ACER

European Union Agency for the Cooperation of Energy Regulators

Energy infrastructure development in Europe

2026 Monitoring Report - Annex

Additional information on national practices and applied methodologies

6 November 2026



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Contents

A. Connection requests capacities 4
B. End-user demand in EU TYNDP 2024 and EU TYNDP 2026 scenarios 9
C. Electricity infrastructure needs assessment 12
D. Comparison of congestion income and EU TYNDP infrastructure needs 15
E. Grid enhancing technologies in electricity network development planning 19
F. Delays in the EU TYNDP planning process 22
G. Supply chain issues and measures against them 23
H. Congestion income 24
I. TSO capital and operational expenditures 30

A. Connection requests capacities

Table 1: Total capacity of generation and demand applications to transmission and distribution grid in connection queue as of 31 December in 2019 and 2025 (in GW).

Country	Generation				Demand			
	Transmission		Distribution		Transmission		Distribution	
	2019	2025	2019	2025	2019	2025	2019	2025
Austria								
Belgium		1.8				30.76		
Bulgaria		5.9		1.8				
Croatia		2.93						
Cyprus	0.436[1]	0.613[2]			0.009	0.024[3]		
Czechia	5.94	13.15			0.20	0.78		
Denmark	11.60	24.40	20.90	25.00	2.40	32.70	6.40	15.00
Estonia			1.70	0.22			0.33	0.13
Finland								
France		34	13.00	31.00		80		
Germany								
Greece	2.15	48.89	0.67	0.98	0.10	1.02	0.32	0.44
Hungary		10				0.6		
Ireland					0	2.00		1.25
Italy								
Latvia								
Lithuania		1.18				0.03		
Luxembourg				1.4				
Malta			0.03	0.002			0.01	0.01
Netherlands								
Norway		6.7		6.8		6.2		12.9
Poland	3.02	22.21			0.002	5.46		
Portugal								
Romania	0	3.18		27.35				6.07
Slovakia		0.35				0.85		
Slovenia	0	0.09	0.003	0.46	0.01	0.19	0.01	0.36
Spain		15.4		98.1		19.4		8.6
Sweden	26.70	22.63			3.50	32.44		

Source: NRAs data provision in 2026

[1] RES and conventional generation.
[2] RES and conventional generation; the figure excludes 0.88 GW of storage.
[3] The figure excludes 0.525 GW of storage.

Table 2: Annual capacity of generation and demand connection requests to transmission and distribution grid from 1 January to 31 December in 2019 and 2025 (in GW).

Country	Generation				Demand			
	Transmission		Distribution		Transmission		Distribution	
	2019	2025	2019	2025	2019	2025	2019	2025
Austria								
Belgium		1.48				31.68		
Bulgaria		3.8		0.87		10.9		0.5
Croatia		0.3			0	0.03		
Cyprus	0.105[4]	0.014[5]		0.131	0.009	0.024[6]		
Czechia	0	2.85			0	0.20		
Denmark	3.70	8.30			1.80	21.50		
Estonia	0.04	0.84	0.41	7.16	0.03	2.46	0.11	0.32
Finland								
France			4.80	12.30		11		
Germany								
Greece	3.01	6.40	2.90	0.57	0.06	1.20	0.61	0.84
Hungary		3.05				0.6		
Ireland	1.10	8.10	0	0.40	0.5	0.35		0.65
Italy								
Latvia								
Lithuania		3.29	0.76	2.15		0.87	1.87	2.56
Luxembourg				1.39				
Malta			0.01	0.01			0.13	0.14
Norway		9.1				11.7		
Poland	6.06	32.29			0.01	10.29		
Romania	2.19	33.20		15.36				8.41
Slovakia								
Slovenia	0	0.004	0.08	1.17	0.01	0.19		
Spain		41.5		178.8		40.2		50.7
Sweden	22.80	13.57			1.46	9.05	0.14	0.46

Source: NRAs data provision in 2026

[4] RES and conventional generation.
[5] RES and conventional generation, figure excludes 0.525 GW of storage
[6] Figure excludes 0.525 GW of storage.

Table 3: Annual capacity of refused generation and demand applications to transmission and distribution grid from 1 January until 31 December in 2019 and 2025 (in GW) – only for countries with any related data provided.

Country	Generation				Demand			
	Transmission		Distribution		Transmission		Distribution	
	2019	2025	2019	2025	2019	2025	2019	2025
Cyprus	0	0.099[7]		0.0009	0	0		0
Czechia	0	0.15						
Denmark	3.20	6.10			2.7	8.1		
Estonia			0.03	0.65			0.17	0.18
Greece			0.09	0.34				
Lithuania		1.13	2.84	1.05			1.60	0.59
Norway		1.2				2.3		
Poland	0	2.84			0	0.8		
Slovenia			0	0.28			0.24	0.38
Spain		8.6		8.4		3		23.7

Source: NRAs data provision in 2026

Table 4: Connection queue measures introduced in the past 5 years to manage connection queues and/or ensure additional capacity for connection

Allocation of network capacity	Transmission	Distribution
Project readiness or maturity affects the order in which capacity is allocated (e.g. first ready-first served).	BE, CY[8], FI, LV, SE	BE (Brussels), CY, FI, LV, SE
Projects relieving congestion have different treatment enabling their earlier connection.	SE[9]	SE[9]
Capacity is allocated through auctions, tenders or another competitive mechanism.	RO[10]	RO[10]
Available capacity is allocated pro-rata or otherwise repartition among applicants.	BE, FI[11], FR	FI, FR, LV
Priority categories apply to specified projects or grid users.	CY, CZ[12], GR[13]	CY (self-consumers), CZ[12], GR[13], SK
Other/measure or approach to allocate network capacity – (flexible	BE (categorisation of connection requests;	BE (Flanders; consideration of non-market based redispatching for storage and generation)

[7] The applications have been cancelled due to reasons attributable to the applicants.
[8] CY: Project maturity and readiness is applied since April 2026, both for transmission and distribution grid connections. Before this date, the queue was managed according to the first come, first served principle.
[9] SE: DSOs and TSOs can prioritise connections when justified (e.g. enabling other connections).
[10] RO: It concerns generation projects with an installed capacity greater than or equal to 5 MW.
[11] FI: The approach is already applied in practice, but it has not yet been formally confirmed through a separate decision.
[12] CZ: RES projects are prioritised in the connection queues.
[13] GR: Connection queue priority is granted to RES projects with industrial and agricultural PPAs (up to 2.95 GW and 0.5 GW respectively), battery energy storage system (BESS) projects succeeded in regulator's auctions (~0.9 GW) or ministry's auctions (8 GW at transmission and 0.9 GW at distribution level), pumped-hydro storage projects (up to 2 GW), and mature-stage PV projects incorporating unit of at least one hour of storage capability. For merchant BESS, priority is also influenced by proximity to existing substations, while distribution-connected projects (P ≤ 10 MW) are limited to designated substations.

Allocation of network capacity	Transmission	Distribution
connection agreements are not accounted for in this table)	'swimming lanes'[14]), FR (not specified)	
Additional measures are planned.	CZ, FI, FR, GR[15]	CZ, FI, FR, GR
None of the above was introduced or revised in the last 5 years, but some measures are planned in the future.	IE (modification of the connection queue management measures is under consideration), LU	BE(Wallonia)[16], IE (modification of the connection queue management measures is under consideration), LU

Source: NRAs data provision in 2026

Table 5: Connection queue measures introduced in the past 5 years to address non-progressing requests

Addressing non-progressing requests	Transmission	Distribution
Project milestones, maturity requirements or deadlines for maintaining queue position	BE, CY (maturity requirements), FI, GR[17], LU (for generation), RO[18], SE	BE (Brussels), CY (maturity requirements), FI, GR[17], LU (for generation), LV, RO[18], SE, SK
Limited reservation periods for allocated connection capacity	CY (10 days), CZ[19], FI[20], GR (3 years), IE[21], RO (10.5-18 months)[22], SE	BE (Flanders)[23], CY (10 days), CZ[19], FI, IE[21], RO (10.5-18 months)[22], GR[24],SE, SK
Use-it-or-lose-it provisions allowing unused reserved or contracted capacity to be reduced or reallocated[25]	CY (set in the connection agreement), FI[26], FR, GR[27], RO	CY (set in the connection agreement), FI, FR, GR[27], RO
Reservation fees, security deposits or financial guarantees linked to applications or reserved capacity	CZ (non-refundable deposits[28]), FR (fast track procedure), GR[29], IE[30], RO (financial guarantees and auction participation guarantee)	CZ (non-refundable deposits[28]), GR[29], LV, IE, RO (financial guarantees and auction participation guarantees), SK

[14] BE NRA: Swimming lanes present grid users categories used for the processing connection requests by the TSO.
[15] In GR, a law is expected by the end of 2026 addressing connection priority lists and the connection of big consumption units (e.g. data centres). FI considers the prioritisation of projects relieving congestion.
[16] In Wallonia (BE), discussions are ongoing on the introduction of project readiness or maturity criteria and prioritisation of projects and grid users (e.g. relieving congestion) in connection capacity allocation.
[17] Beyond the connection application prerequisites (e.g. environmental terms approval, producer's certificate issued by the Greek NRA, bank guarantee), within 12-24 months the promoter should submit an application for installation license and connection contract. Whereas the assets exempted from producer's certificate must submit the application for Connection Contract within 4 months. If this deadline is not complied with, the 3-year BCT is interrupted.
[18] In Romania, the milestones include financial guarantees for the issuance of technical connection approval, the conclusion of the connection agreement, building and establishment authorisations, connection works completion, fulfilment of obligations in the connection agreement, technical certification for commissioning.
[19] Each connection applicant has a deadline set in the connection contract by which their equipment must be ready for connection. If this deadline is not met and the applicant is not able to justify the non-compliance with the deadline, the capacity reservation the connection contract terminates.
[20] The limited reservation period is already applied but it is not formally confirmed through a separate decision.
[21] The connection offer has a deadline for generators; if not complied with, the connection offer lapses.
[22] 10½ months from the date of issuance of the technical connection approval, if the request for the conclusion of the connection agreement is not submitted to the network operator; 12 months from the date of issuance of the technical connection approval, if the connection agreement is not concluded; 18 months from the date of issuance of the technical connection approval and 12 months from the conclusion of the connection agreement, whichever occurs first, if the building and establishment authorisations are not obtained.
[23] The reservation period is 2-year long with the possibility of justified extension.
[24] The reservation period for assets exempted from the producer's certificate is 10, 30 or 36 months, depending on the technology and topology of the proposed network connection. The period can be extended up to 8 months upon the payment of 1.000 (EUR/MW)/month.
[25] In Sweden, use-it-or-lose-it provisions are not required by law, but the NRA strongly supports it.
[26] Use-it-or-lose-it provisions are already applied but these are not yet formally confirmed through a separate decision.
[27] Under specific conditions RES projects may relocate and apply with priority for new BCTs. Old production licenses of thermal units have the possibility to apply for the modification of the technology of the license to BESS with the same conditions.
[28] In Czechia, the non-refundable deposit aims to prevent speculative connection requests.
[29] Greece applies bank guarantees, both for the submission of the application and inclusion of the project in the priority list. The reservation fee for RES exempted projects equals 1.000€/MW/month up to 8 months.
[30] In Ireland, a capacity bond is forfeited if a generator does not export a certain proportion of its maximum export capacity within 12 months of energisation.

Addressing non-progressing requests	Transmission	Distribution
Fees or penalties related to unused reserved or contracted capacity	FI[31], RO[32]	FI[31], RO[32], SK
Other/measure or approach to address non-progressing projects (please specify below)	CY[33], GR[34]	CY[33], GR[34]
Additional measures are planned	BE, CZ, FR, GR, IE	BE, CZ, FR, GR, IE
None of the above introduced or revised in the last 5 years, and no measures are planned in the future	GR, SK	GR

Source: NRAs data provision in September 2026

Table 6: Responsible party for setting the rules and principles on connection queue management

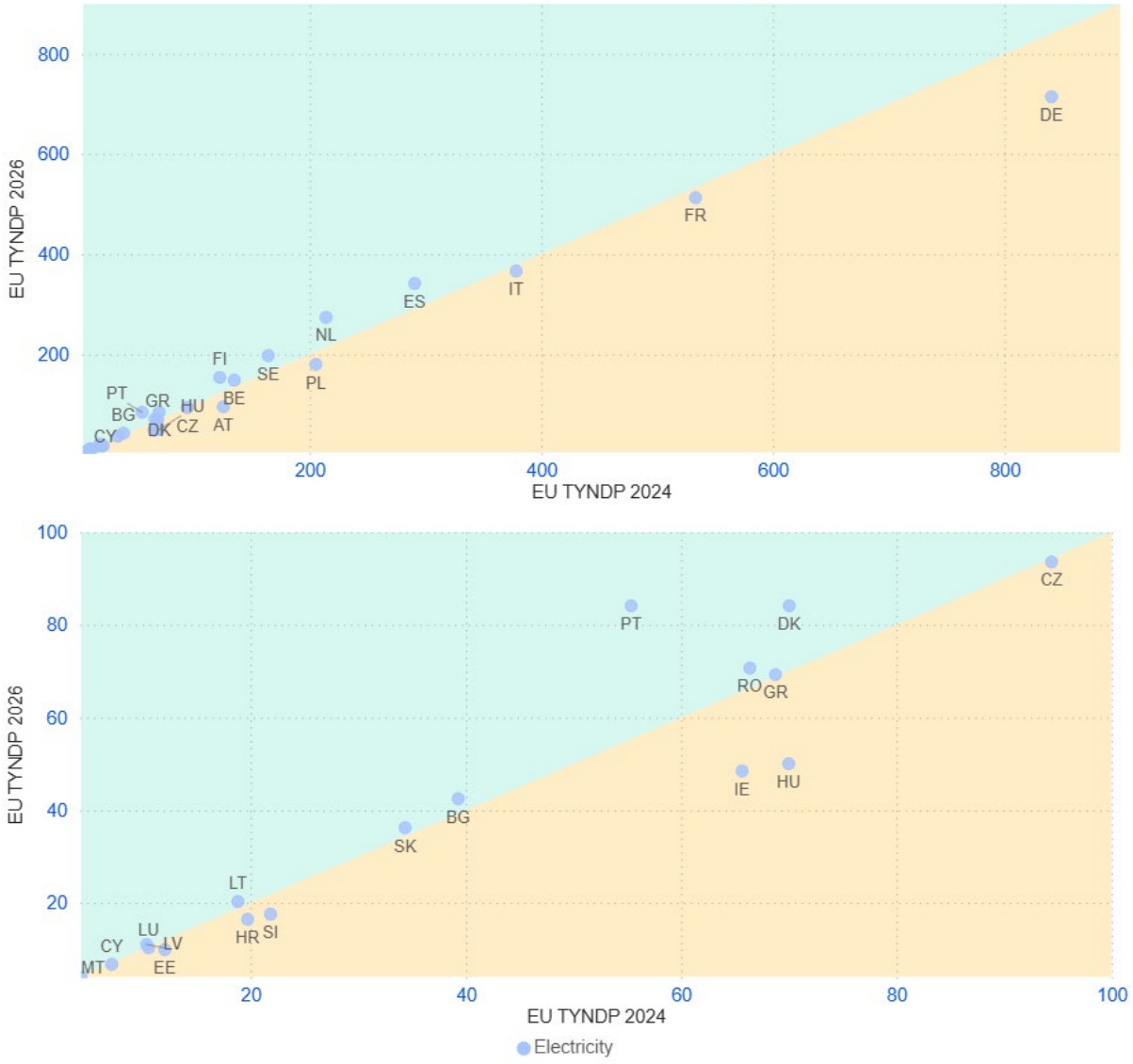
Who is responsible for setting the rules or principles for congestion management in your country?	Country
NRA	BE (Flanders), BE (Brussels), CZ, FI, GR, IE, LV, RO, SE
TSO	CY, FI (may adjust details), FR, IE (operational constraints), LU, LV (connection rules), SE, SK
DSO	CY, FI (may adjust details), FR, IE (operational constraints), LU, LV (connection rules)
Ministry	CZ, FI, GR[35], IE (prioritisation of customer types may require legislation from the Government)
Other	BE (Flanders; Parliament via decree)

Source: NRAs data provision in September 2026

[31] The penalty is the lost connection fee and lost capacity.
[32] Network operators use collected guarantees for network development.
[33] A connection licence is valid for a limited period; if the project is not completed within that period, it must be renewed.
[34] The progress of bigger projects, which require Producer's Certificate issued by the Greek NRA, is evaluated via progress reports submitted by the projects.
[35] Since L. 4951/04.07.2022, the Ministry has taken over initiatives to set priorities in the connection queues of applications' lists of BCTs.

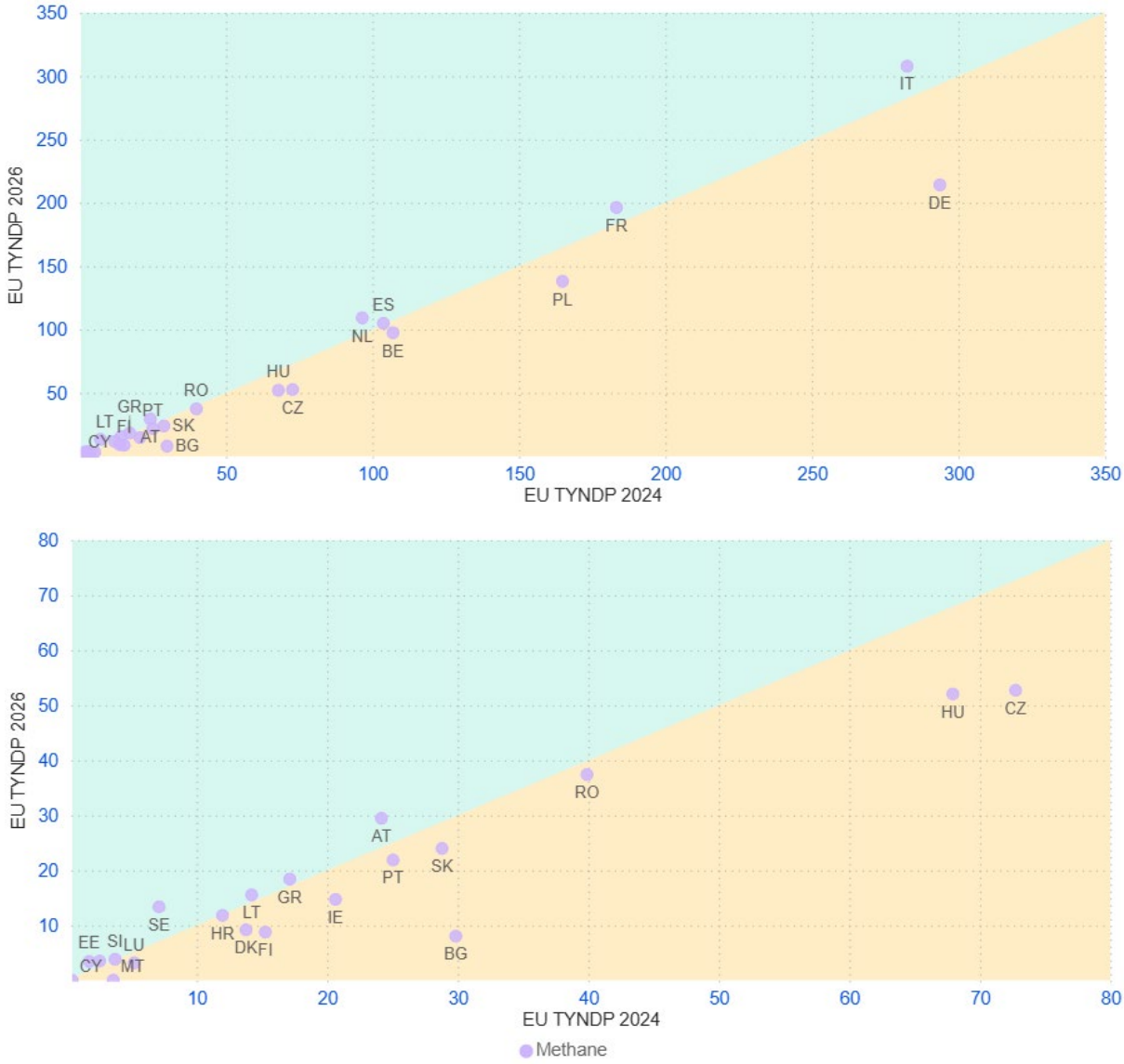
B. End-user demand in EU TYNDP 2024 and EU TYNDP 2026 scenarios

Figure 1: 2040 final (end-user) electricity demand (TWh) in EU TYNDP 2024 and EU TYNDP 2026 National Trends scenarios per sectors and per countries (upper chart: full range, bottom chart: zoom-in)



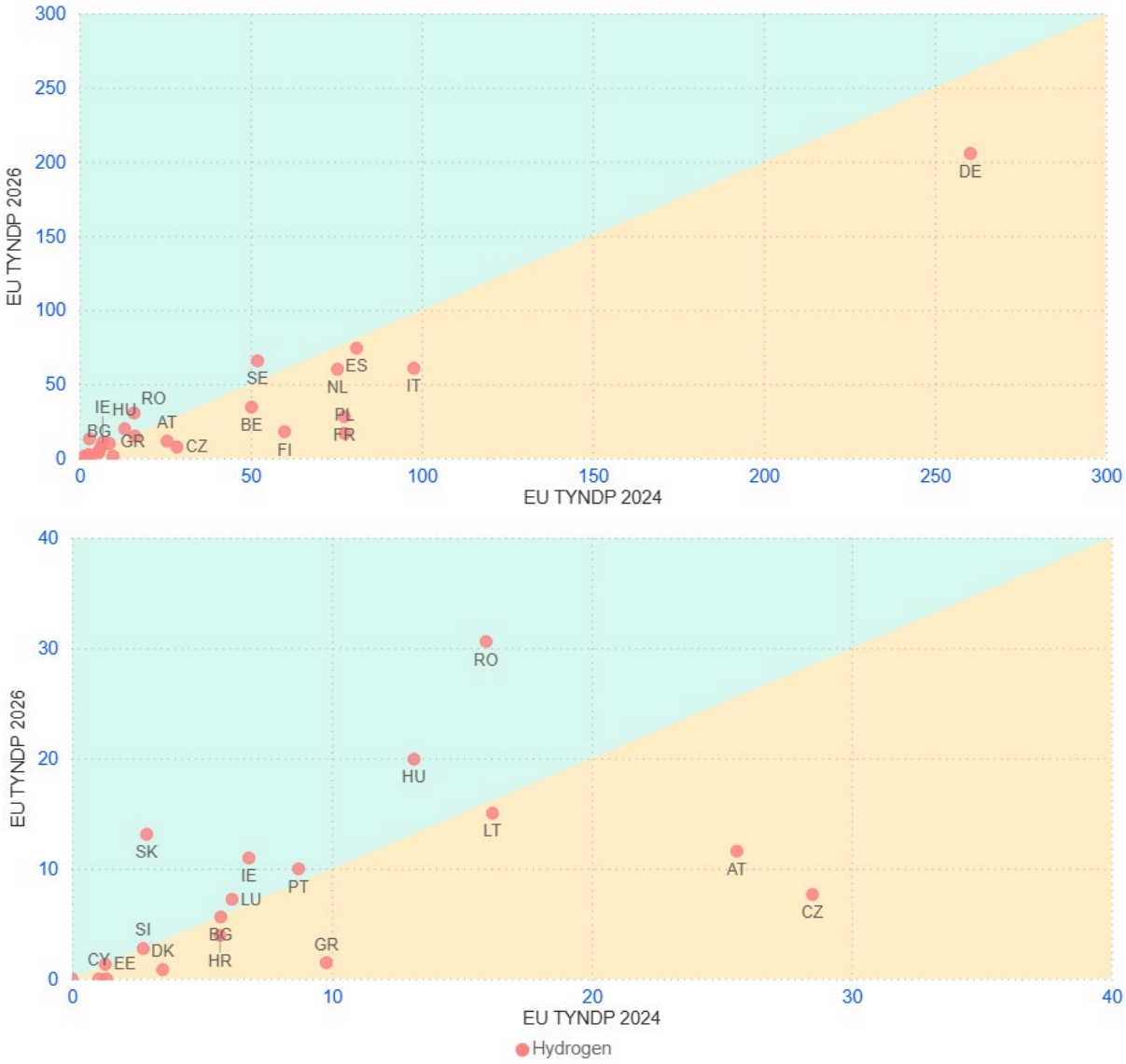
Source: EU TYNDP scenarios 2024 and 2026

Figure 2: 2040 final (end-user) methane demand (TWh) in EU TYNDP 2024 and EU TYNDP 2026 National Trends scenarios per sectors and per countries (upper chart: full range, bottom chart: zoom-in)



Source: EU TYNDP scenarios 2024 and 2026

Figure 3: 2040 final (end-user) hydrogen demand (TWh) in EU TYNDP 2024 and EU TYNDP 2026 National trends scenarios per sectors and per countries (upper chart: full range, bottom chart: zoom-in)



Source: EU TYNDP scenarios 2024 and 2026

C. Electricity infrastructure needs assessment

Table 7: Per-country information on assessments of electricity infrastructure needs

	Quantitative assessment of electricity infrastructure needs by the TSO	Additional information
Austria	No	-
Belgium	Yes	The NDP does not identify 'needed GW per border'. It works based on realistic project candidates. The TSO does estimate the amount of additional capacity needed, but the concrete project will not necessary exactly match this estimate. First, structural network congestion is identified together with its expected evolution in internal grid and on interconnectors which would justify reinforcements or new developments. Potential reinforcements or new developments are then identified. At least one project per border is considered and its time horizon depends on the identified needs and priorities. Each project candidate is evaluated using cost-benefit analysis and only projects with positive CBA are potentially further developed. The other candidates remain monitored in the context of the evolution of the energy system. The last version of the NDP was adopted in 2023 and spans across the period 2024-2034. CBAs were evaluated for target years 2030-2035-2040. In this plan, only two interconnector projects (Nautilus between BE and UK of 1.4 GW capacity and reinforcement between BE and FR Lonny-Achêne-Gramme bringing additional 1 GW capacity) were newly approved. Other projects were investigated without approval. The next revision of the NDP is currently under preparation. The NDP is expected to be formally adopted in 2027 and will cover the period 2028-2038. The CBA's will be evaluated for target years 2035-2040-2050. - only projects with positive CBA are potentially further developed, the other ones remain monitored against the evolution of the energy system/context. In addition, a cross-border identification of system needs study was carried to identify system needs to integrate offshore wind capacity. This KARI study (to be published alongside the 2028-2038 NDP) identifies 0 GW for BE-NL, 4-7 GW for BE-offshore, 1-2 GW for BE-FR and 1-7 GW for BE-LU+DE. Cross border capacity needs differ significantly from needs identified in the EU TYNDP, because TYNDP scenarios are different from the latest national scenarios, because KARI study mostly assesses offshore development and uses topology optimisation and because BE-offshore border is considered.
Bulgaria	Yes	Cross-border capacity needs identified on a national level do not significantly differ from those identified in the EU TYNDP's identification of system needs.
Croatia	No	-
Cyprus	Yes	Cyprus is not interconnected to the EU continental power grid**.**
Czechia	Yes	The TSO uses the results of ENTSO-E's EU TYNDP's Identification of system needs study as a basis for bilateral consultations with the neighbouring TSOs on each interconnection. The identified system needs are subsequently translated into individual grid development projects and evaluated through comprehensive technical and network analyses. These studies are conducted on a bilateral basis for internal planning and decision-making. The NDP includes additional related studies: • Import capacity of the Czech transmission system (ref. to Chapter 5.4 of the CZ NDP 2025 – 2034): The calculation methodology is based on increasing the Czech Republic's import balance in order to identify the technical capabilities of the Czech transmission system while maintaining compliance with the N-1 security criterion. • Capacity evaluation is also performed for selected projects as part of Chapter 6.3 of the CZ NDP 2025 – 2034 "Project Benefits for the Czech Transmission System and the Interconnected European Grid" • Scenarios (ref. to Chapter 5.1 of the CZ NDP 2025 – 2024): Progressive 2030, Contracts 2030, Progressive 2040, Contracts 2040, Nuclear 2040, DE 2040
Denmark	No	-
Estonia	Yes	Electricity infrastructure needs identified amount to 1.7 GW for EE-FI border (of what 1 GW is existing and 0.7 GW needed) by the year 2038 and to 1.6 with Latvia (of what 1 GW is existing and 0.6 GW needed) by year 2035. Results are not different to the EU TYNDP's results.
Finland	No	-
France	Yes	Electricity infrastructure needs identified: Celtic interconnector of 700 MW at FR-IE border (commissioning planned for 2028), Gulf of Biscay interconnector at FR-ES border

	Quantitative assessment of electricity infrastructure needs by the TSO	Additional information

		(commissioning planned for 2028) and 3 GW reinforcement of existing interconnectors at FR-BE and FR-DE borders (2040).
		The TYNDP's IoSN is not directly comparable to the CBAs undertaken before final investment decisions. The IoSN highlights additional interconnection capacity that could generate benefits at a given time horizon under the assumptions and methodology applied. For France, the TYNDP's IoSN identifies an economic potential for 24 GW of additional interconnector capacity by 2040, compared with about 6 GW planned in the French NDP. In the NRA's view, part of this difference may reflect the methodological assumptions inherent in the IoSN framework. Consequently, IoSN results should be interpreted with appropriate caution, considering the following:
		• Investment costs correspond either to figures submitted by project promoters or to estimates derived from unit investment costs. In the current market environment, these assumptions may not fully reflect the actual costs of HVDC converter stations and cables and could therefore lead to an underestimated costs.
		• The socio-economic assessment focuses primarily on aggregated benefits and does not systematically account for their distribution among the countries concerned. As a result, a project generating positive benefits at EU or regional level may not provide a positive balance for each participating country.
		• The analysis does not fully incorporate internal network reinforcements that may be required to accommodate additional cross-border capacity. Interconnectors are therefore assessed on the assumption that the additional capacity can be made available throughout the year without additional internal congestion-management costs.
		• The IoSN monetisation framework considers two additional indicators that warrant particular attention:
		  ○ The added value of interconnectors for security-of-supply may be limited in scenarios where generation mixes already ensure adequate capacity. Moreover, TYNDP results are sensitive to assumptions on generation mixes and capacity availability during peak periods.
		  ○ The TYNDP complements the carbon price already reflected in generation costs with a societal carbon value significantly above projected market price (EUR 628/tCO_2 vs. around EUR 150/tCO_2 in 2040 in TYNDP 2024). Results are therefore sensitive to this valuation assumption.

Germany	No	Projects are proposed where the starting grid shows congestion under scenario assumptions and are evaluated (PINT or TOOT method) based on whether they adequately alleviate congestion. Before the proposal of projects, the TSOs do not estimate the amount of additional capacity needed between two points in the transmission system.
Greece	Yes	The assessment does not structurally deviate from the ENTSO-E's. The values correspond to the expected nominal capacities of the interconnections in the latest approved NDP (NDP 2025-2034). In the latest approved NDP 2025-2034, the following infrastructure needs (in expected nominal capacities) were identified in 2024 for the target year 2035: GR-AL 2085 MW (+1GW), GR-BG 2430 (no change to 2025), GR-MK 1548 MW (no change), GR-TR 2640 MW (+1,44 GW), GR-IT 1500 MW (+1GW), GR-CY 1000 MW (+1GW), GR-EG 3000 MW (+3GW). There is no information about the specific optimization process used by the TSO.
Hungary	Yes	Network capacity needs are studied based on the CORE DA flow-based capacity calculation results when high price spikes and price differentials are observed, as ad-hoc calculations. The methodology is based on re-running the market coupling in the production environment with modified input grid models that contain different possible grid reinforcements. As a result of calculations for 2024 performed in 2025, a 220 kV series reactor in substation Győr is planned to be installed. As the calculations are flow-based, no 'GW per border' value can be defined. Long-term, scenario-based infrastructure needs are assessed through the ENTSO-E TYNDP System Needs Study, which the TSO participates in. It is carried out within the coordinated TYNDP framework rather than as a separate TSO-specific national assessment.
Ireland	No	-
Italy	Yes	The fourth edition of the TSO assessment was published in early 2025 (link). It observes both 2030 (more for regulatory purposes) and 2040 (more for network development purposes). The boundary-by-boundary target capacities are summarised at page 10 of the report. In general, across the years and needs report editions, the ENTSO-E results are different from the national assessment's results. There is no possibility to compare Italy-internal

	Quantitative assessment of electricity infrastructure needs by the TSO	Additional information
		target capacities as ENTSO-E does not publish them. A possible reason of difference, besides the different analytical approach (optimisation vs. iterative approach; definition of capacity-cost candidates) is the categories of benefits considered in the analyses.
Latvia	Yes	Infrastructure needs include 1 GW for LV-EE in 2035 and 0.7 GW for LV-LT interconnectors in 2032 before projects are proposed. Information and conclusions, including forecasts of the development of generating sources and electricity transmission system capacity adequacy, included in the 2024 annual assessment report of the TSO.
Lithuania	Yes	No new assessments of cross-border line capacities have been conducted.
Luxembourg	Yes	The latest version of the "scenario report 2040" published by the TSO (which is about identifying the needs) projects the peak import load to increase from 694 MW in 2023 to between 1900 MW and 3100 MW by 2040. The actual value will likely fall within this range and depend on the rate of adoption of decarbonized technologies, renewable energy integration, and the implementation of flexible solutions. There are three cross-border lines feeding into this aggregate import. There are two interconnectors to Germany that represent currently the primary supply source, and there is also one interconnector to Belgium.
Malta	Not applicable	-
Netherlands	No	-
Norway	No	
Poland	No	-
Portugal	No	-
Romania	Yes	At national level, there is no dedicated process for identifying the need for cross-border interconnection capacity that is methodologically equivalent to the ENTSO-E's IoSN. Within the NDP, the need for the development of cross-border interconnections is assessed mainly by reference to the interconnection objectives and targets established by European legislation in the field of electricity, as well as to the requirements regarding the safe and reliable operation of the national electricity system. By comparison, the European IOSN process aims to identify the optimal level of interzonal transfer capacities from an economic and market integration perspective. It aims to maximize socio-economic benefits at European level by facilitating cross-border exchanges of electricity and by increasing consumers' access to energy sources at the lowest possible cost. The analysis is based on scenarios and assumptions regarding the long-term evolution of the European energy sector and assesses the contribution of infrastructure projects to market integration, the integration of renewable sources and the reduction of the total costs of the energy system. Consequently, the national assessment does not identify and quantify, for each border, the interconnection capacity needs expressed in GW, in the manner used by the IOSN/TYNDP process. The national and European assessments respond to different objectives and use distinct methodological approaches, the two processes being complementary.
Slovakia	No	-
Slovenia	Yes	Information about electricity infrastructure needs (target year 2040) are available here.
Spain	Yes	Capacity and infrastructure needs are identified within the framework of the transmission network development planning process. The planning is based on scenarios aligned with the national energy and climate plan and on technical studies carried out by the TSO regarding the expected evolution of demand, generation, international exchanges and network constraints. The planning process does not include a specific procedure for the prior identification of cross-border capacity needs expressed in GW per border equivalent to ENTSO-E's IoSN approach. Instead, taking the indicative forecasts as a starting point, these needs are derived from the planning studies and from the assessment of the measures required in the transmission network and interconnections. However, the ENTSO-E IoSN indicates that by 2030, additional cross-border capacity of approximately: 1 GW at the border with Portugal and 5 GW with the rest of the European System and by 2050 indicates 2 GW at the border with Portugal and 8 GW with the rest of the European System. Based on the proposed NDP 2025-2030, interconnection needs 2030 beyond Biscay Gulf interconnection (commissioning date: 2028) include 1 GW for ES-PT and 5 GW for the

	Quantitative assessment of electricity infrastructure needs by the TSO	Additional information
		rest of Europe. For 2050, interconnection needs amount to 2 GW for ES-PT and 8 GW for the rest of Europe. Based on identified needs, the following network expansion is planned: • Around 9.500 km of network affected (≈21%), including: • ~6.000 km upgrading of circuits • ~1.470 km new conductors • ~336 km with Dynamic Line Rating (DLR) • ~1.800 km renewal of transmission lines
Sweden	No	-

Source: NRAs data provision in 2026

D. Comparison of congestion income and EU TYNDP infrastructure needs

The analysis compares congestion income reported by NRAs for the period between 2023 and 2025 with the cross-border infrastructure needs identified in the EU TYNDP 2024 for 2040[36]. The objective is to assess whether the EU TYNDP infrastructure needs assessment identifies opportunities for additional cross-border capacity where transmission-level congestions have been observed in recent years.

Data preparation and harmonisation

EU TYNDP 2024 infrastructure needs are generally expressed as cross-border network capacity ranges. For the purpose of this analysis, the average of each range was used as the representative infrastructure need value. For open-ended ranges with an infinite upper bound, the lower bound was used instead.

Congestion income is reported at bidding-zone borders, whereas EU TYNDP 2024 infrastructure needs are primarily identified at country borders. The two datasets were therefore harmonised to enable comparison.

Limitations

Congestion income is only reported for existing interconnections. Consequently, infrastructure needs related to entirely new cross-border interconnections, for which no congestion income is available, are excluded from the comparison.

For some borders, congestion income data was available from only one side of the border[37]. Where data was available from both sides, the reported values were summed to obtain a single congestion income value for that border. To ensure representativeness and comparability, the results are presented on two Figures, separately for borders where congestion income is available from both sides and those where it is available from only one side.

In some cases, part or all of the congestion income could not be uniquely allocated to individual borders (for example, for borders subject to flow-based capacity calculation in the CORE capacity calculation region). As this income could not be attributed to specific borders, it has been excluded from the border-level comparison. Borders that may be significantly affected by the unallocated congestion income are highlighted in orange in the figures.[38] For these borders, the reported congestion income should therefore be interpreted with caution, as it excludes income that could not be assigned to a specific border and may consequently understate the actual level of congestion.

[36] The analysis uses the EU TYNDP 2024 system needs for 2040 accessed on 19 June 206 on ENTSO-E's website.
[37] For example, obligation to report congestion income applies for EU-EU borders.
[38] A border is highlighted where congestion income could not be allocated to specific borders and the average yearly amount of such unallocated income exceeded 10 million EUR.

Table 8: Congestion income data in 2023, 2024 and 2025 split per border provided by the NRAs

Member state	Border	2023	2024	2025
AT	AT - CH	NAP	42.2	37.7
	AT - CZ	26.1	9.1	19.0
	AT - DE_LU	153.5	0.0	25.6
	AT - HU	22.3	37.8	37.7
	AT - IT_NORTH	17.8	32.8	35.6
	AT - SI	18.2	15.4	22.4
	Other[39]	20.0	35.1	66.4
BE	BE - DE_LU	53.2	20.6	24.6
	BE - FR	150.7	40.9	125.2
	BE - NL	57.6	24.4	28.1
	Other[40]	27.0	40.5	
BG	BG - GR	92.0	70.6	54.7
	BG - NMK	8.0	6.4	5.0
	BG - RO	33.0	15.6	23.7
	BG - RS	17.0	12.2	10.8
	BG - TR	30.0	20.7	24.2
CZ	AT - CZ	32.9	20.2	29.4
	CZ - DE_LU	51.7	47.6	61.6
	CZ - PL	16.2	25.0	22.1
	CZ - SK	43.2	65.2	68.7
	Other			6.1[41]
DE	AT - DE_LU	321.5	192.3	274.9
	BE - DE_LU	57.3	20.8	24.6
	CH - DE_LU	108.1	115.0	161.1
	CZ - DE_LU	37.4	29.6	41.3
	DE_LU - DK1	117.2	106.5	123.9
	DE_LU - DK2	36.7	32.6	28.2
	DE_LU - FR	271.7	80.1	150.3
	DE_LU - NL	121.5	51.1	49.3
	DE_LU - NO2	110.0	139.4	138.3
	DE_LU - PL	0.0	0.0	0.2
	DE_LU - SE4[42]	80.2	65.2	60.1
	Other[43]	216.5	213.0	370.1
DK	DE_LU - DK1	92.4	85.0	106.2
	DE_LU - DK2	17.3	25.4	21.3
	DK1 - UK	0.8		
	DK1 - DK2	56.6	28.2	18.3

[39] CI from AT-SLACK calculated under the CACM CID methodology.
[40] Implicit congestion rents, CI from flow-based daily capacity auction.
[41] CI from balancing platforms.
[42] Corresponding to 50% of CI from Baltic Cable AB calculated by ACER for 2023 and 2024.
[43] Includes CI from MARI and PICASSO (balancing timeframe) and the Core-region (CI from the Day-Ahead and Intraday timeframes is consolidated in a common pot).

Member state	Border	2023	2024	2025
	DK1 - GB		85.8	105.7
	DK1 - NL	42.0	29.7	22.3
	DK1 - NO2	85.9	143.1	122.8
	DK1 - SE3	44.0	78.0	89.0
	DK2 - SE4	91.8	112.1	98.4
EE	EE - FI	105.6	165.7	165.0
	EE - LV	23.7	14.1	23.9
ES	ES - FR	679.6	373.7	350.4
	ES - PT	21.0	22.5	28.8
FI	EE - FI	202.0	163.0	171.4
	FI - NO4		0.0	1.6
	FI - SE1	77.8	95.9	111.0
	FI - SE3	37.1	67.3	66.6
	Other[44]		1.4	-1.3
FR	ES - FR	679.7	365.3	345.0
	FR - IT_NORTH	688.9	748.5	969.2
	Other[45]	571.0	471.6	736.1
GR	AL - GR	20.7	10.8	12.1
	BG - GR	91.5	70.6	54.7
	GR - IT_SOUTH	63.8	79.6	53.1
	GR - NMK	24.6	17.8	16.1
	GR - TR	22.5	11.0	17.1
HR	BA - HR	6.3	9.9	7.8
	HR - HU	14.9	8.4	17.2
	HR - RS	7.5	15.2	13.3
	HR - SI	9.8	8.2	13.7
	Other[46]	20.2	45.0	27.4
HU	AT - HU	34.9	71.0	58.1
	HR - HU	21.0	18.0	24.8
	HU - RO	29.8	23.9	26.3
	HU - RS	47.3	15.3	18.4
	HU - SI	11.9	19.6	18.6
	HU - SK	37.9	59.8	72.9
	HU - UA		15.5	24.4
	Other[47]	8.7	11.6	8.1
IT	AT - IT_NORTH	37.2	66.4	51.4
	CH - IT_NORTH	270.6	316.3	243.9
	FR - IT_NORTH	673.6	735.3	962.5
	GR - IT_SOUTH	63.8	79.6	52.4

[44] Includes CI related to flow-based resettlement and changes in resettlement.
[45] Includes CI from CWE region (BE-DE and DE_LU-FR) and Core region (BE-FR and DE_LU-FR) and TERRE platform.
[46] Includes CI from Core Day-ahead and Intraday market coupling, including the Polish allocation constraint (PLAC), that cannot be allocated by border.
[47] Includes congestion income from DACI slack hubs, DACI spanning hours per hub, and PSE PL AC.

Member state	Border	2023	2024	2025
	IT_CALA - IT_SICILY			10.9
	IT_CALA - IT_SOUTH			5.0
	IT_CENTRE_NORTH - IT_CENTRE_SOUTH			23.4
	IT_CENTRE_NORTH - IT_NORTH			28.3
	IT_CENTRE_SOUTH - IT_SARDINIA			26.3
	IT_CENTRE_SOUTH - IT_SOUTH			36.7
	IT_CENTRE_SOUTH - ME	47.9	40.1	31.4
	IT_NORTH - SI	92.3	74.8	70.3
	Other[48]	169.1	166.9	8.3
LT	LT - LV	2.5	0.6	1.6
	LT - PL	32.9	28.9	23.2
	LT - SE4	73.1	105.3	66.7
	Other			8.2[49]
LV	EE - LV	9.4	7.2	16.3
	LT - LV	2.6	0.6	1.6
	Other[50]	21.9	6.2	13.5
NL	BE - NL	85.4	64.8	63.5
	DE_LU - NL	150.6	75.3	84.8
	DK1 - NL	60.4	45.1	37.9
	NL - NO2	48.1	77.8	52.0
	Other[51]	2.8	8.3	26.2
PL	Other[52]	192.6	208.9	235.6
	PL - UA_IPS	0.8	4.9	6.8
PT	ES - PT	15.1	11.5	19.3
RO	BG - RO	29.6	12.5	14.5
	HU - RO	35.0	34.3	32.8
	MD - RO		1.5	3.0
	RO - RS	4.3	2.2	7.0
	RO - UA	0.2	6.3	9.6
	RO - UA_IPS	0.3		
SE	DE_LU - SE4[53]	80.5	65.5	60.5
	DK1 - SE3	72.5	78.2	95.9
	DK2 - SE4	93.1	112.4	107.2
	FI - SE1	77.0	95.9	112.1
	FI - SE3	37.4	67.3	65.4
	LT - SE4	73.6	105.3	66.9
	NO1 - SE3	55.0	36.7	84.3

[48] Includes CI from internal rents on virtual zones.
[49] Includes CI from balancing platforms (MARI and PICASSO) and the capacity market.
[50] Includes CI from liquidation of congestion overloads, PTR limited auctions, MARI, PICASSO and BBCM.
[51] Includes other financial income and costs related to internal account balances, overhead costs related to the management of the internal account, and repayments of amounts previously withdrawn from congestion revenues.
[52] Includes CI from Core borders (CZ-PL, SK-PL and DE-PL) and non-Core borders (SE4-PL and LT-PL), covering day-ahead, intraday and, where applicable, long-term markets, as well as from the capacity market and balancing platforms.
[53] 50% of CI collected by Baltic Cable AB, calculated by ACER for 2023 and 2024.

Member state	Border	2023	2024	2025
	NO3 - SE2	15.7	11.6	14.3
	NO4 - SE1	21.1	11.7	12.0
	NO4 - SE2	4.2	3.9	3.7
	PL - SE4	93.8	63.8	93.2
	SE1 - SE2	0.1	13.4	58.7
	SE2 - SE3	663.3	642.9	1,514.1
	SE3 - SE4	457.3	497.5	468.5
SI	AT - SI	29.0	41.8	41.9
	HR - SI	20.3	30.6	24.9
	HU - SI	11.8	19.4	18.4
	IT_NORTH - SI	92.9	75.3	70.9
	Other[54]	35.7	102.7	119.2
SK	CZ - SK	24.4	26.4	37.7
	HU - SK	24.8	18.7	40.4
	Other			19.7
	PL - SK	24.4	16.5	22.8
	SK - UA	2.4	15.9	11.2

Note: Category 'other' indicates congestion income that could not have been split per borders.

Source: ACER data collection from NRAs.

E. Grid enhancing technologies in electricity network development planning

Table 9: Grid enhancing technologies in electricity network development planning

	Consideration in the network planning process	Types of GETs considered	Regulatory measures or incentives	Inclusion of GETs projects in the most recent (final or draft) NDP
Austria	Explicit requirement[55]	DLR[56]	Dedicated financial incentive (TSO)[57]	DLR
Belgium	Explicit requirement	DLR, HTLS[58]	Dedicated financial incentive (TSO)[59]	HTLS[60]
Bulgaria	No	-	No	-
Croatia	Yes	DLR	No	DLR

[54] Includes CI allocated to the Core slack hub (slack zone), arising from flow-based capacity allocation.
[55] AT: the national law envisages that construction of new lines will only be considered after the existing lines have been sufficiently optimized or appropriate reinforcement and expansion measures have been carried out.
[56] AT: GET's capacities are considered in the planning/modelling assumptions.
[57] AT: The TSO regulation foresees an incentive component for implementing smart operational or digital measures that measurably lower costs for grid users compared to standard alternatives. Operators receive a yearly bonus equal to half of the net economic benefit generated by these measures, provided they clear a specific cost threshold and receive regulatory approval based on a structured cost-benefit analysis.
[58] BE: Dynamic line rating and HTLS are structurally envisaged in the network development process. Moreover, Smart network maintenance processes, based on real & measured Wear & Tear have been developed by the TSO. Capacity gains of HTLS are considered in future scenarios and in allocating capacities to network users. For DLR, the capacity gains do not influence future scenarios and are only used for operational grid optimisation
[59] BE: The federal regulatory regime for electricity transmission foresees several output based incentives. The Innovation Incentive specifically targets innovative solution for a more efficient network, including GETs and non-CAPEX solutions.
[60] BE: The use of DLR is cited in a generic way in the NDP.

	Consideration in the network planning process	Types of GETs considered	Regulatory measures or incentives	Inclusion of GETs projects in the most recent (final or draft) NDP
Cyprus	Yes	Synchronous condensers with flywheels[61]	No	No inclusion in NDP
Czechia	Yes	DLR[62]	No	DLR
Denmark	Yes	DLR, Cyclic transformer rating, PST, System Integration Protection Schemes[63]	No	Short term rating of branch components
Estonia	No		No	No inclusion in NDP
Finland	Explicit requirement	DLR[64], STATCOM	Monitoring[65]	DLR, STATCOM
France	Explicit requirement	DLR, load flow management system	Dedicated financial incentive (TSO and DSO)	DLR, Load flow management system (New Adaptive Zone Controller)
Germany	Explicit requirement[66]	DLR[67], HTLS, load flow management (e.g. PST and HVDC optimisation)	No	DLR, Load flow management (e.g. PST and HVDC optimisation)
Greece	Yes	DLR, FACTS, PSTs	No	FACTS and DLR (as pilot)
Hungary	Explicit requirement	DLR	No	DLR
Ireland	Yes	DLR	Dedicated financial incentive (TSO)[68]	DLR

[61] CY: No actual implementation or inclusion in the latest approved TYNDP.
[62] CZ: Depending on prevailing weather conditions, DLR can increase the current-carrying capacity (ampacity) of transmission lines by up to 30%.
[63] DK: DLR and cyclic transformer rating are used to obtain additional capacity for demand or generation for areas that are heavily constrained by a single or few branch components' ampacity (e.g., a HVAC UG cable). Phase shifting transformers are used in various scenarios to mitigate overloading during outages. System Integration Protection Schemes (SIPS) are used for certain outages to mitigate or counter potential overloading (by adjusting power transfer of HVDC links or by curtailing certain renewables depending on the location/outage).
[64] FI: The TSO will monitor the use of DLR and further develop the operating model as part of the long-term development of the transmission grid.
[65] FI: The NRA has introduced new indicator to monitor the length of transmission lines using dynamic line rating, average static thermal transmission capacity and average thermal transmission capacity. In addition, NRA has also started monitoring transmission compensation equipment, including the installed capacitive and inductive compensation capacity.
[66] DE: The TSOs must adhere to the NOVA principle, meaning Optimisation, like through GETs, has to be considered before Reinforcement of existing lines, before the construction of new ones.
[67] DE: DLR is used for every project in the NDP.
[68] IE: the Investment Planning Delivery incentive in Price Review 5 requested the TSO to demonstrate the consideration of non-wire solutions in the investment and planning process. The main technologies considered are Dynamic Line Rating and Power Flow Controllers. Additionally, in Price Review 5/Price Review 6, the TSO and TAO are incentivised, through the joint TSO/TAO incentive, in trialling, piloting and deploying new technology. Assessment is based on outturn performance against planned deliverables and the annual submission of a technology toolbox report which categorises and describes progress for all new technologies considered by the TSO/TAO.

	Consideration in the network planning process	Types of GETs considered	Regulatory measures or incentives	Inclusion of GETs projects in the most recent (final or draft) NDP
Italy	Yes	PSTs, reconductoring[69]	Indirect output-based incentive (TSO)[70]	PST, reconductoring
Latvia	No	-	No	-
Lithuania	Yes	DLR	No	DLR
Luxembourg	Yes	HTLS	No	HTLS
Malta	NAP	NAP	NAP	NAP
Netherlands	Yes	DTR (including DLR), E-STATCOMs, synchronous condensers, load flow management (e.g. PST and HVDC optimisation)	No	DLR, Synchronous condensers, PSTs
Norway	Yes	DLR	R&D Scheme	DLR. These are included in the development plans.
Poland	No	-	No	-
Portugal	No		Indirect incentive (TSO)[71]	-
Romania	Yes	DLR	No	DLR
Slovakia	Yes	DLR[72]	No	DLR, PST, HTLS
Slovenia	Explicit requirement	DLR, PSTs, Statis Synchronous Series Compensators, HTLS	Dedicated financial incentive (TSO and DSO)[73]	DLR, SSSC, HTLS, PST

[69] IT: The network development plan includes some type of projects (e.g. local ampacity increases by tailored interventions, reconductoring, phase shifters) but does not include other types (such as dynamic line rating). Planned projects are subject to benefit analysis if they pass the NDP CAPEX-threshold for CBA.
[70] IT: incentive for inter-zonal capacity increases combined with a CAPEX-efficiency incentive.
[71] PT: Currently there is no explicit incentive to develop and use GETs. However, TOTEX regulation currently in place for the transmission network is expected to implicitly incentivise the TSO to invest in the efficient use of the network, namely through GETs.
[72] The Slovak TSO systematically evaluates grid enhancing technologies within its Network Development Plan (NDP) framework to optimize grid flexibility before moving to traditional, asset-heavy infrastructure investments. The primary GET considered and actively prepared is DLR. DLR is integrated into the planning phase through advanced network models and meteorological simulation data to assess how changing environmental factors (temperature, wind speed) can safely unlock temporary transmission capacity margins. Potential capacity gains are assessed using offline alternating current load-flow simulations to ensure that utilizing higher line ratings on specific cross-border or internal profiles does not cause downstream bottlenecks or compromise N-1 security criteria.
[73] SI: The Regulatory Act on the Methodology for Establishing the Regulatory Framework for Electricity Operators sets forth several types of incentives for the use of GETs, namely: (1) Regulation based on the performance of investments in smart grids, based on smart grids performance indicators; (2) Covering the costs of research and innovation for eligible projects that address innovative examples of smart grids, cross-sector integration, better utilization of the existing grid, integration of RES, etc. (3) promoting investment in smart grids through a time-limited financial incentive, one-time incentives for project success or one-time financial incentives based on benefit-sharing.

	Consideration in the network planning process	Types of GETs considered	Regulatory measures or incentives	Inclusion of GETs projects in the most recent (final or draft) NDP
Spain	Explicit requirement	DLR, FACTS, PSTs, SSSC, Other	Dedicated financial incentive (TSO)[74]	DLR, FACTS, Load flow management (overload line controller), PSTs
Sweden	Yes	DLR, controllable power flow devices, FACTS, HTLS, Other[75]	No	controllable power flow devices, FACTS, HTLS

Source: NRAs data provision in 2026

F. Delays in the EU TYNDP planning process

Table 10: Delays in delivery of key EU TYNDP milestones and time between project submission and TYNDP publication (months)

TYNDP cycle		2018	2020	2022	2024	2026	Average
Delay in scenarios		6	9	4	8	3	6
Electricity	**EU TYNDP delay**	1	4	2	6	-	3
	Time between project submission deadline and draft EU TYNDP delivery	14	15	15	18	-	16
Gas	**EU TYNDP delay**	7	9	8	13	-	9
	Time between project submission deadline and draft EU TYNDP delivery	15	8	18	23	-	16

Note: Delays were calculated as the difference between the planned delivery dates (as typically set out in the applicable work programmes) and the actual submission dates to ACER.

[74] ES: The remuneration framework established by Circular 5/2019 (revised in 2025) encourages the deployment of solutions such as DLRs by prioritising grid optimisation (the new technologies are remunerated at audited costs without adjustments, unlike traditional technologies subject to adjustments based on reference unit values). In addition, GETs have (1) recognised asset categories, which facilitates their remuneration and improves regulatory certainty, (2) shorter regulatory lifetime, which allows costs to be recovered sooner with lower risk and (3) lower investment costs, this help companies remain within the maximum annual investment cap set by regulation and therefore avoiding penalties for overspending.

[75] SE: For example, the TSO estimates that the conservative thermal limits currently applied to overhead lines may underestimate the available transmission capacity by approximately 20–30% under normal operating conditions. DLR is therefore being evaluated as a means to optimise the utilisation of the existing transmission grid, facilitate earlier customer connections and increase the capacity made available to the electricity market while new infrastructure is being developed.

G. Supply chain issues and measures against them

Table 11: Supply chain issues and measures against them

		Countries
Supply chain issues[76]	Long lead times	AT (especially for transformers), BE (DC components, transformers, shunt reactors), CZ, DK[77] (electricity), GR (electricity), HU[78], IT (electricity), LT[79], LU, PL (especially autotransformers, shunt reactors, surge arresters, CT/VT transformers), RO[78], SK (electricity and gas; transformers, circuit breakers, insulators), SI (electricity)
	Increased prices	BE (gas, hydrogen), DK (electricity), ES, GR (electricity), IT (electricity), LT, LU
	Skilled workforce	DK, PL
	Grid-specific standards	GR, HU
Measures against supply chains	Diversification	BE (electricity), GR, SK
	Standardisation	BE (electricity), FR (electricity)
	Long-term contracts or partnership with equipment suppliers	CZ, DK, FR (electricity), GR, IE, MT, PL, SK
	Market dialogue	DK, MT
	Monitoring[80]	DK, GR, HU, MT
	Adjusted planning (incl. prioritisation, conservative approaches, earlier procurement)	DK, HU, IT[81], MT, RO, SI
	Equipment inventory	EE, IE, LU, SK, SI
	Equipment design optimisation or alternative technology	DE
	Cost recognition by the NRA	ES
	Centralised procurement	LT

[76] Germany and the Netherlands also reported supply chain issues, but did not further specify them. Germany highlighted challenges related to offshore converters and cable-laying vessels.
[77] In Demark, delivery times for key grid components have increased from months to several years.
[78] In Hungary and Romania, delivery times have in some cases doubled or, in Romania, quadrupled.
[79] In Lithuania, lead times for high-voltage power line and substation equipment increased by 50-100% compared to 10 years ago, with lead times being more volatile and less predictable.
[80] For example, monitoring of delivery schedules, suppliers through KPIs, strategic reserves, lead times, pricing trends and supplier capacity.
[81] In Italy, the TSO reworked the timeline of NDP projects to prioritise the most urgent.

H. Congestion income

Table 12: Total congestion income available, 2023-2025, at EU level (million EUR)

Year	CI collected	Separate account from previous years[82]	Adjustment due to provisional data	Total
2023	9,475.88	9,128.24	16.02	18,620.14
2024	8,383.19	8,612.99	23.64	17,019.82
2025	10,369.60	10,714.94	-1.41	21,083.13

Source: ACER data collection from NRAs.

Note 1: The total congestion income in the EU includes data from 23 Member States. Cyprus, Ireland, Luxembourg and Malta are not required to submit reports, as no congestion income is collected in their territory or at EU borders.

Note 2: For the analysis, the total 'congestion income (CI) available' is based on the data categories collected by ACER. This figure is calculated as the sum of the following categories, as reported by each Member State:

- *'CI collected': congestion income generated at EU-EU borders including amounts generated at internal bidding zones (which can account for high figures). The CI collected arises from allocating capacity in the single day-ahead, intraday and balancing frames, as well as from long-term transmission rights.*
- *'CI stored in a separate internal account line': amounts of CI generated at EU-EU or internal bidding zones borders from previous years that were not used and thus stored in a separate internal account line for future use (account balance at the beginning of the reporting year). The CI stored in a separate internal account line may be overstated in some countries, as it includes CI generated across all borders where it was not possible to distinguish between EU-EU and EU-non-EU borders.*
- *'Adjustment': applicable country-specific adjustments due to provisional data.*

Further details are provided in Table 13 below.

Table 13: Congestion income available, 2023-2025, per Member State (million EUR)

Country[83]	Year	CI collected	Separate account from previous years	Adjustment due to provisional data	Total
Austria	2023	258.00	94.99	NAP	**352.98**
	2024	130.11	144.37	NAP	**274.47**
	2025	207.21	127.50	NAP	**334.72**
Belgium	2023	288.52	NAP	NAP	**288.52**
	2024	126.40	NAP	NAP	**126.40**
	2025	177.51	0		**177.51**
Bulgaria	2023	125.00	74.8	0	**199.80**
	2024	86.20	67.40	NAP	**153.60**
	2025	78.36	108.10	NAP	**186.46**
Croatia	2023	44.89	0	NAP	**44.89**
	2024	61.56	25.60	-0.13	**87.03**
	2025	58.32	51.71	0.12	**110.15**
Czechia	2023	143.95	150.57	0	**294.52**
	2024	158.02	182.21		**340.23**
	2025	187.88	212.80	0	**400.68**
Denmark[84]	2023	344.00	385.40	NAP	**729.40**
	2024	358.26	465.10	0	**823.36**
	2025	355.31	652.46		**1,007.77**
Estonia	2023	129.37	268.85	NAP	**398.22**
	2024	179.80	338.95	NAP	**518.75**

[82] Internal account line balance at the beginning of the reporting year reflecting amounts of CI stored from previous years.
[83] The CI data collection covers 23 Member States. Cyprus, Ireland, Luxembourg and Malta are not required to report, as no congestion income is collected in their territory or at EU borders.
[84] DK: 'CI stored in a separate internal account line' figures include CI originating from all borders, as it was not possible to distinguish between CI originating from EU-EU and EU-non-EU borders.

Country[83]	Year	CI collected	Separate account from previous years	Adjustment due to provisional data	Total
	2025	189.11	336.70	NAP	**525.81**
Finland	2023	317.00	1,063.70	NAP	**1,380.70**
	2024	327.50	975.70	NAP	**1,303.20**
	2025	347.70	841.80[85]	NAP	**1,189.50**
France	2023	1,939.60	NAP	NAP	**1,939.60**
	2024	1,585.50	NAP	NAP	**1,585.50**
	2025	2,050.30	NAP	NAP	**2,050.30**
Germany	2023	1,340.11	98.95	NAP	**1,439.06**
	2024	856.41	377.89	NAP	**1,234.30**
	2025	1,123.00	445.57	NAP	**1,568.57**
Greece	2023	155.28	78.15	-1.61	**231.82**
	2024	150.15	90.04	0.36	**240.55**
	2025	107.74	99.81	-1.24	**206.31**
Hungary	2023	144.06	189.82	0	**333.88**
	2024	203.97	173.26	0	**377.22**
	2025	208.70	160.11	0	**368.81**
Italy	2023	1,035.95	NAP	NAP	**1,035.95**
	2024	1,122.81	NAP	NAP	**1,122.81**
	2025	1,275.50	NAP	NAP	**1,275.50**
Latvia	2023	33.86	92.43	0	**126.28**
	2024	14.01	95.83	-1.59	**108.25**
	2025	31.39	79.58	NAP	**110.97**
Lithuania	2023	108.53	351.50	NAP	**460.03**
	2024	134.90	299.34	0	**434.24**
	2025	99.68	390.12	0	**489.80**
Netherlands	2023	299.30	28.20	0	**327.50**
	2024	193.50	159.80	NAP	**353.30**
	2025	212.50	273.60	NAP	**486.10**
Poland	2023	192.50	410.10	0	**602.60**
	2024	208.90	524.80	NAP	**733.70**
	2025	235.56	604.13	NAP	**839.69**
Portugal	2023	15.11	0	0	**15.11**
	2024	11.45	0.92	0	**12.37**
	2025	19.33	7.29	0	**26.62**
Romania	2023	64.61	30.73	2.35	**97.69**
	2024	46.74	67.41	0	**114.15**
	2025	47.28	34.62	0	**81.90**
Slovakia	2023	73.63	46.05	15.28	**134.96**
	2024	84.38	58.08	NAP	**142.46**
	2025	120.56	85.09	-0.11	**205.52**
Slovenia	2023	154.03	0	0	**154.03**
	2024	269.81	0	0	**269.81**
	2025	275.49	0	0	**275.49**
Spain	2023	700.6	28.00	NAP	**728.60**
	2024	396.12	328.60	25.00	**749.72**
	2025	379.17	318.84	-0.18	**697.83**
Sweden[86]	2023	1,568.00	5,736.00	NAP	**7,304.00**
	2024	1,676.70	4,237.70	NAP	**5,914.40**

[85] FI: 'CI stored in a separate internal account line' figure in 2025 include CI originating from all borders, as it was not possible to distinguish between CI originating from EU-EU and EU-non-EU borders.
[86] SE: The CI stored in a separate internal account line could not be distinguished between income from only EU-EU borders and EU-non-EU borders (Sweden-Norway). Hence, the value on the separate internal account line also includes CI collected at non-EU borders. CI allocated to Baltic Cable AB is not included in the figures for SE reported in this table.

Country[83]	Year	CI collected	Separate account from previous years	Adjustment due to provisional data	Total
	2025	2,582.00	5,885.10	NAP	**8,467.10**

Source: ACER data collection from NRAs.

Note: discrepancies may exist between the sum of the amounts reported for individual bidding zone borders and the total amount reported as collected per Member State, due to differences in reporting practices.

Table 14: Expenditure and carry-over evolution at EU level (million EUR)

	Priority objectives[87]	Placed in a separate internal account line[88]	Tariff reduction	Taxes on saved CI	Electricity customers support[89]
2023	5,301.06	8,551.69	2,201.72	122.77	2,465.27
2024	5,471.87	10,512.33	1,030.46	87.43	35.88
2025	6,792.52	12,462.86	1,694.93	190.58	NAP

Source: ACER data collection from NRAs.

Note 1: For the 2025 reporting period, the indicator 'Surplus CI spent for electricity customer support' was removed from the questionnaire, as the derogation introduced pursuant to Article 9 of Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices is no longer in application.

Note 2: The total congestion income expenditure in the EU includes data from 23 Member States. Cyprus, Ireland, Luxembourg and Malta are not required to submit reports, as no congestion income is collected in their territory or at EU borders.

Note 3: The aggregate amounts also include countries whose expenditure figures cover congestion income generated at all borders, where it was not possible to distinguish congestion income derived from EU–EU borders only (for example, Denmark, Finland and Sweden in 2025). For more information, see Table 15 below.

Table 15: Expenditure and carry-over breakdown, 2023-2025 per Member State (million EUR)

Country	Year	Priority objectives	Placed in a separate internal account line (account balance at the end of the year)	Tariff reduction	Taxes on saved CI	Electricity customer support
Austria	2023	225.50	127.48	NAP	NAP	NAP
	2024	170.73	103.74	NAP	NAP	NAP
	2025	207.23	127.49	NAP	NAP	NAP
Belgium	2023	288.52	0	0	0	0
	2024	126.40	0	0	0	0
	2025	177.51	0			NAP
Bulgaria	2023	132.4	67.4	0	0	0
	2024	45.50	108.10	0	NAP	NAP
	2025	115.38	71.08	NA	NA	NAP
Croatia	2023	19.29	25.6	0	NAP	0
	2024	35.31	51.71	0	0	0
	2025	25.96	84.19	0	0	NAP
Czechia	2023	51.61	182.21	0	60.69	0
	2024	81.59	212.80		45.84	
	2025	77.67	251.57	0	71.44	NAP

[87] Article 19(2) of Regulation (EU) 2019/943 identifies priority objectives for the use of CI such as guaranteeing the actual availability of the allocated capacity including firmness compensation or maintaining or increasing cross-zonal capacities. According to Article 19(3) of the same Regulation, where the priority objectives have been adequately fulfilled, the CI may be used for calculating network tariffs. The use of congestion income in accordance with these objectives is subject to a methodology proposed by the transmission system operators ('UCI Methodology'), which was approved by ACER in December 2020. See ACER Decision No 38/2020 on the methodology for the use of congestion (and its Annex).

[88] Separate internal account line balance at the end of the reporting year.

[89] 'Electricity customer support' refers to CI expenditure related to support electricity customers, pursuant to Article 9 of Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices. Article 9 allowed Member States, by way of derogation from the applicable Union rules on congestion income, to use surplus revenues resulting from the allocation of cross-zonal capacity to finance measures in support of final electricity customers, subject to approval by the relevant national regulatory authority. Regulation (EU) 2022/1854 applied until 31 December 2023.

Country	Year	Priority objectives	Placed in a separate internal account line (account balance at the end of the year)	Tariff reduction	Taxes on saved CI	Electricity customer support
Denmark[90]	2023	114.40	461.60	145.60	22.40	72.10
	2024	288.73	652.48	67.11	-2.89	0
	2025	260.30	672.11	0	75.36	NAP
Estonia	2023	59.26	338.95	NAP	NAP	NAP
	2024	177.93	336.70	4.12	NAP	NAP
	2025	174.00	278.37	73.44	NAP	NAP
Finland	2023	120.3	975.7	284.7	NAP	NAP
	2024	160.40	841.80	301.00	NAP	NAP
	2025[91]	311.70	797.50	81.90	NAP	NAP
France	2023	1,173.20	NAP	766.40	NAP	NAP
	2024	1,376.60	NAP	208.90	NAP	NAP
	2025	1590.00	NAP	459.00	NAP	NAP
Germany[92]	2023	900.80	377.90	0	NAP	NAP
	2024	658.32	445.57	0	NAP	NAP
	2025	1,203.16	305.29	0	NAP	NAP
Greece	2023	92.24	92.99	46.59	0	0
	2024	81.30	91.56	67.69		
	2025	55.61	99.11	51.59	NAP	NAP
Hungary	2023	58.88	179.30	95.70	0	0
	2024	125.03	161.24	90.95	0	0
	2025	85.58	201.50	81.73	0	NAP
Italy	2023	1,035.95	NAP	NAP	NAP	NAP
	2024	1,122.81	NAP	NAP	NAP	NAP
	2025	1,275.50	NAP	NAP	NAP	NAP
Latvia	2023	16.33	97.42	12.54	NAP	NAP
	2024	22.50	79.58	4.49	NAP	NAP
	2025	21.84	43.69	45.45	NAP	NAP
Lithuania	2023	18.38	299.30	142.30	NAP	NAP
	2024	44.08	390.78	0	NA	0
	2025	55.65	399.68	34.47	0	NAP
Netherlands	2023	167.7	159.8			
	2024	79.60	273.60	0	0	0
	2025	72.30	253.80	160.00	0	NAP
Poland	2023	80.80	490.40	0	31.50	0
	2024	82.40	618.80	NAP	32.50	NAP
	2025	91.70	710.82	NAP	37.16	NAP
Portugal	2023	14.33	0.78	0	0	0
	2024	5.28	7.29	0	0.23	0
	2025	9.68	16.93	0	0	NAP
Romania	2023	8.25	67.79	13.46	8.18	0
	2024	39.43	35.09	0	1.35	38.28
	2025	21.21	54.08	0	6.62	NAP
Slovakia	2023	3.25	58.08	73.63	0	0
	2024	2.60	85.09	44.37	10.39	0
	2025	30.92	54.07	120.54	0	NAP
Slovenia	2023	106.86	0	0	0	47.17
	2024	131.08	0	138.73	0	0
	2025	104.473	0	171.018	0	NAP
Spain	2023	279.81	328.00	105.80	NAP	15.00
	2024	430.74	319.00	0	0	NAP
	2025	365.04	332.79	0	0	NAP
	2023	333.00	4,221.00	515.00	NAP	2,331.00

[90] DK: Expenditure and carry-over figures include CI originating from all borders, as it was not possible to fully distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders.
[91] FI: Expenditure and carry-over 2025 figures include CI originating from all borders, as it was not possible to distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders.
[92] DE: The sum does not equally match the overall congestion income inputs because the use of congestion income by Baltic Cable is not presented in the expenditure and carry-over figures.

Country	Year	Priority objectives	Placed in a separate internal account line (account balance at the end of the year)	Tariff reduction	Taxes on saved CI	Electricity customer support
Sweden[93]	2024	183.50	5,697.40	103.10	NAP	-2.40
	2025	460.10	7,708.80	415.80	NAP	NAP

Source: ACER data collection from NRAs.

Table 16: Evolution of priority objectives expenditure, 2023-2025 (million EUR)

Year	System operation costs	Network investments	Total expenditure
2023	3,394.66	2,018.48	5,413.14
2024	3,853.99	2,092.46	5,946.45
2025	4,267.52	2,894.90	7,162.42

Source: ACER data collection from NRAs.

Note 1: The priority objectives expenditure includes data from 23 Member States. Cyprus, Ireland, Luxembourg and Malta are not required to submit reports, as no congestion income is collected in their territory or at EU borders. The two cost categories have been calculated following the classification of costs contributing to the priority objectives set out in Article 3 of the Use of Congestion Income Methodology in accordance with Article 19(4) of Regulation (EU) 2019/943.

Note 2: The total amounts are overstated, as also includes expenditures from countries whose expenditure figures comprise CI generated at all borders, where it was not possible to distinguish CI derived from EU-EU borders only..

Table 17: EU expenditure on priority objectives, by cost category, 2025 (million EUR)

Cost category	Definition	Value
i	Cost related to **firmness measures** that guarantee cross-zonal schedules resulting from firm allocated capacity and costs related to **remedial actions** activated to maximise available capacity for cross-zonal trade.	1,607.69
ii	**Firmness compensation costs** (compensation of owners of curtailed transmission rights).	63.92
iii	**Financial net costs** associated to hedging options.	151.88
iv	Remuneration of **non-nominated Lon-Term Physical Transmission Rights** and **Financial Transmission Rights**.	2,361.23
v	Costs of regional security coordinators (**RSCs**) and regional coordination centres (**RCCs**).	82.80
vi	**Ongoing investments or capital expenditure** for renewal, replacement, reinforcement of existing assets, or new assets contributing to maintaining or increasing cross-zonal capacity (including the costs of development and construction phases of such assets).	1,494.70
vii	**Cost resulting from past network investments** related to assets which significantly contribute to maintaining or increasing cross-zonal capacity, such as capital expenditure cost during depreciation period of asset.	659.11
viii	Other costs resulting from network investments which significant contribute to maintaining or increasing cross-zonal capacity, such as **OPEX, taxes, electrical losses** (excluding those losses cover by the Inter-TSO Compensation mechanism).	655.74

[93] SE: Expenditure and carry-over figures include CI originating from all borders, as it was not possible to distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders. CI allocated to Baltic Cable AB is not included in these figures.

Cost category	Definition	Value
ix	Other costs related to the **optimisation of usage** of new and existing assets which significantly contribute to maintaining or increasing cross-zonal capacity, where it is duly justified.	85.30

Source: ACER data collection from NRAs.

Note 1: The table is structured according to the classification of cost categories contributing to the priority objectives set out in Article 3 of the Use of Congestion Income Methodology in accordance with Article 19(4) of Regulation (EU) 2019/943.

Note 2: The total amounts are overstated, as also include expenditures from countries whose expenditure figures comprise CI generated at all borders, where it was not possible to distinguish CI derived from EU-EU borders only. For more details see table 18 below.

Table 18: Member States expenditure on priority objectives, by cost category, 2025 (million EUR)

Cost category	System operation costs					Network investments			
	i	ii	iii	iv	v	vi	vii	viii	ix
Austria	80.76				3.54	102.89	12.36	7.67	
Belgium						177.51			
Bulgaria				26.92		88.46			
Croatia	0	0	0	19.39	2.63	3.94	0	0	0
Czechia	0.09	0.31	0	64.36	0	0	12.91	0	0
Denmark[94]	0	0	0	0	11.30	0	119.60	50.80	78.50
Estonia				106.97	0.53	66.07		0.44	
Finland[95]	0.30	3.30		88.10	11.40	170.40		38.20	
France	99.60	4.60		803.50	13.00		217.70	447.70	4.50
Germany	152.68	7.78	0	467.89	0	574.83	0	0	0
Greece		18.73		34.88		2.00			
Hungary	0	0	0	85.58	0	0	0	0	0
Italy[96]	1148.43	24.53	73.18	398.74					
Latvia					16.34		5.50		
Lithuania	2.50	0	0	0	0	53.14	0	0	0
Netherlands		0.50		67.30				4.50	
Poland		0		2.91		51.75	31.67	5.37	0

[94] DK: Expenditure and carry-over figures include CI originating from all borders, as it was not possible to distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders.
[95] FI: Expenditure and carry-over figures include CI originating from all borders, as it was not possible to distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders.
[96] IT: reported expenditure under 'priority objectives' exceeds the available congestion income. Identifying the shares of EU and non-EU congestion income used would require a conventional allocation key for each cost category.

Cost category	System operation costs					Network investments			
	i	ii	iii	iv	v	vi	vii	viii	ix
Portugal	-0.15	0	0	9.84	0	0	0	0	0
Romania						15.28		5.93	
Slovakia						30.92			
Slovenia	0.53	1.19	0	52.53	7.55	0	19.85	22.83	0
Spain	48.85	2.98	0	132.33	0	157.55	23.33		
Sweden[97]	74.10		78.70		16.50		216.20	72.30	2.30

Source: ACER data collection from NRAs.

I. TSO capital and operational expenditures

Table 19: Electricity TSO capital expenditures (million EUR)[98]

	2019	2025	2030[99]
Austria	197	360 (2024)	Not available
Belgium	698	1424	Not available
Bulgaria	Not available	180	Not available
Croatia	74	178	Not available
Cyprus	Not available	74.86	22.41[100]
Czechia	202.26	455.07	505.83
Denmark[101]	343	954	2261
Estonia	51.8	175.7	128
Finland	123	485.1	500
France	1215	3035	5654
Germany	2727	16510 (2024)	Not available
Greece	238.789	1018.655 (2024)	Not available
Hungary[102]	51.27	107.9 (2024)	Not available

[97] SE: Expenditure and carry-over figures include CI originating from all borders, as it was not possible to distinguish CI expenditure financed by CI collected at EU-EU and EU-non-EU borders. CI allocated to Baltic Cable AB is not included in these figures.
[98] Note: The values refer to annual capital expenditure of the TSO and not the allowed CAPEX revenue (i.e. depreciation, return on equity, other CAPEX-related remuneration).
[99] For several NRAs, it has been estimated as a yearly average based on the national network development plan.
[100] CY: estimated CAPEX based on the approved NDP 2025-2034.
[101] DK: exchange rate used: 7.4516 DKK/EUR (2019, 2025).
[102] HU: exchange rate used: 325.35 HUF/EUR (2019), 395.2 HUF/EUR (2025),

	2019	2025	2030[99]
Ireland[103]	166.6	351.9	854.1
Italy	Not available	Not available	Not available
Latvia	85.41	160.09 (2024)	34.08
Lithuania	46	166	364
Luxembourg	19	7.8 (2024)	25[104]
Malta	NAP	NAP	NAP
Netherlands	1435	1983	9600
Norway[105]	1465	452 (2024)	1720
Poland[106]	393.148	481.939	1546
Portugal	132	281.8	Not available
Romania[107]	91.667	106.489	123.909 (2029)
Slovakia	74.58	110.93	112.97
Slovenia	72.1	83.8	107
Spain	280	657 (2024)	2300[108]
Sweden	234	960	2000

Source: NRA data provision in 2026

Table 20: Gas TSO capital expenditures (million EUR)109

	2019	2025	2030[110]
Austria	88	78	28
Belgium	37.9	213.4	80
Bulgaria	73.771	128.633	40.158
Croatia	47.2	119.5	443

[103] IE: The 2019 value includes the transmission asset owner (TAO) capital expenditures only, while the 2025 and 2030 values include both the TAO and the TSO capital expenditures.
[104] LU: calculated as yearly average from total TSO investment (2024–2034, transmission grid only)
[105] NO: 2019 marked a year of high investment levels due to the ongoing construction of two HVDC submarine power interconnectors, i.e. Nordlink to Germany and North Sea Link to the UK. The numbers reported are capitalized investments. Exchange rate used: 9,85 NOK/EUR (2019), 11,63 NOK/EUR (2024), 11,63 NOK/EUR (2030).
[106] PL: exchange rate used: 4.2693 PLN/EUR (2019, 2025, 2030).
[107] RO: exchange rate used: 4.7452 RON/EUR (2019), 5.0415 RON/EUR (2025, 2030).
[108] ES: estimated as a yearly average based on draft national network development plan 2025-2030.
[109] Note: The values refer to annual capital expenditure of the TSO and not the allowed CAPEX revenue (i.e. depreciation, return on equity, other CAPEX-related remuneration).
[110] For several NRAs, it has been estimated as a yearly average based on the national network development plan.

	2019	2025	2030[110]
Cyprus	0	0	Not available
Czechia	357.083	23.315	60.733
Denmark[111]	62	48	19
Estonia	78	9.5	12.3
Finland	Not available	Not available	Not available
France	414[112]	410[113]	Not available
Germany	1333	1518	Not available
Greece	Not available	156.965	Not available
Hungary	Not available	N/A	Not available
Ireland	27.453	120.287	Not available
Italy	Not available	Not available	Not available
Latvia	0[114]	7.1[115]	14.8
Lithuania[116]	17.73	21.8	Not available
Luxembourg	5.7	2	Not available
Malta	NAP	NAP	NAP
Netherlands	92.9	177	124
Norway	Not available	Not available	Not available
Poland	Not available	Not available	Not available
Portugal	7.6	15.3	Not available
Romania[117]	82.9	215.63	387.36
Slovakia	68.51	2.49	7.06
Slovenia	4.6	27.1	Not available
Spain	9.64	11.75 (2024)[118]	Not available

[111] DK: exchange rate used: 7.4516 DKK/EUR (2019, 2025).
[112] FR: the value refers to transmission capital expenditures only by the TSOs NaTran and Teréga; Storage capital expenditures include: EUR 155.1 million (Storengy); EUR 44.7 million (Teréga); EUR 18.0 million (Géométhane).
[113] FR: the value refers to transmission capital expenditures only by the TSOs NaTran and Teréga; Storage capital expenditures include: EUR 223.3 million (Storengy), EUR 53.2 million (Teréga, 2024), EUR 26.8 million (Géométhane).
[114] LV: Storage capital expenditures are not included. Capital expenditure for underground gas storage owned and operated by JSC "Conexus Baltic Grid", who is both the transmission system operator and the storage operator, is EUR 6.4 million.
[115] LV: Storage capital expenditures are not included. Capital expenditure for underground gas storage owned and operated by JSC "Conexus Baltic Grid", who is both the transmission system operator and the storage operator, is EUR 6.4 million.
[116] LT: Storage and LNG operator expenditures are not included.
[117] RO: exchange rate used: 4.7452 RON/EUR for 2019, 5.0415 RON/EUR for 2025 and 2030.
[118] ES: The value corresponds to CAPEX declared by the companies and refers to gas year.

	2019	2025	2030[110]
Sweden	2	2	4

Source: NRA data provision in 2026

Table 21: Hydrogen TSO capital expenditures (million EUR)[119]

	2019	2025	2030[120]
Austria	0	0	196
Belgium	0	80	Not available
Bulgaria	0	0	0
Croatia	Not available	Not available	Not available
Cyprus	0	0	Not available
Czechia	0	0	0
Denmark[121]	Not available	Not available	186[122]
Estonia	Not available	Not available	2.9
Finland	Not available	Not available	Not available
France	0	0	Not available
Germany	0	Not available	Not available
Greece	N/A	Not available	Not available
Hungary	Not available	Not available	Not available
Ireland	Not available	Not available	Not available
Italy[123]	Not available	Not available	Not available
Latvia	0	0	Not available
Lithuania	0	0	Not available
Luxembourg	0	0	Not available[124]
Malta	NAP	NAP	NAP
Netherlands	Not available	Not available	Not available

[119] Note: The values refer to annual capital expenditure of the TSO and not the allowed CAPEX revenue (i.e. depreciation, return on equity, other CAPEX-related remuneration).
[120] For several NRAs, it has been estimated as a yearly average based on the national network development plan.
[121] DK: exchange rate used: 7.4516 DKK/EUR (2019, 2025).
[122] DK: the figure is a yearly average calculated based on one EUR 930 million investment over the period 2026-2030
[123] IT: As of June 2026, the Italian NRA (ARERA) is not competent on hydrogen TSO investments.
[124] LU: Creos Hydrogen, a 100% owned subsidiary of Creos Luxembourg S.A., is the officially designated operator of the national hydrogen transport network. Their core investment and infrastructure plan focuses on the HY4Link project, a major cross-border network designed to integrate Luxembourg into the European Hydrogen Backbone (EHB).

	2019	2025	2030[120]
Norway	Not available	Not available	Not available
Poland	Not available	Not available	Not available
Portugal	Not available	Not available	Not available
Romania	Not available	Not available	Not available
Slovakia	0	0	Not available
Slovenia	0	0	Not available
Spain	Not available	10.3[125]	Not available
Sweden	0	0	100

Source: NRA data provision in 2026

Table 22: Electricity TSO operational expenditures (million EUR)

	2019	2025
Austria	170	108
Belgium	842	1265
Bulgaria	not available	611.5
Croatia	158	294 (2024)
Cyprus	7.06	5.94
Czechia	470.86	782.74
Denmark	153	288
Estonia	not available	not available
Finland	not available	not available
France	2706	4185
Germany	not available	not available
Greece	77.862	119.517
Hungary[126]	102.39	134.25
Ireland	73.4[127]	190.4[128]

[125] ES: The value was obtained from draft TYNDP 2026.
[126] HU: The value does not account for cost of ancillary services and network losses. The exchange rate used is 325.35 HUF/EUR (2019) and the exchange rate used is 395.20 HUF/EUR (2025).
[127] IE: The value includes the operational expenditures of the TAO.
[128] IE: The value includes TSO operational expenditures of EUR 103.6 million and TAO operational expenditures of EUR 47 million.

	2019	2025
Italy	not available	not available
Latvia	40.7	69.16 (2024)
Lithuania	27	59
Luxembourg	19.5	64.7 (2024)
Malta	NAP	NAP
Netherlands	246	553
Norway	214	341 (2024)
Poland	not available	not available
Portugal	27.3	27.3
Romania[129]	102.447	162.059
Slovakia	225.402	349.44
Slovenia	58	80.4
Spain	269	275 (2024)
Sweden	1032	2200

Source: NRA data provision in 2026.

Table 23: Gas TSO operational expenditures (million EUR)

	2019	2025
Austria[130]	143	95 (2024)
Belgium	181	245
Bulgaria	73.026	191.7
Croatia	25.6	37.1
Cyprus	0	0
Czechia	38.972	51.458
Denmark	37	98
Estonia	N/A	N/A
Finland	not available	not available

[129] RO: exchange rate used is 4.7452 RON/EUR (2019) and 4.9746 RON/EUR (2025).
[130] AT: the values include compressor energy.

	2019	2025
France	1062 (2018)[131]	1298.3 (2024)[132]
Germany	not available	not available
Greece	N/A	47.224[133]
Hungary	N/A	N/A
Ireland	75,957	135,65
Italy	not available	not available
Latvia	31.16	32.63 (2024)
Lithuania	19.1	52.7
Luxembourg	12.8	17.3 (2024)
Malta	NAP	NAP
Netherlands	314	579
Norway	not available	not available
Poland	not available	not available
Portugal	20.3	22.2
Romania[134]	143.22	198.44
Slovakia	89.91	51.68
Slovenia	19.0	27.1
Spain[135]	207.7	195.19 (2024)
Sweden	11	13

Source: NRAs data provision in 2026

[131] FR: the value includes only transmission operational expenditures. Storage operational expenditures: EUR 242 million (2019).
[132] FR: the value includes only transmission operational expenditures. Storage operational expenditures: EUR 243 million (2024).
[133] GR: the value includes only transmission operational expenditures. LNG operational expenditures: EUR 12.572 million.
[134] RO: exchange rate used: 4.7452 RON/EUR for 2019, 5.0415 RON/EUR for 2025).
[135] ES: Data provided by CNMC on gas OPEX corresponds to OPEX recognised by the NRA and corresponds to gas year.