projects through the designation of offshore single points of contact, exchanges with stakeholders indicate that the uptake of this provision has been limited so far with the processes relying on ad hoc coordination between relevant Member States, which does not accelerate procedures.*

Coherence*: At the time of its enactment, in 2013, the previous Regulation (EU/347/2013) established the first accelerated permit granting framework with a binding maximum duration, which was applicable only to PCIs and PMIs. Thus, when the revisions were tabled in 2021, the changes introduced were simply aimed at improving the accelerated procedure already in place (not amend it significantly). However, since then (and mainly in 2022 following the REPowerEU plan) new accelerated permitting frameworks for energy projects were established under the: Renewable Energy Directive, the Gases Directive and the Net Zero Industry Act. Due to these changes, when compared to renewable energy projects, certain* CO_2 *and hydrogen projects covered by the new provisions, PCIs and PMIs no longer benefit from the best and most urgent treatment. Since these projects are selected as being of European interest, this situation must be rectified by accelerating their treatment in permitting procedures.*

8. Strengthened Cross-Sectoral Infrastructure Planning Provisions

The revised TEN-E Regulation aimed at strengthening cross-sectoral infrastructure planning through several dedicated means.

It promoted the application of the energy efficiency first principle as part of the process of preparing the TYNDP. The ENTSOs were obliged to align their joint scenarios to be used for the Union-wide TYNDPs with the energy efficiency first principle and to take into account the latest available Commission scenarios, as well as, when relevant, the national energy and climate plans (Article 12(1)). Also, the ENTSOs were mandated to implement the energy efficiency first

[196] Collection of information and data on the implementation of the revised Environmental Impact Assessment (EIA) Directive (2011/92/EU) as amended by 2014/52/EU), final report, page 25.
[197] Accessible online: Monitoring of projects of common interest and of mutual interest - 2025 | www.acer.europa.eu

principle during the infrastructure gaps identification process (Article 13(1)), while regional groups had to consider it when establishing the regional lists of proposed PCI and PMIs.

Requirements for a more extensive consultation process with Member States, stakeholders identified in the TEN-E Regulation, and the European Scientific Advisory Board on Climate Change (ESABCC) were introduced, during the preparation of single sector draft methodologies for a harmonised energy system-wide cost-benefit analysis (CBA) (Article 11), joint scenarios to be used for the Union-wide TYNDPs (Article 12) and infrastructure gaps reports (Article 13).

The revised TEN-E Regulation mandated consistency between the single sector methodologies, for harmonised energy system-wide CBAs, performed respectively by the ENTSOs (Article 11(1)) and the Commission (Article 11(8)). Also, the Commission was given authority to approve joint scenarios to be used for the Union-wide TYNDPs (Article 12(6)), while the ACER was mandated to provide an opinion on its draft 12(5)[198]. Provisions on cross-sectorial planning were further strengthened with the Decarbonised Gases package in 2024, notably by the inclusion of hydrogen and ENNOH in the planning exercise.

8.1 Energy System Wide Cost-Benefit Analysis

As previously indicated, the Article 11 of the revised TEN-E Regulation outlined the need for the development of the consistent single sector methodologies and for a harmonised energy system-wide CBA at Union level for projects falling under different energy infrastructure categories. Pursuant to Article 11(1), ENTSO-E was tasked to draft the methodology for harmonised energy system-wide CBA for electricity, while ENTSOG, for gases and hydrogen until the ENNOH would be able to take over. In line Article 11(8), the Commission was tasked to draft methodologies for the harmonised energy system-wide CBAs for the following new or updated infrastructure categories: electrolysers, smart gas grids, smart electricity grids, CO2 networks and energy storage.

ENTSO-E and ENTSOG published and submitted for comments to Member States, the Commission and ACER, their draft single sector methodologies on 23 April 2023 and 30 June 2023, respectively. The ENTSOs performed extensive consultations envisaged by Articles 11(2) and 11(5), receiving also ACER's opinions on the two methodologies. The ENTSOs then submitted the revised methodologies to the Commission. Following its approval, the ENTSOs published their revised methodologies.

Pursuant to Article 11(8), on 7 October 2022 and, respectively, on 15 November 2022, the Commission published for consultation six single sector methodologies for harmonised energy system-wide CBAs. The final versions were published in May 2023. In addition to the five categories outlined above, the Commission also adopted a methodology for hydrogen, as a temporary instrument before ENTSOG's methodology entered into force.

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[198] The Commission's authority to approve the single sector draft methodologies for a harmonised energy system-wide CBA developed by the ENTSOs (Article 11(5)), as well as ACER's authority to provide an opinion on the draft (Article 11(3)) were already introduced with the previous Regulation (EU/347/2013).

Table 14: Overview of methodologies for a harmonised system-wide CBA published following the adoption of the revised TEN-E Regulation

Infrastructure categories as set out in Annex II	**Name of the document**	**Published:**
Concerning electricity, points (1)(a), (b), (d) and (f).	4th ENTSO-E Guideline for cost-benefit analysis of grid development projects[199]	April 2024
Concerning smart electricity grids, point (1)(e)	Harmonised system-wide cost-benefit analysis for candidate smart electricity projects[200]	May 2023
Concerning energy storage facilities, point (1)(c)	Harmonised system-wide cost-benefit analysis for candidate energy storage projects[201]	May 2023
Concerning smart gas grids, point (2)	Harmonised system-wide cost-benefit analysis for candidate smart gas grids projects[202]	May 2023
Concerning hydrogen, point (3)	ENTSO-G Methodology for Cost-Benefit Analyses of Hydrogen Infrastructure Project[203]	February 2025
Concerning hydrogen, point (3)	Harmonised system-wide cost-benefit analysis for candidate hydrogen projects[204] *(replaced by the 2023 CBA Methodology of ENTSO-G)*	May 2023
Concerning electrolyser facilities, point (4)	Harmonised system-wide cost-benefit analysis for electrolyser projects[205]	May 2023
Concerning carbon dioxide, point (5)	Harmonised system-wide cost-benefit analysis for candidate cross-border carbon dioxide network projects[206]	May 2023

Source: European Commission

Pursuant to Article 11(9), ACER was tasked to establish and publish a set of indicators and corresponding reference values for the comparison of unit investment costs of comparable projects of the energy infrastructure categories covered by the TEN-E Regulation, every three years. On 27 July 2023, ACER published the report, together with an energy infrastructure unit investment cost calculator, to facilitate future estimations of unit investment costs[207]. In line with Article 11(10), ENTSO-E and ENTSOG need to jointly submit to the Commission and ACER a consistent

[199] Accessible online: 4th ENTSO-E Guideline for cost-benefit analysis of grid development projects
[200] Accessible online: Harmonised system-wide cost-benefit analysis for candidate smart electricity projects
[201] Accessible online: Harmonised system-wide cost-benefit analysis for candidate energy storage projects
[202] Accessible online: Harmonised system-wide cost-benefit analysis for candidate smart gas grids projects
[203] Accessible online: Methodology for Cost-Benefit Analysis of Hydrogen Infrastructure Projects
[204] Accessible online: Harmonised system-wide cost-benefit analysis for candidate hydrogen projects
[205] Accessible online: Harmonised system-wide cost-benefit analysis for electrolyser projects
[206] Accessible online: Harmonised system-wide cost-benefit analysis for candidate cross-border carbon dioxide network projects
[207] Accessible online: ACER publishes a report on unit investment costs indicators and corresponding reference values of European energy infrastructure | www.acer.europa.eu

and progressively integrated model that will provide consistency between single sector methodologies based on common assumptions including electricity, natural gas and hydrogen transmission infrastructure as well as storage facilities, liquefied natural gas and electrolysers. Towards its fulfilment, the ENTSOs published their Interlinked Model (ILM) 2024 progress report on 7 May 2024[208], providing a dual assessment methodology for electricity and hydrogen. Based on the changes introduced by the Decarbonised Gases Package,[209] the final report will be published in October 2025, with a delay of some 4 months from the original goal in the TEN-E Regulation, caused by procedural matters.

Effectiveness*: The process for developing harmonised CBA methodologies has proven to be effective and led to development of infrastructure category specific, yet fairly consistent, methodologies.*

Efficiency*: Based on the Commission's experience, the technical and data limitations have been persisting obstacles to delivering robust CBA methodologies based on quantifiable and monetised indicators. The control mechanisms - ACER's opinion and the approval of the Commission - of the CBA methodologies for electricity and hydrogen have brought some improvements in the approach but have not been effective in addressing persisting shortcomings, e.g. in terms of better assessment of security of supply benefits. Also, the lengthy process for adopting opinions leads to efficiency losses.*

Coherence*: Related to the previous criterion, the coherence of methodologies with broader EU objectives was ensured to a certain extent by ACER and the Commission's opinion (with procedural limitations due to the applicable processes).*

8.2 Scenarios for the Ten-Year Network Development Plan

In line with the Article 12(1), ACER developed and published on 25 January 2023 the Framework Guidelines with criteria for a transparent, non-discriminatory and robust development of the joint scenarios to be developed by ENTSO-E and ENTSOG for their respective Union-wide TYNDPs[210], including the creation of the Stakeholder Reference Group for the scenarios' development. Following ACER's Framework Guidelines (Article 12(2)), and in line with the Article 12(3)), the ENTSOs developed the draft joint scenarios report[211] to be used for the TYNDP (joint scenarios report). In line with Article 12(4), the report was submitted for the opinions of ACER, Member States and the Commission, on 30 May 2024, some eight months after the date initially planned by the ENTSO's. The ESABCC, on its own initiative, provided an opinion on the draft joint scenarios report on 27 June 2024 pursuant to the second subparagraph of Article 12(4). Among Member States, Austria submitted written comments on 1 August 2024, indicating some misalignments of the joint scenarios with their latest national projections. On 30 September, ACER delivered its opinion[212] in which it underlined that the draft joint scenarios report was not

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[208] Accessible online: ENTSOG and ENTSO-E publish their joint electricity and hydrogen Interlinked Model 2024 progress report for public consultation

[209] Regulation (EU) 2024/1789 of the European Parliament and of the Council of 13 June 2024 on the internal markets for renewable gas, natural gas and hydrogen

[210] Accessible online: Framework Guidelines for the joint TYNDP scenarios to be developed by ENTSO for Electricity and ENTSO for Gas "TYNDP Scenarios Guidelines"

[211] Accessible online: ENTSO-E and ENTSOG TYNDP 2024 Draft Scenarios Report

[212] Accessible online: ACER Opinion 05-2024 on ENTSO-E and ENTSOG Scenarios for TYNDP 2024 and Guidelines

fully compliant with the Framework Guidelines they had issued in January 2023. ACER also provided recommendations on how to improve the report, as well as the future scenarios development processes starting with TYNDP 2026.

The Commission approved the joint scenarios report for the 2024 TYNDP on 14 January 2025. As highlighted in the decision, the joint scenarios could not comply fully with ACER's Framework Guidelines, because they were published only after the ENTSOs had already launched the scenario development process. Full compliance should be ensured for the following TYNDPs. The Commission's decision noted general alignment with the requirements introduced in the 2022 revision of the TEN-E Regulation. The draft joint scenarios have been widely consulted with stakeholders (including through Scenarios Stakeholder Reference Group, which met several times each month)[213] and broadly aligned with the Union's 2030 targets for energy and climate and its 2050 climate neutrality objectives. Furthermore, the energy efficiency first principle was considered through alignment with the energy efficiency targets, as well as latest available Commission scenarios (Fit-for-55 and REPowerEU scenarios) to the extent possible.

Following the Commission's approval, the report on joint scenarios was finalised by the ENTSOs. The update performed took into account updates to the carbon budget calculations, as per feedback provided by the ESABCC. The report was published on 29 January 2025.

***Effectiveness**: Assessing the effectiveness of the implementation of TEN-E Regulation provisions on the scenarios in terms of reaching the TEN-E Regulation objectives has certain limitations. Scenarios fully compliant with all the requirements of the TEN-E Regulation have not yet fully materialised due to the timeline of the scenarios' development. The application of the ACER Framework Guidelines will only have impacts in the TYNDP 2026 process, where one central scenario and two economic variants will be developed. The creation of the Stakeholder Reference Group has led to better involvement of stakeholders in the scenario building and more effective exchange of expertise and information. However, the implementation of the group's recommendations is still something to be followed up given the limited scope of adjustment to the scenario building process within the first two-year development cycle. Hence, involvement of stakeholders via the Scenarios Stakeholder Reference Group could be assessed as efficient in terms of meeting the TEN-E Regulation goals on stakeholder transparency.*

When it comes to consideration of the NECPs in the scenarios, the existing approach showed several shortcomings. The new TEN-E Regulation provisions have not proven, so far, to be effective in ensuring alignment with the NECPs while ensuring a timely development of the scenarios. Data collection for the scenarios remains a bottleneck and a timely, burdensome process, where ENTSOs struggle to get good quality data on time. The alignment with NECPs is also challenging because of the late delivery and quality of the plans. Concretely, NECPs are not always sufficiently detailed and do not encompass all the sectors (for instance the heating and cooling sector or electromobility). All these put a strain on the already tight development timeline of the scenarios.

The late delivery of the scenarios in the TYNDP cycle leads to delays of other TYNDP deliverables (needs assessment and projects' CBA). Furthermore, the ex-post control mechanisms (the ACER opinion and the Commission's approval) are not effective in ensuring any changes in the ongoing process because they come too late. Any adjustments to the

[213] Accessible online: ENTSOs TYNDP Scenarios: Stakeholder Reference Group (SRG)

scenarios could only be made in the following scenario development cycle. In particular, the Commission's decision has been an inadequate tool since a potential rejection of the scenarios would basically derail the completion of the TYNDP and the PCI/PMI process. The decision can only act as an emergency instrument to stop significantly incorrect scenarios without giving the Commission the right means to affect the scenario development. The formal and heavy Commission decision adoption process is also disproportionate for what can be achieved via this decision. In summary, the scenario building process seems not to be effective in meeting the TEN-E Regulation goals as it currently stands.

Efficiency*: While the objective of the 2022 TEN-E Regulation revision was, among others, to accelerate and streamline the scenario development process, this does not seem to have materialised. The 2024 scenarios were significantly delayed, as illustrated above. For the TYNDP 2026, based on the current timeline*[214]*, the scenarios are expected to be delayed by 4-6 months, which, inter alia, leads to issues not only for the PCI/PMI assessment process, but also for the Projects of Energy Community Interest process steered by the Energy Community Secretariat. As illustrated in the previous section, opinions come late in the process, which is not efficient from an administrative and cost perspective (FTEs spent on opinion drafting, even if they cannot substantially influence the process anymore).*

Coherence*: While the existing process of scenario building proved to be more coherent with EU climate and energy targets as under the previous Regulation (EU/347/2013) (inter alia by requiring stakeholder transparency and early involvement in the process, as well as the mandatory link with NECPs), there are still significant gaps due to data quality and availability, as well as the granularity of information available from NECPs.*

8.3 Infrastructure Gaps Identification and TYNDP Project Collection

Pursuant to the requirement of the Article 13(1), ENTSO-E and ENTSOG are mandated to publish the infrastructure gap reports under the TYNDP framework within six months following the publication of the joint scenarios reports (Article 12), and every two years thereafter. ENTSOG published for public consultation its draft Infrastructure Gaps Report[215] on 18 December 2024, while ENTSO-E published its own draft report[216] on 31 January 2025, some six months later than the targeted date set in ENTSO-E's work programme. Pursuant to Article 13(3), ACER published its opinions on the gaps reports on 27 May 2025 for ENTSOG's draft report and 26 May 2025 for ENTSO-E's draft report[217]. The assessment on the draft reports by the Commission, pursuant to Article 13(4) is currently ongoing and will result in opinions addressed to the ENTSOs, towards drafting their final Infrastructure Gap Reports.

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[214] State of play as of 28 July 2025.

[215] Accessible online: Hydrogen Infrastructure Gaps Identification Report | TYNDP 2024

[216] Accessible online: Opinion No 05/2025 of ACER of 27 May 2025 on ENTSOG Draft Hydrogen Infrastructure Gaps Identification Report

[217] Accessible online: Opinion No 04/2025 of ACER of 26 May 2025 on ENTSO-E's Draft TYNDP 2024 and on ENTSO-E's draft Infrastructure Gaps Report 2024

For the electricity sector there seem to be some discrepancies in terms of timeline, the interlink of the TYNDP project collection for the PCI/PMI assessment process and the Infrastructure Gaps Report.

Project collection for the 2026 TYNDP started in mid-April 2025 and lasted for one month, until mid-May 2025. During autumn 2025, there will be an opportunity to submit additional, non-mature projects (with project status "under consideration").[218]

Based on the 2026 TYNDP FAQ[219], the provisional list of projects admitted to the TYNDP 2026 is to be published in January 2026. The updated list is to be released for public consultation only in October 2026. CBA results as well as the draft infrastructure gaps identification (system needs study) are expected to be published for public consultation in Q4 2026.[220] At the same time, the 3rd PCI/PMI assessment process is set to start earlier, in early autumn 2026. There is thus a risk that projects which would not be accepted for the final TYNDP 2026 would apply for PCI/PMI process. At the time, such projects may still need to be assessed by the regional groups in the PCI/PMI selection process to ensure a non-discriminatory approach. This leads to inefficiencies and administrative burden. Also, the timeline as presented earlier raises questions on alignment of candidate projects with the needs identified, especially in light of the January 2026 provisional list.

Effectiveness*: Throughout the past two TYNDP processes (2024 and expected timeline for 2026 TYNDP), it has become evident that the Commission's opinion comes too late to affect the Infrastructure Gap Report. What is more, some of the elements of the opinion would come too late to be addressed even in the following TYNDP cycle e.g. the reference grid configuration. Hence, this ex-post control mechanism does not seem very effective, and the formal adoption procedure could be deemed as disproportionate to the impacts the opinion could bring. Furthermore, it has become evident that ACER and the Commission have little means to steer the gaps identification process in the desired direction and make it more relevant for the identification of the key projects for the Union. There is currently no mechanism to be applied in case projects do not fully meet addressed needs (this was also raised by ACER in their 2024 Infrastructure Market Monitoring Report).[221] Moreover, the timeline raises questions on whether the projects, if collected 1.5 year earlier than the results of the Infrastructure Gaps Report, are effectively addressing the needs, and if their alignment with the needs can be ensured. The publication of the final report a mere half a year before the collection for the next cycle starts also questions its effectiveness in terms of steering the project development for the next cycle (as half a year is not long enough to agree on new cross-border or even internal projects, not to mention inclusion in national network development plans, if necessary). As a consequence, under the current approach, the gaps identification report is more a self-standing deliverable than a sufficiently strong steer toward concrete project development.*

Efficiency*: The process and its timeline, as it stands currently, cannot ensure an efficient TYNDP and PCI/PMI selection process, as the TYNDP process selection results, the CBA results and the Infrastructure Gaps Report are not published early enough to directly feed into the PCI/PMI process (in terms of filtering project applications). This leads to inefficiencies in*

[218] Accessible online: Promoters corner | ENTSO-E TYNDP
[219] Accessible online: 250207_TYNDP2026_FAQ_ProjectPromoters_Final.pdf
[220] Accessible online: Entso-e | Explore the TYNDP
[221] Accessible online: Electricity infrastructure development to support a competitive and sustainable energy system | www.acer.europa.eu

the process, resulting in the assessment of projects which consequently may not be matching the infrastructure needs identified.

***Coherence**: The existing process proved not to be fully coherent with the climate and energy goals, due to timeline issues, but also due to the impossibility to take into account the Commission's opinion due to its very late delivery in the process (de facto after the decision of the Technical decision-making body on the draft PCI/PMI list).*

9. Cross-Border Cost Allocation

The TEN-E Regulation revision in 2022 has not materially changed the rules governing the cross-border cost-allocation framework compared to previous Regulation (EU/347/2013). However, in June 2023, ACER updated its recommendation on good practices for the treatment of the investment requests including Cross Border Cost Allocation (CBCA) requests, for PCIs, as foreseen under Article 16(11) of the Regulation. This updated recommendation provides further indications, for instance, regarding the recommended threshold when allocating costs and the treatment of uncertainty.

According to ACER's report on cross-border cost allocation decisions[222], the number of CBCA decisions for electricity PCI and PMI projects has decreased over time, while hydrogen projects have not received any CBCA decisions yet as projects are not mature enough to initiate an investment request including a CBCA or are not yet captured by the regulated regime. For electricity PCI and PMIs, 14 CBCA decisions were granted over the period 2014-2019 (June), while only 5 CBCA decisions were issued between (June) 2019 and 2024.

In recent years, there have been very few new CBCA decisions. Because of this, only a small number of projects on the latest PCI/PMI list have received a CBCA decision (either a new CBCA or a CBCA carried over from previous lists). Out of the 80 projects on the first PCI/PMI Union list, only 19 are covered by CBCA decisions, and just 2 of those are new projects.

Additionally, only a limited number of CBCA decisions include a transfer of costs across borders/ to non-hosting countries (3 out of 50 CBCA decisions for the period 2014-2024), all of which were in the gas sector so not relevant any more under the revised TEN-E Regulation.

Lastly, there is a strong link between the establishment of a CBCA and the CEF application. The project promoter(s) of all 50 investment requests expressed an intention to apply for CEF funding for works.

***Effectiveness:** The current CBCA provisions have facilitated the allocation of investment costs for PCI/PMIs in the gas and electricity sectors, primarily to support CEF applications for works. Within this framework, the TEN-E Regulation has effectively ensured that projects submitting CEF funding applications are based on well-founded investment requests and demonstrate sufficient maturity. However, there have been very few instances of involvement by non-hosting countries in CBCA decisions, and none in the electricity sector. Provisions have therefore had limited effectiveness in triggering additional investments from non-hosting countries that may benefit from the projects.*

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222 Accessible online: [ACER CBCA Report]

Efficiency: *The existing CBCA framework has enabled the allocation of CEF grants, helping to close the financing gap for some PCI/PMI projects, and has been relatively efficient compared to the resources required to establish such CBCAs. However, its efficiency has been relatively limited when considering its ability to trigger contributions from across borders and, thus, truly unlocking financing opportunities outside of Union grants.*

Coherence: *These provisions proved to be coherent with broader EU energy policy objectives, as they aim to facilitate the implementation of regulated cross-border energy infrastructure projects, thereby increasing interconnectivity between Member States and promoting electrification, for example, by unlocking the offshore renewable energy potential.*

10. Conclusions

In terms of coherence, the revision of the TEN-E Regulation in 2022 brought its scope in line with the objectives of the European Green Deal and with achieving climate neutrality by 2050. Its implementation provided evidence of the need for further improvements, namely when it comes to scenario development, infrastructure needs identification and consequent TYNDP, PCI/PMI project selection and assessment, as well as CBCA and permitting frameworks.

The first and the second PCI/PMI lists reflected the substantial policy changes made as part of 2022 TEN-E Regulation revision. Fossil fuel infrastructure stopped being eligible to benefit from the TEN-E policy framework. However, there is a risk associated with the smart gas grids project category with regard to possible indirect support of natural gas infrastructure, as shown in the second PCI/PMI selection process. The introduction of hydrogen and electrolyser infrastructure categories was very effective, in the sense that it led to a significant number of (successful) candidate projects, which also substantially increased from first to second PCI and PMI selection process. It remains to be seen how many of these projects will reach implementation stage. Moreover, many of the applied electrolyser projects were rather limited in size, raising questions about their added value, in terms of cross-border impact. In the electricity infrastructure category, there were also a significant number of candidate projects. The scope of the category was expanded to accommodate offshore infrastructure needs of Member States. However, the number of the proposed radial links compared to hybrid projects was noticeably larger, despite the latter's higher potential to, inter alia, efficiently unlock offshore energy resources across Member States. It is also visible that the number of internal electricity (onshore) lines remains limited compared to interconnections. On the other hand, the revision in the scope of smart electricity grids infrastructure category, and the introduction of new category for smart gas grids projects, did not bring about the intended uptake of projects falling under their scope.

In the two PCI/PMI selections processes, a growing interest in the infrastructure projects with third-country networks was observed. While it supports the alignment of the EU policy framework with the Energy Community (and especially EU accession) countries, and despite the impact these countries have on the internal EU energy market and security of supply due to existing interconnections, the current framework only considers benefits for the EU, resulting in some candidate PMIs with the Energy Community Contracting Parties not succeeding in the selection procedure, although they might contribute significantly to the EU's policy objectives.

The offshore grid planning provisions resulted in the adoption of non-binding goals and the ONDPs, which are important building blocks from which to start offshore planning. The upcoming integration of the ONDPs into the TYNDP 2026 will promote an even more efficient approach to planning overall. However, these processes so far have not led to the identification and realisation of concrete cooperation projects.

The permitting amendments introduced by the TEN-E Regulation revision in 2022 generally achieved their intended goal to increase the clarity and flexibility of procedures. Still, further improvements could be made to support the acceleration of procedures, contributing to the process's overall efficiency.

The provisions on cross-sectoral infrastructure planning were also subject to substantial revisions. While the harmonised CBA methodologies were delivered, and proven effective, technical and data limitations in their development influenced their robustness. The scenario development process, as it stands now, is faced with multiple drawbacks driven largely by delays and, hence, not fully effective in meeting the TEN-E Regulation goals. Similar issues hamper the gaps identification process. In addition, the Commission and ACER have little means to steer the process towards identification of the key projects for the Union. Moreover, there is no mechanism to be used in case the projects proposed do not fully meet the addressed needs.

With regard to the cross-border cost allocation, the TEN-E Regulation provisions have efficiently and effectively facilitated the allocation of investment costs for PCI/PMIs in the electricity (and in the past in the gas) sector, primarily to support CEF applications for works. However, there have been very few instances of involvement of non-hosting countries in CBCA decisions, and none in the electricity sector. Provisions have therefore had limited effectiveness in triggering additional investments from non-hosting countries that may otherwise significantly benefit from the projects.

II. IMPLEMENTATION REPORT ON THE RENEWABLE ENERGY DIRECTIVE LEGAL FRAMEWORK REGULATING PERMIT-GRANTING

The report focuses on the implementation to date of the legal framework regulating the permit-granting procedure to build, repower and operate renewable energy' plants and their related infrastructure (hereinafter: "permitting"), as set out in Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources[223] (hereinafter: "RED"). The importance of permitting for RES and the barriers it faces were already identified in Directive 2001/77/EC[224] of the European Parliament and of the Council, which required Member States to evaluate the permit-granting procedures in order to reduce the regulatory and non-regulatory barriers to the production of renewable electricity. Directive 2009/28/EC[225] of the European Parliament and of the Council introduced requirements to simplify the administrative procedures for renewable energy developers, whereas Directive (EU) 2018/2001 of the European Parliament and of the Council

[223] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast); OJ L 328 21.12.2018, p. 82.

[224] Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market; OJ L 283, 27.10.2001, pp. 33–40.

[225] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC (Text with EEA relevance), OJ L 140, 5.6.2009, pp. 16–62.

strengthens these requirements and introduces a permitting deadline for the first time (transposition by June 2021).

Following the Russian aggression against Ukraine and the adoption of REPowerEU, which highlighted the need for more and faster RES deployment in order to reduce dependency on Russian gas, Council Regulation (EU) 2022/2577 (the 'Emergency Regulation') laying down a framework to accelerate the deployment of renewable energy[226] and entered into force in December 2022. Its provisions were applicable for 18 months from this date. Application of certain of its provisions, alongside minor amendments, was extended until June 2025 by Council Regulation (EU) 2024/223[227] The extension was effectuated based on the findings of the Commission's Report of 28 November 2023 on the review of Council Regulation (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy. In the Report, the Commission found that the conditions for the prolongation of the validity of Regulation (EU) 2022/2577 were met and proposed to prolong selected measures that had the greatest potential for the acceleration of the deployment of renewables, which were not included in Directive (EU) 2018/2001, and which appear to bring about an important acceleration in the permit-granting process of renewable energy and for related grid infrastructure projects or which have the significant potential to do so.

In parallel, RED was amended by Directive (EU) 2023/2413 (hereinafter: 'the revised RED'),[228] which introduced an enabling framework to accelerate the deployment of renewable energy projects by simplifying and streamlining their permit-granting procedures, introducing new elements related to spatial planning and made permanent some important elements introduced by the Emergency Regulation. The deadline for Member States to transpose the planning and permitting-related provisions of this Directive was set mostly by July 2024, but also by May 2025 (Articles 15b and 15c). Directive 2018/2001 as amended by the revised RED and Council Regulation 2022/2577 amended by Council Regulation 2024/223 were introduced to accelerate the permit-granting procedure to build, repower and operate renewable energy' plants and their related infrastructure.

The targeted amendment (revision) of the RED under the European Grids Package, as announced by the Action Plan for Affordable Energy, aims to ensure that greater and faster deployment for RES is achieved as well as setting permitting rules for storage and recharging station assets that facilitate the integration of renewables.

In view of the recent last revision of the RED and its recent transposition deadlines, the Commission opted for an "Implementation Report", focused on the performance of the specific

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[226] Council Regulation (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy; OJ L 335 29.12.2022, p. 36.

[227] Council Regulation (EU) 2024/223 of 22 December 2023 amending Regulation (EU) 2022/2577 laying down a framework to accelerate the deployment of renewable energy; OJ L, 2024/223, 10.1.2024.

[228] Directive (EU) 2023/2413 of the European Parliament and of the Council of 18 October 2023 amending Directive (EU) 2018/2001, Regulation (EU) 2018/1999 and Directive 98/70/EC as regards the promotion of energy from renewable sources, and repealing Council Directive (EU) 2015/65; OJ L, 2023/2413, 31.10.2023.

provisions under the permitting-related provision of the revised RED to address the effectiveness of the existing permitting rules as well as their EU added value and relevance. The report provides an overview of the main outputs, linked to the implementation of the new framework, per topic. Specifically, it assesses in a retrospective manner the extent to which these elements have performed so far in achieving its stated objective of contribution to the European Green Deal and reaching climate neutrality by 2050.

1. METHODOLOGY AND DATA AVAILABILITY

1.2. General remarks

In general, it is substantiated that a comprehensive application of the EU framework for permitting brings an acceleration in terms of renewable energy deployment. However, the following elements should be considered:

- the permitting procedures of renewable energy plants and their related infrastructure vary significantly from one Member State to another, with country-specific national solutions coupled or intertwined with the obligations stemming from other EU or national legal bases. It is relevant, in this respect, to point out that, as the main EU permitting requirements are set in a Directive (the revised RED), Member States have a certain flexibility as to how they transpose its provisions into their national legal order.
- factors other than permitting can delay or halt RES projects, including the lack of grid capacity, cost and investment issues, demand, supply chain issues, etc.
- as per the ongoing study “Monitoring progress of measures to streamline permit-granting procedures under revised RED and Emergency Regulation and development of permitting-related KPIs”, and its First Interim Report received by the Commission in July 2025, many Member States do not collect the data on renewable energy permitting procedures (average duration, reasons for delays etc.) being initiated and/or concluded, and there is no common European format of such data or principles of their collection[229]. While progress has been made in some Member States on specific aspects, the monitoring of data remains fragmented, Thus, it is not always possible to directly link an increase of RES installed capacity in a Member States with the implementation of the EU rules on permitting.[230]

The Emergency Regulation has ceased to be applicable in its entirety since 30 June 2025. Nevertheless, a mock-up matrix linking the overarching topics with the specific provisions of both the revised RED and the Emergency Regulation is presented in this Report. A high-level summary of the revised RED permitting provisions is also set out.

To facilitate the assessment of their implementation, this Report groups the renewable energy permitting provisions in 3 overarching clusters, which reflect the major changes in the current

[229] The overview of the state of play of the RES permitting data collection in individual Member States is provided in the following section.
[230] Especially given that a successfully concluded permitting process of the renewable energy plant would be reflected only in the future statistics on e.g. installed RES capacity, which, moreover, are not always available at the same breakdown of details across all Member States.

permitting-granting framework. These are the Overriding Public Interest ("OPI"), the Single Contact Point[231] and the technology-related rules.

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2. ANALYSIS

2.1 Overview of the legal basis

The provisions of the revised RED with a July 2024 transposition deadline constitute a structured EU legal basis for the permit-granting procedures to build, repower and operate Renewable Energy Sources' plants and their related infrastructure. The scope of each of the Article is the following:

- Article 16: Organisation and main principles of the permit-granting procedure
  - Criteria for permitting process duration and validity of applications.
  - Streamlining of administrative processes.
  - Designation of single contact points.
  - Provision of adequate resources to competent authorities and reskilling of staff.
  - Digitalisation of permit-granting procedures (by 21 November 2025).
  - Public availability of decisions
- Article 16b: Permit-granting outside renewable acceleration areas ("RAAs")
  - Permitting timelines: <2 years, but <3 years for offshore, and <1 year for repowering, <2 years for offshore repowering.
  - All relevant environmental assessments for a renewables project to be rolled into one single procedure.
  - The killing or disturbance of species protected under the Birds & Habitats Directives must not be considered 'deliberate' where a project has followed all necessary mitigation measures.
- Article 16c: Permit-granting for repowering
  - Permitting timelines: <3 months for grid connections.
  - Screening limited to extension of existing projects.
  - Exemptions available for solar installations from screening and environmental assessments when no additional space is required compared to the original project.
- Article 16d: Permit-granting for solar installations on artificial structures
  - Permitting timelines: <3 months for solar equipment and co-located storage with possibility for applying exemptions, and <1 month for solar equipment with capacity of 100 kW or less.
  - Positive silence for solar equipment with capacity of 100 kW or less.
  - Exemptions available from screening and environmental assessments.

[231] Which existed already in the Directive (EU)2018/2001 but in simpler form.

- Article 16e: Permit-granting procedure for heat pumps
  - Permitting timelines: <1 month above 50 MW, but <3 months for ground source heat pumps, <2 weeks for connections to the grid for lower capacity MW/self-consumers).
- Article 16f: Presumption of overriding public interest (OPI)
  - Permitting, planning, construction and operation of renewable plants must be presumed to be in the OPI for the purpose of the application of certain exemptions regulated in certain environmental directives.

As mentioned already, some RES permitting provisions were already introduced by the Emergency Regulation, which was amended one time and ceased to apply in its entirety on 30 June 2025. The matrix of the revised RED and the Emergency Regulation provisions with the overarching topics' clusters could be visualised as follows:

Table 15: Permitting overarching topics EU legal basis:[232]

Overarching topic	Detailed description	Art. ER	Prolongation ER	Art. RED
Overriding public interest (OPI)	Several aspects of renewable energy projects are OPI, namely with respect to conservation of natural habitats and wild fauna, water policy, conservation of wild birds	3(1)	Prolonged until June 2025	16f with adjustments, namely, to duly justify in case this article is not applied
	Construction and operation of plants and related infrastructure which are OPI are given priority when balancing legal interests beyond environmental matters	3(2)	Prolonged until June 2025 with small changes	-
	Simplification of compensatory measures	Art. 3a	Introduced in 2023and in force until June 2025)	-
One Stop Shop (OSS)	One-stop-shop (Single Contact Point) and digitalisation	-	-	16(3)
Technology-specific provisions, including repowering	Small Solar up to 50 kW, sometimes lowered to 10.8 kW; permits to be granted within maximum 3 months	4	-	16d with adjustments, namely an increase of the limit to 100 kW
	Repower existing RES facilities, permits to be granted within 6 months	5(1)	Prolonged until June 2025, with small changes	-
	Repower existing RES facilities, with capacity increase below 15% permits to be granted within 3 months	5(2-5)	Prolonged until June 2025	16c with small adjustments
	Exemption from environmental impact assessment	6	Prolonged until June 2025	-
	Permit-granting process for heat pumps	7		16e with small adjustments
	Timeline exclusions	8	Prolonged until June 2025	-

[232] First Interim Report "Monitoring progress of measures to streamline permit-granting procedures under revised RED and Emergency Regulation and development of permitting-related KPIs", July 2025.

Overarching topic	Detailed description	Art. ER	Prolongation ER	Art. RED
	Specific deadlines for RE projects outside RAAs	-	-	16b

This Report replicates the breakdown into overarching topics presented above.

A targeted consultation of the selected stakeholders incl. business associations under the ongoing study "Monitoring progress of measures to streamline permit-granting procedures under revised RED and Emergency Regulation and development of permitting-related KPIs" revealed that when asked 'if the current regulatory framework decreased the duration of the permitting process' 39% of the respondents disagreed, while 37% agreed that that timelines are shorter. This suggests that statutory deadline provisions are beginning to take effect in some jurisdictions, yet implementation remains patchy and highly context dependent.

The same split views were given to the question 'Has the current regulatory framework increased the approval rate of permit applications?', with 35% of respondents reporting higher approval rates, 38% seeing no improvement, and 10% being neutral. Follow-up comments highlight initial improvements related to simplified environmental screenings are already in place, but little change to other parts of the permitting process. Lastly, the question 'Has the current regulatory framework enabled the faster deployment of renewable energy while reducing the workload for public authorities?' provoked the most scepticism, with only 25% of respondents answering 'yes' and 52% disagreeing. Both respondents and interviewed stakeholders cited staffing shortages and underdeveloped digital workflows as the main reasons why the expected reduction in workload has yet to materialise.

Stakeholders' input was also gathered in the Implementation Dialogue with Commissioner Jørgensen on permitting for renewable energy projects and related infrastructures, held on 11 June 2025. The discussions therein highlighted a consensus on the necessity to intensify efforts to implement current EU legislation, in particular the revised RED, and to further simplify permitting by reducing the regulatory burden, including by introducing exemptions to environmental legislation and for small-scale projects. There was a call on the Commission to further foster the exchange of best practices among Member States. Participants underlined the need to support permitting authorities with more resources and better skills, particularly at local level. The need for further simplifying procedures (especially for small-scale projects, storage and repowering), extending the overriding public interest principle, targeted exemptions from specific EU legislation, accelerating the digitalisation of permitting processes and improving data availability was also brought to the attention of the Commission.

2.2 Overriding Public Interest (OPI)

Article 16f of the revised RED requires Member States to set a rebuttable presumption that renewable energy installations, their related infrastructure and storage assets are in the overriding public interest and serving public health and safety when balancing legal interests in individual cases vis-à-vis certain EU environmental legislation, namely the Habitats Directive,[233] the Water Framework Directive[234] and the Birds Directive.[235] Member States may restrict the application of the OPI provisions to certain parts of their territory, to certain types of technology or to projects with certain technical characteristics. The Emergency Regulation, which expired in July 2025, also allowed Member States to "give priority" to RES installations that were recognised as being of OPI when balancing legal interests in the individual case beyond environmental matters.

As of June 2025, 9 Member States have provided information and declared full transposition with regards Article 16f, 5 Member States have declared partial transposition, and the remaining 10 Member States have not transposed and/or have not provided relevant information. Regarding 3 Member States, the transposition of Article 16f was not analysed due to the late submission of the required measures

A Member State which took advantage of the OPI concept enshrined in the Emergency Regulation already from December 2022 is Germany. It has achieved substantial integration of the OPI principle, not only limited to permitting for renewable energy installations but also enhancing permitting efficiency by recalibrating how environmental and other concerns are weighed in decision-making processes. The Federal Ministry for Economic Affairs and Climate Action (BMWK) has provided clear guidance to align regional permitting authorities with national and EU legislation, addressing uncertainties and questions from federal authorities. This consistent support has empowered authorities to implement relevant provisions with greater confidence. Judicial reinforcement has been equally important, with multiple court decisions upholding the precedence of OPI for renewable energy projects.[236]

This approach constituted a substantial pillar in accelerating the RES permitting process in Germany together with strong political commitment. In 2024, renewable energy generation capacity installed in Germany increased by 19.6 GW. This is double compared to 2022 and confirms the positive trend of 2023 (+18.6 GW). This is mainly thanks to additional solar capacity.[237] Depending on the source, granted permits for onshore wind reached 14 GW[238] or 15 GW[239] in 2024, meaning that permitted onshore wind capacity per year more than tripled

[233] Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora; OJ L 206, 22.7.1992, pp. 7–50.

[234] Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy; OJ L 327, 22.12.2000, pp. 1–73.

[235] Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds (Codified version); OJ L 20, 26.1.2010, pp. 7–25.

[236] Notable examples include the Federal Constitutional Court's recognition of EEG §2 in balancing wind energy development with forest protection (BVerfG, 27.09.2022 - 1 BvR 2661/21) and the application of this principle in heritage protection contexts by regional courts (OVG Greifswald, 07.02.2023 - 5 K 171/22).

[237] Data retrieved from: Bundesnetzagentur - Erneuerbare Energien

[238] Status des Windenergieausbaus an Land im Jahr 2024

[239] Bundesnetzagentur - Erneuerbare Energien

compared to 2022. This positive trend was confirmed in the first half of 2025, which set a new record with 7.8 GW of wind energy capacity permitted.[240]

For many Member States, the OPI concept has been comprehensively implemented only in relation to the revised RED transposition (not in relation to the Emergency Regulation), as it required amendments to sectoral pieces of legislation. Given the transposition deadline expired only in July 2024, it is still too early to establish a correlation of its application with the annual RES deployment rates. However, certain positive trends seem to be emerging in some Member States.[241]

At the same time however, research and stakeholders' feedback have revealed issues and confusion in many cases with regards to the implementation of this provision. In some Member States, implementation is hindered due to the stringent conditions under which it applies or due to persistent veto powers, especially from cultural heritage authorities. There are also cases where Member States continue to treat renewable energy projects as ordinary infrastructure, despite the Regulation's direct applicability and the Directive's expired transposition deadline, an approach that significantly weakens the intended effect of OPI.

2.3 Single Contact Point

According to Article 16(3) of the revised RED, Member States are required to set up one or more contact points which shall guide and facilitate the applicant during the entire administrative permit-application and permit-granting procedure. The applicant shall not be required to contact more than one contact point during the entire procedure, hence the concept of "the One Stop Shop". It shall provide the applicant with all necessary information and involve other authorities, were appropriate. It also has to keep track of the deadlines set out in the revised RED. According to Article 16(4), the contact point shall make available a manual of procedures for developers of renewable energy plants and shall provide that information online. This requirement for a manual of procedures builds on an obligation that already existed in the RED.

While it is difficult to quantify the impact of the Single contact point on duration of the permitting procedure or even more, on Member States deployment rate of renewable energy, its facilitating role shall not be underestimated, especially towards market participants with less expertise such as self-consumers, renewable energy communities or SMEs.

As of June 2025, Article 16(3) is declared as fully transposed by 4 Member States but only partially transposed by 13 MS. The remaining 7 have not transposed the provision or have not provided relevant information. This will be assessed by the Commission. Moreover, 7 Member States have declared full transposition of Article 16(4), while 7 declared partial transposition and 10 MS have either failed to transpose it so far or have not provided any relevant document.

[240] Marburg-Biedenkopf: Boom bei neuen Windrädern?

[241] First Interim Report "Monitoring progress of measures to streamline permit-granting procedures under revised RED and Emergency Regulation and development of permitting-related KPIs", July 2025.

Regarding the latter, 3 Member States were not analysed due to the late submission of the required measures.

The state-of-art example in this respect is Denmark, which has a well-established concept of a Single Contact Point for offshore wind projects, where the Danish Energy Agency has been the single focal point throughout the whole development process, liaising with different involved stakeholders.[242] The Agency has been expanding its services in this respect, assuming also the revised RED-compliant role of the single contact point from Article 16(3). The solution has been widely regarded as contributing to a streamlined permitting process, including a single licensing process, and mitigating costly delays during the construction phase.

The Danish Energy Agency ("ENS") is to be used as single point of access to assistance on issues related to all offshore wind permitting. ENS will grant the required permits and will coordinate these with other relevant authorities. Therefore, it is the ENS which serves the project developer in relation to the many, often opposing, interests connected to the establishment of offshore wind power projects, with its scope now further expanded. This means that the permits granted by ENS also contain terms and conditions from other authorities, such as the Danish Nature Agency, the Danish Maritime Authority, the Danish Coastal Authority, the Danish Agency for Culture, the Ministry of Defence, etc.[243]

Even though very good implementation such as the above exists, the establishment of centralised Single contact point for permitting coordination shows varied progress across Member States, with most exhibiting partial implementation or systems under development rather than fully operational solutions.

While all Member States have established some forms of contact points, the process is rarely unified. In quite a few cases single contact points have limited role and provide, for example, only information or 'guide' the developers without more active engagement (e.g. Ireland, Poland).

While there has been an effort to streamline information around Member States' permitting processes, in quite few cases the role of the contact point is merely informative.[244]

2.4 Technology-specific provisions

The reason these provisions are grouped together for the purpose of this Report stems from another layer of difficulty in quantitively measuring their dedicated impact on the actual length of the permitting process or the deployment rate of specific RES technologies. This is because with the lack of general data on the length of permitting procedure, the availability of their subsequent breakdown into specific subsets is even more challenging.

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[242] Concept visualised: https://initiatives.weforum.org/clean-power-and-electrification/casestudy1

[243] https://ens.dk/sites/default/files/media/documents/2024-11/offshore_wind_development_0.pdf

[244] European Commission: Directorate-General for Energy, COWI, Eclareon and Prognos, Monitoring the implementation of the Commission recommendation and guidance on speeding up permit-granting procedures for renewable energy and related infrastructure projects – Final report, Publications Office of the European Union, 2025, https://data.europa.eu/doi/10.2833/2257747

Technology-specific provisions, as introduced in Section 1 of the analysis, encompass shorter deadlines for all technologies. Article 16c sets rules to simplify repowering procedures. Article 16d addresses deadlines for solar installations on artificial structures, as well as small-scale solar installations. Article 16e governs the permitting time for heat pumps.

The self-declared status of Member States with regards the transposition status of these Articles as of June 2025 is the following:

- Article 16b is fully transposed in 2 Member States and partially transposed in 14 Member States. Eight Member States have not transposed these provisions. The transposition of this Article in 3 Member States has not yet been analysed due to the late submission of the required measures.
- Article 16c is fully transposed in 1 Member State and partially transposed in 12 Member States. Eleven Member States have not transposed these provisions. The transposition of these Articles has not yet been analysed in 3 Member States due to their late submission of the required measures.
- Article 16d is fully transposed in 3 Member State and partially transposed in 13 Member States. Eight Member States have not transposed these provisions. The transposition of these Articles has not yet been analysed in 3 Member States due to their late submission of the required measures.
- Article 16e is fully transposed in 3 Member State and partially transposed in 10 Member States. 11 Member States have not transposed these provisions. The transposition of these Articles has not yet been analysed in 3 Member States due to their late submission of the required measures.

The analysis of implementation in practice of the permitting provisions was prepared within the remit of the First Interim Report "Monitoring progress of measures to streamline permit-granting procedures under revised RED and Emergency Regulation and development of permitting-related KPIs". Important to note that this assessment does not necessarily correlate with the transposition checks status presented above, as the former looks, to the extent possible, into the effective functioning of permitting deadlines, while the latter encompasses legal assessments.

To this end, permitting deadlines for renewable energy projects can be grouped into three main categories. The first category includes Member States that have established clear deadlines which had an impact on the permitting duration. Italy has incorporated the six-month permitting cap and introduced streamlined procedures for small-scale solar PV projects, alongside partial exemptions from the need to go through an EIA. Its use of tacit consent has proven instrumental in reducing administrative inertia. The Netherlands also benefits from pre-existing national legislation with sometimes shorter deadlines than those set by the Emergency Regulation, supported by a penalty system for late decisions, although not aimed specifically at accelerating permit-related decisions.

The second category includes Member States that have established deadlines, but considerable delays are observed. Germany has included the deadlines in federal law but lack of legal consequences for missed deadlines means that projects may get delayed. In France, permitting timelines have improved through legislative reform and digital tools, but remain inconsistent across departments. Greece has also established deadlines and milestones, but they are not realistically respected.

The third category includes Member States where deadlines have been partially, or not implemented and considerable barriers remain. Poland has partially introduced shorter deadlines, while deadlines for repowering are not yet in place. In Sweden, permitting is handled on a case-by-case basis without binding repowering rules concerning shorter deadlines. Romania continues to apply outdated time limits and treats repowering as equivalent to new construction, even though legislation is in place. Spain's fragmented legal landscape lacks a unified permitting timeline, also due to regional authorities applying the rules differently.

To conclude, the common obstacle across most countries is that even where deadlines are legally prescribed, they are often undermined due to lack of administrative staff and/or complex procedures.

3. CONCLUSION

Despite challenges with dispersed data on permitting processes and some Member States not having transposed the permitting provisions in their entirety, it still can be observed that the most advanced Member States in their implementation are also the ones who demonstrated a substantial acceleration of renewable deployment in the corresponding period.

In terms of effectiveness, it can be observed on the example of Germany that taking full advantage of the solutions laid down in the Emergency Regulation and the revised RED has accelerated the RES permitting process substantially, resulting in an exponential increase of RES deployment rates. Some granular positive developments may also be observed in both these areas in the Netherlands or Portugal. For the majority of the remainder of Member States, the effectiveness is to be confirmed only once more comprehensive national framework is put in place and subject to availability of the comprehensive data pertaining to the permitting processes. It needs to be highlighted that stakeholders are not yet reporting many changes on the ground, indicating that despite the ambitious framework, targeted amendments may be needed.

Similar conclusions can be drawn in relation to efficiency of the measures. An adequate implementation of the provisions of the Emergency Regulation and revised RED results in setting up binding deadlines for the duration of the process, hence inherently contributing to the efficiency of the permitting of renewables and related infrastructure.

The coherence with broader EU energy and climate policy objectives is thoroughly ensured, as renewables constitute a cornerstone for both the EU green transition and its energy independence, which reinforces security. Any policy intervention aiming at deployment of more renewables into the EU energy system contribute to these overarching objectives.

Thus, the current framework has resulted in improvements in terms of effectiveness, efficiency and coherence of the renewable energy permitting in the EU, as well as it demonstrated the EU added value and relevance. However, more comprehensive datasets would be required to measure the impact of the permitting provisions in a structured manner.

Lastly, it is also to be noted that even though the current provisions, for renewable energy permitting has showed some promising results, the level of renewable energy capacity that it is needed for reaching our 2030 targets and even beyond require much faster and more renewable energy development and therefore additional measures may contribute to their further fine-tuning.

ANNEX 8: MONITORING

The success of the preferred policy option can be measured against the following operational objectives and set of indicators, in particular addressing:

- the extent to which projects included in network developments and selected as PCIs/PMIs address appropriately and effectively identified infrastructure needs;
- the effective and increased use of cost-sharing tools;
- the simplification of permitting procedures
- shortening of permitting lead times and meeting current deadlines;
- the enhanced physical and cyber security and resilience of energy infrastructure.

1) Projects included in network development plans and selected as PCI/PMIs address appropriately and effectively identified infrastructure needs. The achievement of this objective will be assessed through matchmaking projects included in network development plans with the identified needs and ensuring that selected PCI/PMIs projects are assessed and validated based on clearly defined criteria, demonstrating that they effectively address infrastructure needs identified. The preferred policy option should reduce the gap between the identified needs and TYNDP and PCI/PMIs should decrease by most cost-effective solutions. The following indicators will be used:

- the number and total capacity of new cross-border interconnectors approved/implemented;
- the extent to which identified infrastructure needs are addressed by infrastructure projects (capacity) included in the TYNDP (planned, under construction or commissioned) or other non-wired solutions (presence of the gap between needs and projects, and decrease of the gap);
- the uptake of non-wired solutions in terms of number of projects and respective increase in grid capacity;

2) The more effective use of cost-sharing tools for faster deployment of cross-border infrastructure projects. By facilitating and supporting the adoption of cost-sharing tools among cross-border infrastructure project stakeholders, project deployment time should reduce compared to the status quo, as tracked by deployment timelines and stakeholder feedback. It will be monitored through:

- the number of binding cost-sharing agreements enabling the implementation cross-border projects;
- the average duration for reaching a cost-allocation agreement;
- the number of non-hosting countries contributing to cost-sharing agreements;
- the number of projects being as part of bundles being submitted for PCI/PMI status.

3) Shorter and simpler permitting procedures for energy infrastructure, renewable energy assets, storage projects, and recharging stations. This is expected to lead to shorter lead time to obtain the necessary permits, making it possible to meet the existing deadlines fewer permit requirements, a reduction in documentation to be assessed in the permitting procedure, and reducing duplication of data recorded through digitalisation and centralised recording.. As the preferred option includes a measure on centralisation and digitalisation of the permitting procedure in the Member States. This is specifically designed to facilitate data collection and

allow to identify the remaining bottlenecks. Together with information from stakeholders it will be the base for a coherent monitoring using the following indicators:

- the average and maximum total duration of permitting procedures in years;
- the yearly rate and average delays in the permitting procedure of projects of common and mutual interest (in years);
- the rate of digitalisation of permitting procedures - in percentage and number of Member States deploying digital procedures, permitting management platforms and centralised archives for the relevant data (in a format that is easily accessible to the relevant stakeholders);
  the level of opposition faced by projects of common interest (number of written objections during the public consultation, number of legal recourse actions).

4) Enhanced physical and cyber security and resilience of cross-border energy infrastructure (PCIs/PMIs) which should achieved by increasing the number of protection and resilience equipment and installations on critical network elements. The success will be monitored through the risk assessments and resilience testing outcomes for specific infrastructure done at national level. Following indicators will be used for monitoring:

- the number of PCIs and PMIs improving physical and cyber security of existing and new grid infrastructure;
- number of critical cross-border infrastructure assets covered by updated resilience/security measures;

Ultimately, the proposed policy option should lead to timely implementation of the necessary infrastructure projects reducing the overall energy system costs and bringing sustainability, market integration and security of supply benefits. This will be measured by looking at:

- the integration of renewable energy sources and reduced greenhouse gas emissions;
- increase in grid hosting capacity;
- the interconnection level between Member States;
- change in energy system adequacy;
- number of reported major incidents or disruptions affecting critical energy infrastructure;
- assessment of evolution of energy system costs.

The achievement of the specific and operational objectives will be tracked based on existing monitoring requirements of ACER to avoid duplication. Concretely, monitoring of the following data will be conducted using ACER deliverables and sources of data:

- Annual monitoring report on congestion management and capacity allocation, which will assess how efficiently existing capacity is used and what the improvements have been as a result of the initiative.

- Biennial monitoring of consistency between the Union-wide TYNDP and national network development plans

- Annual monitoring of progress of PCI and PMI projects and permitting processes by ACER as well as national authorities.

- Monitoring of the application of non-wired and grid enhancing technologies based on data publicly available by the Joint Allocation Office (and used by ACER in their monitoring reports)

- Annual monitoring of the achievement of the interconnection target, done as part of the European Semester assessment

ANNEX 9: DESCRIPTION OF POLICY MEASURES

Annex 9 provides a detailed description of the policy measures referred to in Section 5.2.1 of the Impact Assessment Report.

Specific objective	**Policy measures**		**PO 1**	**PO 2**	**PO 3**
E) Infrastructure planning and project implementation					
SO1: Ensure that projects included in network plans address appropriately identified needs	A.1	Strengthening the existing framework	X		
	A.2	Increased EU level steering and coordination		X	
	A.3	Fully centralised approach			X
	A.4	Alignment of scope (smart gas grids/ blending, electrolysers, PMIs)	X	X	X
	A.5	Broadening scope of PCI categories (modernisation and digitalisation)[245]		X	X
F) Cost and benefit sharing					
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	B.1	Enhancing transparency and strengthening EU principles for cross-border energy infrastructure costs and benefits sharing	X	X	X
	B.2	Use of congestion income for financing of cross-border electricity infrastructure as an incentive to cost-sharing	X	X	X
	B.3	Enabling framework for voluntary bundling of projects		X	X
	B.4	Mandatory offshore regional planning and cost-sharing			X
G) Permitting					
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and, storage projects as well as recharging stations	C.1	Supporting the implementation of existing legislation and issuing guidance	X	X	X
	C.2	Targeted legislative changes to accelerate permitting		X	X
	C.3	Centralised EU wide permitting coordination regime for certain large-scale energy infrastructure projects ("28th Regime")			X
H) Security					
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	D.1	Including physical and cyber-risk resilience considerations in the monitoring of PCIs and PMIs	X	X	X
	D.2	Additional transparency requirements regarding the ultimate beneficial owners of candidate PCIs/PMIs		X	X
	D.3	Including security and resilience-related equipment for the upgrade of existing electricity cross-border infrastructure under TEN-E scope		X	X

[245] On the broadened scope to better reflect security/resilience within the PCI scope see policy measure D.3

A. Infrastructure planning and project implementation

A.1 Strengthening the existing framework

Measure A.1 proposes limited changes to strengthen the existing infrastructure planning framework. To simplify and streamline the PCI/PMI selection process and contribute to reaching specific objective 1, the ACER opinion on the draft PCI/PMI list would be removed as it comes late in the process and hence has a limited impact on the final outcome. The aim is to ensure more effective ACER involvement that would come in earlier stages of the process This implies a shift from the *ex post* opinions by the Commission and ACER as well as approvals on the draft scenarios and draft infrastructure gaps identification report towards *ex ante* steering. For this purpose, this measure would require the development of a framework methodology for scenario and needs identification by ACER and would strengthen ACER's and NRAs' role in the verification of the TYNDP inputs to the PCI/PMI process and monitoring of the implementation. It would also include a simplified application and evaluation process for mature PCIs and PMIs. PCIs and PMIs which have already reached final investment decision or have received a CEF grant for works and which show continued progress in their implementation should retain their PCI/PMI status without the need for resubmission and reassessment.

In electricity, the scope of the planning would be expanded to better consider non-wired solutions and internal grid reinforcements. Timing of the TYNDP including its scenarios and infrastructure need identification would remain the same as under the existing legal framework, with the TYNDP being delivered every two years. Regarding the national level, there would be limited changes to the provisions on the electricity transmission network development planning to mirror the Gases Directive provisions in the electricity legislation (notably the Electricity Markets Directive) and ensure alignment of obligations applying on all electricity TSOs. These requirements demand national coordination on scenarios between electricity, hydrogen and gas sectors as well as consideration of local heating and cooling plans, where applicable, as well as the deployment of alternative fuels infrastructure under the Alternative Fuels Infrastructure Regulation (AFIR), and projects for industrial facilities and industrial hubs.[246]

A.2 Increased EU level steering and coordination

Building on Measure A.1, measure A.2 would move from a "bottom up" towards a more "top down" cross-border infrastructure planning approach ensuring greater transparency, scrutiny and coherence of inputs used in network planning both at European and national level. It involves the Commission, ACER and NRAs earlier in the planning process and simplifies the application and evaluation process for mature PCIs and PMIs.

The Commission would be responsible for the development of a comprehensive central scenario, which would be developed at least every 4 years (instead of existing two-year cycles). Targeted updates would still be possible more frequently and might be needed in case of significant market developments (or external geopolitical circumstances). Updates may be particularly relevant for hydrogen infrastructure planning, given the high level of uncertainty in market developments, changing assumptions on hydrogen uptake. The ENTSOs and ENNOH would be responsible for scenarios/sensitivities data collection, based on Commission guidelines ensuring more consistency and transparency. Stakeholders, NRAs and Member States would be involved in the

[246] The creation of low-carbon industrial clusters, as assessed in the context of the IDAA, can contribute to industrial demand projections for grid planning purposes.

development of scenarios and use of newest data on assumptions on future development of generation and demand.

A strengthened infrastructure needs identification would be also done every 4 years, and when relevant every 2 years, based on the central scenario and the sensitivities developed by the Commission. Responsibility for the needs assessment would remain with the ENTSOs and ENNOH as in Measure A.1 but be based on framework guidance developed by ACER in line with the principles defined in the TEN-E Regulation. The ENTSOs would present the results of their needs assessment at least until 2050. As part of the process and before the publication of the final results, ACER/NRAs would validate the correct application of the framework guidance followed by approval of the results by the Commission and Member States. Stakeholder involvement, including in particular the ENTSOs, ENNOH and the EU DSO Entity, would be ensured by their consultation when developing and approving the guidance for the needs assessment by ACER, as well as during the needs identification process itself (conducted by ENTSOs). Project collection and assessment for the TYNDP and the PCI/PMI selection process would continue to be conducted every 2 years The central scenario would ensure higher credibility and comparability of projects and their costs and benefits. It would be less driven by (national) TSOs, represented by ENTSOs, but by the Commission and the Agency with close involvement of all Member States ensuring network planning captures EU policy targets as well as Member States' perspectives and ensures alignment. There would be a closer link between the EU central scenario and national scenarios used in network planning, improving coordination between the EU and national levels of infrastructure development

This measure would entail a requirement to fully consider non-wired alternative solutions as a priority when addressing the identified needs (based on the accompanying cost-benefit analysis). Also, it would entail an additional planning element for electricity to ensure all identified needs are addressed. A gap filling mechanism would be introduced to ensure that all remaining needs that cannot be addressed by non-wired solutions and for which no TYNDP projects have been submitted are addressed. First, relevant TSOs would be required to propose possible solutions under the scrutiny of NRAs and Member States steered by the Commission with the support of ACER. Second, in case no projects are proposed by the TSOs, the Commission in cooperation with hosting Member States may launch a call for project proposals, which may be delivered by TSOs or other project promoters.

This measure also assumes closer involvement of regional cooperation fora (such as Regional Groups) in the process to facilitate the identification of priorities and appropriate follow-up. On a national level, besides fully mirroring requirements of the Gas Directive on scenario coordination, for the electricity sector this measure would introduce requirements to better link national and European planning by requiring use of the central scenario as one of the scenarios. This which would be a prerequisite for NRA approval of NDPs. This measure would also suggest prolonging the period of network planning on a national transmission grid level for electricity from existing 5-10 to 15 years, to allow catering for anticipatory investment.

A.3 Fully centralised approach

Measure A.3 entails a full shift from the current primarily bottom-up planning and needs identification approach to a full top-down coordination and project selection at the European level. The main activities of the scenario development, needs assessment and projects assessment (for cross-border infrastructure projects under the TYNDP) would be done by an entity at EU level complementing national planning processes. Relevant national actors, such as system operators and regulators would still be involved, providing relevant information on local and national grid characteristics. The EU-level entity would have legally defined links with European Commission, ENTSOs/TSOs, ENNOH/HTNOs, ACER/NRAs, Member States, and other relevant national authorities to ensure data sharing and verification by all concerned parties.

This entity would be responsible of the entire planning process, including scenario development and the associated data, run market and network studies to identify infrastructure gaps, assess the benefits of projects and draft and publish the planning reports. The role of ENTSOs/TSOs and ENNOH/HTNOs would be limited to providing information for which their unique expertise in networks is required. The scope and granularity of the scenario development and needs identification would be the same as in measure A.2. Addressing the identified needs (gap filling mechanism) would build on measure A.2 and be steered by the new entity. In electricity, there would also be an obligation to compare non-wired alternative solutions and infrastructure solutions and cover the needs identified. However, Member States would have to approve projects in their territory and have the right to veto any PCI/PMI candidate projects to be located in their territory, in line with the TFEU.

No existing entity would seem equipped with the necessary expertise, and this would therefore require the transformation of an existing one or the creation of a new entity. Among existing EU entities ACER or CINEA might appear as possible candidates. However, there are considerable limits to the possible transfer of the envisaged tasks to these agencies. The mandate of CINEA, as an executive agency of the Commission, is limited to implementing Union programmes (2021-2027 MFF) on its behalf. Entrusting it with infrastructure planning would entail a significant extension of its mandate going beyond the scope and remit of executive agencies. ACER as a decentralised regulatory agency has been set up as separate legal entity distinct from the EU institutions, to perform specific technical tasks that help the EU institutions and Member States to implement policies and take decisions. ACER taking up tasks in relation to the selection of specific infrastructure projects would raise concerns over conflict of interest with possibly overlapping planning and scrutiny powers. This could also question the independence of regulatory authorities themselves which are represented in the Agency's Board, and trigger backlash from Member States and stakeholders.

A.4 Alignment of scope (smart gas grids/blending, electrolysers)

To ensure that the electrolysers are recognised under the TEN-E have significant cross-border relevance, measure A.4 suggests **raising the minimum installed capacity threshold for electrolyser projects from the current 50MW to at least 500MW (or 1000MW),** along with introducing new criteria to confirm network impact—such as network-related function for both the electricity and the hydrogen networks with a view to overall system flexibility. These changes would cater for a better alignment of this category with the objectives of the TEN-E framework and would reflect the trends observed throughout two cycles of implementation of the TEN-E Regulation on electrolysers (see section 2.2.3 of IA Report and Annex 7). EU policy and financial support[247] to electrolysers will remain very important to scale up the hydrogen segment and the changes in the TEN-E will complement the policy landscape by better targeting of cross-border impact.

With a view to clarifying and strengthening the objectives of the Regulation in promoting infrastructure dedicated to the exclusive use of hydrogen, this policy measure would include removing any incentives for projects for blending hydrogen with natural gas via three main groups

[247] Horizon Europe, the Innovation Fund, the Hydrogen Bank, the Recovery and Resilience Fund and Cohesion funds, as well as State aid.

of amendments. Firstly, it would **remove the smart gas grid category from the scope of the TEN-E Regulation** in line with recent legal and policy updates with a view to ensuring that no support is given to projects involving hydrogen blending which pose risks of circumventing the discontinuation of support to natural gas grids under the TEN-E Regulation, or to TSOs that aim at levels of hydrogen blending that may raise interoperability issues at cross-border interconnection points and fragment the internal market., Secondly, **it would remove the possibility of blending** that currently exists under Article 31 of the TEN-E Regulation for dedicated hydrogen assets converted from natural gas assets falling under the energy infrastructure category set out in point (3) of Annex II to be used for transport or storage of a predefined blend of hydrogen with natural gas or biomethane during a transitional period ending on 31 December 2029. Thirdly, it would amend the definitions of 'dedicated hydrogen assets' and of 'repurposing' to ensure that these target exclusively pure hydrogen.

A.5 Broadening scope of PCI categories (modernisation and digitalisation)[248]

To better include non-wired solutions in planning, policy measure A.5 would introduce a **change to electricity grids PCI category** to more prominently include non-wired solutions. Furthermore, to **better reflect contribution of internal lines** to cross-border electricity trade (and flows), the existing 500 MW threshold would be lowered to 200 MW.

B. Cost and benefit sharing

B.1 Enhancing transparency and strengthening EU principles for cross-border energy infrastructure costs and benefits sharing

Measure B.1 aims at enhancing early transparency in the assessment of project benefits and costs to encourage the involvement of non-hosting EU countries. It also aims to establish a streamlined CBCA process and a more harmonised EU cost-sharing framework to support discussions amongst NRAs. More specifically, it would entail the following elements:

- ENTSO-E and ENNOH would be required to publish Cost benefits analysis (CBA) results showing how the benefits of TYNDP projects are distributed across countries, including non-hosting countries who significantly benefit from such projects. This information would be published as part of the TYNDP. Project promoters would then be encouraged to submit a preliminary non-binding cost-sharing agreement as part of their PCI/PMI application, considering ENTSO-E's and ENNOH's assessment of cross-border benefits in the TYNDP.
- ACER would be mandated to update its recommendation on the treatment of investment requests for PCIs and PMIs (or CBCA recommendation) based on CBCA principles outlined in the TEN-E Regulation such as scenarios to be used, benefits and costs to be included, cost-sharing keys, ex post conditions etc. Those principles would ensure consistency across Member States and across CBCAs. Updating its recommendation, ACER would also need to take into account the differences between the electricity sector and the emerging hydrogen sector. ACER would retain its role of last-recourse decision-maker for CBCA decisions. It would also be tasked with improving transparency and facilitating CBCA processes by developing a non-binding CBCA template and hosting a

[248] On the broadened scope to better reflect security/resilience within the PCI scope see policy measure D.3

central CBCA repository on its website to facilitate the work of project promoters and NRAs.

B.2 Use of congestion income for financing of cross-border electricity infrastructure as an incentive to cost-sharing

Under measure B.2 congestion income would be used to create an additional tool for unlocking cost-sharing discussions for infrastructure projects which generate relevant benefits beyond the borders of their hosting Member States, where the benefits within the hosting Member States do not outweigh the costs. The Commission would be empowered to provide detailed rules on the use of congestion income for financing cross-border electricity infrastructure under the Electricity Regulation. TSOs would be required to allocate a share of the congestion income to PCIs. This financing capacity would be spent on PCIs addressing the biggest bottlenecks in the European or regional energy systems. This should facilitate reaching agreements on cross-border cost allocation, particularly for projects that generate substantial benefits for Member States other than the host country. **B.3 Enabling framework for voluntary bundling of projects**

Measure B.3 seeks to incentivise increased financial contributions from Member States towards cross-border energy infrastructure projects that generate benefits beyond their host countries. This would primarily target regional flagship projects, such as a meshed offshore network in the North Sea. This measure is inspired by past examples where the bundling of five prioritised Nordic grid reinforcements[249] as part of the 2004 TSO Nordel Infrastructure Package and supported politically by the concerned Member States[250], as enshrined in the Ministerial Nordel agreement, led to the successful implementation of the related projects[251]. In addition, such voluntary bundling approach is also already initiated by several North Sea Member States and TSOs, having been initiated by the Offshore Transmission Coalition (OTC) and North Seas Energy Cooperation (NSEC)[252]. This measure entails the establishment of an EU-level framework that facilitates the identification and voluntary bundling of cross-border projects. These projects would be grouped together to enable and encourage cost-sharing discussions amongst relevant Member States (and third countries). Specifically, this framework would facilitate project promoters to jointly submit PCI applications and, TSOs and NRAs to prepare coordinated CBCAs for the bundle of projects. This approach would also facilitate the submission of subsequent funding applications under CEF for the bundle of projects.

While the voluntary bundling of projects is already possible in principle, certain legislative changes are required to allow for project bundles to fully benefit from the cross-border cost allocation provisions under the TEN-E framework. For instance, a new definition of project bundles would be introduced that would allow for specific references in the cross-border cost-allocation framework currently designed for project-specific PCIs/PMIs.

B.4 Mandatory offshore regional planning and cost-sharing

Measure B.4 introduces a mandatory regional planning for offshore cross-border infrastructure projects within sea-basins where hybrid or cross-border radials are already planned. TSOs would be required to undertake a joint regional planning exercise, building on the non-binding sea-basin

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[249] 1. Fennoskan II (Decided) 2. Great Belt (Decided) 3. Nea - Järpströmmen (Decided) 4. South Link (Decided) 5. Skagerrak IV (Letter of Intent, concessions applied).
[250] Sweden, Norway, Denmark, Finland
[251] EMG 2008
[252] Offshore TSO Collaboration, https://www.tennet.eu/offshore-tso-collaboration

offshore renewable agreements of Member States. This would be followed by a mandatory preliminary cost-sharing agreement by NRAs for the bundle of projects at the stage of the PCI and PMI application, and the requirement of a final cluster-CBCA decisions for the purpose of CEF. This measure would replace the current Offshore Network Development Plan (ONDP) and Sea-Basin cross-border cost-sharing (SB-CBCS) provisions for relevant sea-basins. It would therefore build on existing process and initiatives such as OTC and prepare the ground for the possible sue of such regional planning in other areas.

C. Permitting

C1. Supporting the implementation of existing legislation and issuing guidance

Measure C.1 entails increasing the policy efforts and adopting new non-legislative measures but not introducing new legislative measures. In this scenario, the Commission reinforces the support aiming to ensure a better implementation of current permitting acceleration measures, especially those of the revised RED. It would support Member States to implement best practices in planning and permitting of electricity infrastructure, renewable energy and storage projects, as well as recharging stations. Member States must intensify their efforts by ensuring full transposition and optimal implementation of the revised RED, and the Gas Directive, paying particular attention to the permitting and spatial planning of RES, co-located storage and associated infrastructure. Simultaneously, they will need to invest in digitalisation of permitting procedures and staffing and skilling of permitting authorities. The Commission would support the implementation process through Commission guidance documents and strengthened dialogue with stakeholders and Member States' authorities in existing expert groups and cooperation platforms managed by the Commission. Further, it would look to address the lack of capacity in national permitting authorities, working to identify technical assistance and funding opportunities that could support necessary investments, reforms and trainings to simplify permitting procedures and build capacity in permitting authorities. Lastly, specifically on the matter of environmental assessments, the Commission would pursue guidance on the implementation of environmental legislation in connection to the permitting procedures. This measure would also leave the permitting of storage (other than co-located) and recharging stations, and general electricity distribution and transmission grids without a dedicated legal framework at EU level.

C.2 Targeted legislative changes to accelerate permitting

Measure C.2 involves legislative amendments targeting the further acceleration and simplification of permitting procedures for cross-border, national transmission and local distribution grids as well as renewable energy and storage projects and recharging stations. The amendments considered may include the following elements which may be introduced in either sector-specific or horizontal legislation[253]:

1) **Establishing an EU-level framework for the accelerated permitting of electricity distribution, transmission and storage assets, and of recharging stations, while adapting to the EU-level provisions on hydrogen infrastructure** with a scope that would extend beyond PCIs and PMIs, and include measures such as: a single point of contact for permitting; strengthened cooperation requirements in the permitting of cross-

[253] Regarding the amendments proposed, the Commission is working towards an Omnibus package in the environmental sector to be adopted in Q4 2025, which may include provisions to simplify and accelerate environmental permitting and environmental assessments provisions.

border projects; maximum durations for administrative decisions aligned with the 2 year deadline applicable to hydrogen; introducing further requirements for the permitting of electricity distribution, transmission and storage assets (introducing it also to renewable and low-carbon hydrogen projects) and of recharging stations, on tacit approval in case of delays subject to certain conditions; a cut-off date for the request of additional data by authorities; digitalisation, data-centralisation and increased administrative support of permitting authorities by Member States; a presumption of overriding public interest for electricity building on the existing provision in the revised RED reflecting the need to match RES expansion with grid development; exemptions from permitting procedures for small installations subject to certain conditions[254], electricity distribution grids and modernisation, reinforcement, repowering and repurposing of existing electricity grid assets;

2) **To strengthen the permitting acceleration provisions of the TEN-E Regulation**: aligning the permitting of PCIs and PMIs with the new acceleration provisions introduced for grids in general (e.g. mandatory digitalisation and overriding public interest for electricity grids) while maintaining a higher level of urgency. In addition, the following measures would be covered **reinforcing the mandatory** scoping process in the pre-application phase that identifies the extent of assessments to be carried out by promoters in order to clarify upfront which assessments are to be provided by the project promoter; reducing the statutory permitting duration to one year and making it legally binding; **simplifying and clarifying** concepts which have been raised as sometimes unclear during implementation such as the early public consultation or the purpose and legal character of the pre-application phase.
3) To **complement and address potential shortcomings of the current permitting framework for renewable energy projects**. Amendments could be proposed to: (1) introduce **new measures on important topics not covered (or only lightly covered) by the RED**, such as measures to minimise the arbitrary identification of "exclusion" areas where the development of RES is prohibited; expand the scope of the fast and simple permitting rules to additional flexibility assets to support the integration of renewable energy into the system, such as stand-alone storage assets and recharging stations; strengthen the provisions on public acceptance by introducing obligations on benefit-sharing mechanisms for renewable energy projects, and measures to improve the staffing of authorities and digitalisation of procedures; (2) **introduce measures building on the Council Regulation (EU) 2022/2577[255] and its extension (EU) 2024/223, like solutions on alternative[256] and compensatory measures[257] (Article 3a)** where scope for further

[254] This should not lead to artificially slicing of projects into the smaller projects ('salami slicing tactic') in the context of Articles 6(3) and 12 of the Habitats Directive, Article 5 of the Birds Directive and the Environmental Impact Assessment Directive.
[255] Council Regulation (EU) 2022/2577 of 22 December 2022 laying down a framework to accelerate the deployment of renewable energy, OJ L 335, 29.12.2022, p. 36–44
[256] In order for projects to receive derogations provided under Articles 6(4) and 16(1) of the Habitats Directive, Article 4(7) of the Water Framework Directive and Article 9(1) of the Birds Directive, the competent authorities must demonstrate among other conditions that no other feasible alternative solution exists that would not adversely affect the integrity of the Natura 2000 site concerned. The introduction of this measure, similarly to the Emergency Regulation, aims to specify that the scope of the assessment of alternative solutions can cover solutions that ensure the achievement of the same objectives as the project in question within the same or similar timeframe and without resulting in significantly higher costs and therefore facilitate meeting this condition.
[257] Member States face additional challenges concerning the requirement to adopt compensatory measures when applying the derogation under the Habitats Directive (92/43/EEC) with regards the plant or installation for the production of energy from renewable sources, or the related grid infrastructure which is necessary to integrate

action may be warranted, such as tightening permitting deadlines and reviewing administrative procedures with regards tacit approval and data request to ensure the fulfilment of the deadlines, further simplification of the administrative procedures for repowering and hybridisation of assets; exempt certain projects from having to undergo any permitting procedure, e.g. small scale installations[258].

4) **To simplify and streamline environmental assessments the Commission** could introduce targeted amendments to environmental legislation[259] such as balance the responsibility of project promoters with a more active role for authorities in what concerns the identification and deployment of compensation and mitigation measures, where the authorities could make lists of standard measures that may be considered by project developers for application if relevant; introduce new measures to simplify environmental assessments, such as, introducing a scoping process with a cut-off date for requests for additional data by authorities, as well as requiring digitalisation and data-centralisation and requirements for environmental data. In addition to simplification, the Commission could consider changes as regards the effect of the overriding public interest provision.

C.3 Centralised EU-wide permitting coordination regime for certain large-scale energy infrastructure projects

Measure C3. introduces a centralised EU ("28th") regime for the permitting of very large energy projects such as interconnectors and large-scale renewable energy projects with cross-border characteristics. This would amount to a significant change of the permitting system shifting the responsibility of monitoring and/or coordinating permitting processes from Member States' contact points/one stop shops[260] to the EU. These coordination tasks would be taken upon by a permanent European coordination authority and would entail monitoring the timely completion of the procedures in line with the EU permitting framework and liaising with Member States (national and local) authorities to ensure that the necessary approvals are issued without delays and that projects are granted priority treatment, without the EU Authority having decision making powers in national procedures. Such tasks entail low risks of conflicts of interest or of authorities' competences. However, to ensuring the effective handling of these tasks at the European Level would require a significant build-up of the necessary legal and procedural expertise and practical capacity.

D. Security

D.1 Including physical and cyber-risk resilience considerations in the monitoring of PCIs and PMIs

Measure D.1 includes provisions similar to those related to climate-adaptation under the current TEN-E Regulation but is focused on addressing resilience against physical malicious acts and cybersecurity threats to the Union's cross-border energy infrastructure. Project promoters would be required to include a risk assessment as part of the implementation plan referred to under

renewables into the electricity system. The introduction of this measure, while preserving a high level of environmental protection, allows for the compensatory measures to be carried out in parallel with the implementation of the project under strict conditions.

[258] This should not lead to artificially slicing of projects into the smaller projects ('salami slicing tactic').

[259] Specifically, the EIA Directive, SEA Directive, Habitats Directive, Birds Directive and Water Framework Directive.

[260] See Annex 6 for further details on the one stop shops, single points of contact and national competent authorities established under the revised RED and Gases Directive and the TEN-E Regulation.

Article 5 of the TEN-E Regulation. Lastly, project promoters would, where needed, provide details on the envisaged physical and cybersecurity mitigation measures in their annual reports, also in the context of the requirements under Article 5 of the TEN-E Regulation. If project promoters are identified as critical entities under the EU Critical Entities Resilience (CER) Directive, they should build on the required risk assessments to evaluate all relevant risks that could disrupt the provision of their essential services and subsequently implement appropriate and proportionate technical, security, and organisational measures to ensure their resilience. As regards the risk assessment for cyber-security, project promoters should take into relevant risk evaluations and assessments carried out at Union level, including assessing impact on cross-border electricity flows, using methodologies pursuant to the Network code on sector-specific rules for cybersecurity aspects of cross-border electricity flows, and the results of the coordinated security risk assessments of critical supply chains carried out in accordance with Article 22(1) of the NIS2 Directive, where applicable.[261]

D.2 Additional transparency requirements regarding the ultimate beneficial owners of candidate PCIs/PMIs

Measure D.2 introduces additional transparency requirements regarding the ultimate beneficial owners of all candidate PCI/PMI projects and their internal shareholder structure. Project promoters would be required to share information about their ultimate beneficial owners as part of the documentation submitted to ENTSO-E and ENNOH during the TYNDP application process. This information would be treated confidentially. ENTSO-E and ENNOH would then be responsible for forwarding this information to the European Commission whenever third-country involvement is identified. The Commission would review this information, which would be taken into account in the assessment of candidate PCI and PMI projects. This information is also relevant given that PCIs and PMIs are considered projects of Union interest under the Foreign Direct Investment Screening Regulation and that the Commission has the right to issue an opinion addressed to the Member State where the foreign direct investment is planned or has been completed where the Commission considers that a foreign direct investment is likely to affect projects or programmes of Union interest on grounds of security or public order.

D.3 Including security and resilience-related equipment for the upgrade of existing electricity cross-border infrastructure under TEN-E scope

Measure D.3 introduces the possibility to include PCIs related to security upgrades of existing electricity infrastructure under the TEN-E framework, including any equipment or installation essential to operate safely, securely and efficiently, including protection, monitoring and control systems. Such upgrades may not necessarily lead to an increase in cross-border capacity, but bring significant cross-border benefits in terms of resilience and security. Such equipment would be eligible for the PCI status and could subsequently benefit from CEF funding. The procurement of such equipment could take into account relevant guidance stemming from the non-binding guidelines to further specify the technical, security and organisational measures that may be taken pursuant to Article 13 of the CER Directive, or otherwise recommendations from EU Protective Security Advisory Missions.

[261] Commission Delegated Regulation (EU) 2024/1366 of 11 March 2024 supplementing Regulation (EU) 2019/943 of the European Parliament and of the Council by establishing a network code on sector-specific rules for cybersecurity aspects of cross-border electricity flows

ANNEX 10: COMPARISON OF OPTIONS

The following table provides a detailed summary table of the comparison of the three policy options as discussed in section 7.

Table 16: Detailed comparison of options in terms of effectiveness, efficiency, coherence, subsidiarity and proportionality relative to the baseline

Impacts	PO1	PO2	PO3
Effectiveness	+	++/+++	++
SO1: Ensure that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs	+	+++	++
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	+	++	++
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations	+	+++	++
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	+	++	++
Efficiency	+	++/+++	+/++
SO1: Ensure that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs	+	+++	++
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	++	+++	++
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations	+	++	+
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	+	++	++
Coherence	+	++	+
SO1: Ensure that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs	+	++	+
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	++	++	+
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations	+	++	+
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	+	++	++
Subsidiarity and proportionality	++	+/++	-
SO1: Ensure that projects included in network plans and selected as PCI/PMIs address appropriately identified infrastructure needs	++	+	-
SO2: Facilitate the use of cost-sharing tools for faster deployment cross-border infrastructure projects	++	++	-
SO3: Shorten and simplify permitting procedures for energy infrastructure, renewable energy and storage projects, as well as recharging stations	++	+	-
SO4: Enhance physical and cyber security and resilience of cross-border energy infrastructure	+	++	++
Summary comparison of options (contribution to general objective)	+	++	+
GO: Timely and efficient development and interoperability of resilient trans-European energy networks, renewable energy, storage and recharging stations necessary to achieve the energy and climate policy objectives (GO)	+	++	+

ANNEX 11: GLOSSARY

Term or acronym	Meaning or definition
ACER	The European Union Agency for the Cooperation of Energy Regulators
AFIR	Alternative Fuels Infrastructure Regulation
Birds Directive	Directive 2009/147/EC of the European Parliament and of the Council of 30 November 2009 on the conservation of wild birds (Codified version) OJ L 20, 26/01/2010, p. 7–25
CAPEX	Capital Expenditures
CBA	Cost-benefit analysis
CBCA	Cross-border cost-allocation
CEF	Connecting Europe Facility
COM	European Commission
CORE CCR	Capacity Calculation Region in the Central Europe
DLR	Dynamic Line Rating
DNDP	Distribution network development plan
DSO	Distribution system operator
EIA Directive	Directive 2011/92/EU of the European Parliament and of the Council of 13 December 2011 on the assessment of the effects of certain public and private projects on the environment OJ L 26, p. 1–21
Electricity Market Directive	Directive (EU) 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast)
Electricity Market Regulation	Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast)
ENNOH	European Network of Network Operators for Hydrogen
ENTSO-E	The European Network of Transmission System Operators for Electricity
ENTSOG	The European Network of Transmission System Operators for Gas
ENTSOs	Referring to both ENTSO-E and ENTSOG
EPBD	Energy Performance of Buildings Directive
EU DSO entity	The European entity for the cooperation of distribution system operators
Gases Directive	Directive (EU) 2024/1788 on common rules for the internal markets for renewable gas, natural gas and hydrogen
Gases Regulation	Regulation (EU) 2024/1789 on the internal markets for renewable gas, natural gas and hydrogen

Habitats Directive	Council Directive 92/43/EEC of 21 May 1992 on the conservation of natural habitats and of wild fauna and flora OJ L 206, p. 7–50
HTNO	Hydrogen transmission network operators
Infrastructure solutions	In electricity, this means installing new hardware infrastructure consisting of electricity cables and lines (both alternate and direct current, overhead lines and underground / undersea cables, including pylons, metering infrastructure, etc.) and other related infrastructure such as transformers, substations, converters.
Non-wired alternative solutions	In electricity, this encompasses other than infrastructure solutions as defined above, including grid enhancing technologies and digital technologies, which can increase available grid capacity. Non-wired alternative solutions inter alia include dynamic and ambient line rating, dynamic transformer rating, static synchronous compensators, advanced power flow control systems, phase-shifters, digital twin platforms or synchronous condensers.
NRA	National Regulatory Authorities
PCI	Project of Common Interest
PMI	Project of Mutual Interest
RED	Renewable Energy Directive
RES	Renewable Energy Sources
SEA Directive	Directive 2001/42/EC of the European Parliament and of the Council of 27 June 2001 on the assessment of the effects of certain plans and programmes on the environment, OJ L 197, p. 30–37
TEN-E Regulation	Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure
TNDP	Transmission network development plan (on a national level)
TSO	(National) Transmission system operator
TYNDP	Union-wide ten-year network development plan
Water Framework Directive	Directive 2000/60/EC of the European Parliament and of the Council of 23 October 2000 establishing a framework for Community action in the field of water policy, p. 1–73