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COMMISSION DE RÉGULATION DE L'ÉNERGIE

PUBLIC CONSULTATION No. 2025-08

The Energy Regulatory Commission (CRE) is consulting market participants.

Public consultation of 18 September 2025 on the ten-year development plan for the RTE network drawn up in 2025

Translated from the French: only the original in French is authentic.

In February 2025, the electricity transmission system operator, RTE, published a new version of its ten-year development plan for the electricity transmission network[1] (hereinafter referred to as the "ten-year plan" or "SDDR").

The SDDR is a proposal for the development of the transmission network up to 2040. It presents the strategies analysed and selected in terms of investment for the renewal and development of the transmission network, as well as the associated financial trajectories. It is therefore a forward-looking exercise: the investments that will actually be made over the next fifteen years may differ from those set out in the plan, depending on RTE's actual needs.

This vision covers all investments to be made by RTE in the transmission network:

- network renewal to compensate for ageing ;
- adaptation of infrastructure to climate change ;
- digitisation to improve network monitoring and controllability ;
- connections for new industrial consumers, new electrical substations for distribution needs, new producers (renewable energy, nuclear) or storage facilities ;
- changes to the structure of the electricity transmission network to adapt it to changes in production and consumption flows ;
- development of new interconnections with neighbouring countries.

In drawing up the SDDR, RTE considered the economic, energy and climate objectives set by France. The public policies implemented to reindustrialise France and increase its industrial sovereignty involve creation of new industrial zones and increased electricity needs in existing areas. Furthermore, the greenhouse gas emission reduction policies to which France and the European Union are committed require proactive programmes to electrify uses, which should result in an increase in electricity consumption, particularly in the transport sector and for the decarbonisation of industry.

To support these developments, electricity production will grow with the development of onshore and offshore renewable energies (RE) and new nuclear reactors. Increased use of consumption and storage flexibility should also enable overall optimisation of the system through ensuring the closest possible match between electricity supply and demand.

RTE's ten-year plan is based on various assumptions concerning the need to renew and digitise the network, changes in connection requests and changes in the French and European production mix. With regard to changes in consumption and production, RTE has studied two scenarios based on its 2023 adequacy mix forecast : scenarios "A" (achievement of public objectives) and "B" (lower growth in consumption and production). These scenarios are consistent with those envisaged by the State in its public consultation on the multi-year energy programme (PPE), published in March 2025[2] . Some trajectories do not depend on these scenarios : this is particularly the case for investments related to

[1] RTE's Network Development Plan (SDDR)

[2] Public consultation on the draft third edition of the Multi-Year Energy Programme (PPE)

network renewal, digitisation and adaptation to climate change, which will not depend on the rate of change in electricity consumption.

The law stipulates that the ten-year plan must be submitted to the national regulatory authority, CRE, for review to ensure, on the one hand, that all investment needs are covered and, on the other hand, that the SDDR is consistent with the ENTSO-E network development plan[3] (hereinafter TYNDP[4]). CRE may require the public transmission system operator to modify the ten-year network development plan.

In accordance with the provisions of Article L. 321-6 of the French Energy Code, CRE consults public network users on the SDDR submitted to it by RTE. The purpose of this public consultation is to gather the opinions of all stakeholders on the SDDR and on CRE's preliminary analysis. This consultation will be followed by a deliberation by CRE to examine the ten-year plan drawn up by RTE.

The SDDR will also be subject to an opinion from the environmental authority as part of the environmental assessment of plans and programmes, and has been forwarded to the Minister for Energy. In addition, RTE's SDDR is currently the subject of a public debate launched by the National Commission for Public Debate on 4 September 2025, which is scheduled to end on 14 January 2026.

RTE's Ten-Year Network Development Plan 2025 (SDDR) provides an in-depth analysis of the €100 billion of investment planned for the electricity transmission network between now and 2040.

RTE's ten-year plan provides an overview of the challenges ahead for the public electricity transmission network (RPT) and sets out the solutions proposed by RTE to meet them, not only in terms of network development and connecting new users, but also in terms of network renewal and digitalisation.

In this exercise, RTE maintained a high level of consultation with stakeholders. In particular, in March 2024, RTE organised a public consultation on the assumptions of the plan and presented its draft ten-year plan on several occasions to the committee of electricity transmission network users (CURTE).

For this edition, RTE has conducted in-depth analyses of the technical choices and conditions for the success of the various strategies. Each section of the SDDR thus presents alternative strategies with figures and the reasons for the choices made. RTE has also carried out non-financial analyses, particularly regarding environmental impacts and supply capacities from its suppliers. CRE welcomes these improvements , which enhance the quality and depth of the analyses.

Overall, RTE estimates that investments in the transmission network will amount to approximately €100 billion[5] over a period of fifteen years (between 2025 and 2039). They will grow significantly, from around €3 billion in 2025 to €8 billion per year by 2040.

The main elements of this trajectory are as follows:

- €20 billion for the renewal of existing infrastructure (and its adaptation to climate change). This includes, in particular, the renewal of approximately 21,000 km of existing lines, representing almost a quarter of the current network ;
- €4 billion for the digital backbone of the network, including the renewal of control-command systems and the connection of electrical substations to fibre optic networks ;
- €37 billion for connecting offshore wind farms, representing a total installed capacity of 22 GW in 2040 ;
- €16 billion for connecting land-based users, whether new consumers (industrial, distribution network operators), producers (renewable energy, nuclear) or storage facilities. Most of this expenditure (around €10 billion) will be borne by those requesting connection and not by network usage tariffs ;

[3] *European network of transmission system operators in electricity*

[4] *Ten-year network development plan*

[5] Unless otherwise stated, the amounts presented in this document are expressed in economic terms for the year 2024.

- €14 billion to adapt the extra-high voltage network structure to the growth in electricity consumption, particularly in industrial areas, and to the development of new means of production ;
- €2.5 billion to develop new interconnections with neighbouring countries.

RTE also estimates that an additional €11 billion could be invested over the SDDR period for projects that would come on stream after 2040, mainly for the connection of offshore wind farms and adaptations to the network structure. The connection of new nuclear reactors over the decade 2040-2050 also falls into this category but has not been precisely quantified due to a lack of specific information on the location of the sites.

In its SDDR, RTE also proposes various changes to the regulatory framework for connecting consumers, producers and storage facilities, and is seeking the opinion of CRE and the Minister for Energy , on their implementation.

In this consultation, CRE presents its main preliminary conclusions (summarised below).

Given the ageing of the lines, it is imperative for the renewal of the network to be accelerated over the next decade, which will provide an opportunity to adapt the network to climate change.

The pace of network renewal will increase in the coming years due to the ageing of lines built after the Second World War.

At this stage, CRE supports the investment strategies proposed by RTE in its SDDR for network renewal, which aim to strike an optimal balance between extending the service life of infrastructure and the risks of damage associated with older assets. Studies may be carried out to confirm the renewal criteria set out by RTE in the SDDR.

This major renewal programme will also enable the network to be gradually adapted to the consequences of climate change, with a limited additional cost estimated at 5% of the expenditure costs of new infrastructures.

In order to achieve the objectives set by France, network infrastructure must be planned and, in some cases, anticipated, even if uncertainties remain regarding changes in consumption and production.

The development of public transport network infrastructure requires long development times, up to 10 years for the most significant projects. These works will involve all industrial sectors, for the supply of materials or the completion of studies and works. These companies need visibility to be able to adapt to the expected growth in activity and plan the necessary investments.

CRE therefore supports at this stage the general strategy proposed by RTE in its SDDR, which consists of immediately launching the construction of the projects that offer the greatest benefits to the community and planning the construction of additional projects in line with the dynamics of consumption trends. This strategy carries the risk of sunk costs being borne by network tariffs but will ensure that the network does not become a limiting factor in the implementation of projects that contribute to the decarbonisation of the economy and the energy transition.

Under the supervision of CRE, RTE will adapt the investment trajectories presented (~€100 billion) to the reality of consumption and production development.

Most of the investment spendings proposed by RTE are linked to the development of new uses: connecting new consumers and producers, adapting the network structure to changes in flows. Only a part of these investments will be launched immediately by RTE, with the rest of the investments being conditional on the actual materialisation of needs. The investment plan will therefore be adapted to changes in electricity consumption over the coming years. For example, RTE estimates that these investments could amount to €82 billion in scenario B, which assumes more moderate growth in electricity consumption.

New very high voltage (400 kV) lines will need to be built in the coming years, and CRE considers that overhead technology will be necessary to ensure the sustainability of the SDDR.

CRE supports RTE's proposal to only launch the reinforcements of the very high voltage network that offer the most benefits to the users. Nevertheless, even with this cautious strategy, new very high voltage lines will be needed by 2040.

For the 400 kV voltage level, underground technologies are much more expensive (around 10 times more expensive) and have significant drawbacks in terms of land use, equipment availability and environmental impact. The price difference passed on to consumers would be likely to slow down the electrification of uses, with an additional cost of €40 to €70 billion over the SDDR period for the underground installation of new high-voltage lines.

The use of underground technology can be considered for high-voltage networks (63–225 kV) when the advantages are significant or the additional costs are limited.

At this stage, CRE supports the new strategy proposed by RTE for the use of underground technology for high-voltage networks (HTB 1 and HTB 2) in the following situations:

- to speed up the connection of new users (subject to their agreement) ;
- in urban areas and in certain areas with significant environmental challenges ;
- for single 63 kV and 90 kV lines, due to the low cost difference.

Increased use of the new flexibilities of the electricity system will necessarily have to accompany RTE's investment plan

CRE supports the use of the various flexibilities of the electricity system in order to limit investment needs. In particular, accepting a limited volume of renewable energy production curtailment will reduce investment expenditure for building new facilities. The flexibility provided by storage will also make it possible to limit the use of curtailment or reduce investment in areas with predictable constraints (high solar production during the day, high consumption in the morning and at the end of the day).

The efficient and rapid connection of new users is a priority that requires pooling, anticipation and prioritisation.

At this stage, CRE considers that the proposals made by RTE for connecting new users are relevant, particularly regarding:

- the prioritisation of certain areas for the mutualised connection of new industrial consumers, anticipating reinforcement work ;
- smoothing out the connection trajectory of future offshore wind farms over time, in line with industrial capacities in France and Europe, and enabling the associated costs to be controlled ;
- better consideration of network costs in future revisions of regional renewable energy grid connection plans (S3REnR) and alignment of regional objectives with national planning ;
- the establishment of a framework to guide storage operators towards the most favourable areas and enable them to connect quickly thanks to connection offers tailored to their intended use ;
- accelerated connection of industrial consumers in areas that are favourable for the grid and have been identified in advance by the State.

In general, CRE considers appropriate to develop connection procedures in order to better take into account the progress of projects, enable better use of available connection capacity on the network and identify projects that could benefit multiple users where possible.

France has carried out a vast programme of interconnections in recent years (projects completed or underway with Ireland, Spain, Italy, Germany, Belgium and the United Kingdom). Going further will require strengthening internal networks and ensuring the profitability of projects.

RTE's SDDR provides for the completion of several projects currently under way: Bay of Biscay with Spain, Celtic with Ireland, and various projects with Germany and Belgium, most of which are located on the other side of the border. These projects will increase the exchange capacity at borders by around 6 GW, compared with around 20 GW today.

Beyond this programme, increasing cross-border exchange capacity now requires, in most cases, internal upgrades to the electricity transmission network. At this stage, CRE agrees with RTE's analysis on this subject and has asked it to carry out studies on the necessary internal upgrades, in conjunction with its counterparts. New interconnection lines may then be considered, subject to positive cost-benefit analyses.

CRE also considers that the SDDR is consistent with the TYNDP developed by ENTSO-E, despite methodological differences between the two exercises.

In the scenarios presented, the effect of RTE and Enedis investments on electricity network tariffs (TURPE) would be approximately inflation +1% per year until 2040 for domestic customers.

The increase in RTE's investments will have to be financed by public electricity network usage tariffs (TURPE). CRE has estimated the effect of this investment plan on network users' bills, also considering Enedis' investment plan and various assumptions regarding changes in consumption and network operating costs.

The results of these simulations indicate that TURPE bills for customers directly connected to the public transmission network (TURPE HTB) will increase by 2% to 3% per year, in addition to inflation. However, many industrial customers, who account for most of the energy consumed by customers directly connected to the public transmission network benefit from the reduction provided for in Article L. 341-4-2 of the Energy Code. For these customers, the increase in TURPE bills will be very limited. The changes will be more moderate for domestic customers connected to public distribution networks, with a TURPE increase of around +1%/year in addition to inflation.

The realisation of these forecasts will depend on many external factors, such as the energy costs for covering the electricity losses of network operators, bearing in mind that the level of investment will be adjusted in line with changes in electricity demand.

Paris, 18 September 2025.

Responding to the consultation

CRE invites interested parties to submit their contributions by 15 November 2025 at the latest, via the platform set up by CRE: https://consultations.cre.fr.

In the interests of transparency, contributions will be published by CRE.

If your contribution contains information that you wish to keep confidential, a version with this information redacted must also be submitted. In this case, only this version will be published. CRE reserves the right to publish information that may be essential to all stakeholders, provided that it is not protected by law.

In the absence of an redacted version, the full version will be published, subject to information covered by legally protected secrets.

Interested parties are invited to respond to the questions, providing reasons for their answers.

Summary

1. List of questions

Question 1 *Do you have any comments on the scenarios selected and assumptions used by RTE in its SDDR?*

Question 2 *Do you have any comments on CRE's analysis of the effect of RTE's investment plan on electricity consumers' bills?*

Question 3 *Do you agree with CRE's analysis of the trajectory proposed by RTE for network renewal?*

Question 4 *Are you in favour of studying a strategy for renewing control and command systems that is less ambitious than the one selected in the SDDR?*

Question 5 *Do you agree with CRE's analysis of the strategy for making the network resilient to climate change?*

Question 6 *Do you have any comments on the connection costs presented by RTE? Do you agree with CRE's analysis on the importance of optimising the location of offshore wind farms in order to reduce connection costs?*

Question 7 *Do you agree with CRE's analysis of the strategy to be followed for contracting offshore wind farm connection equipment?*

Question 8 *Do you agree with CRE's analysis of the assumptions used in the SDDR for the development of onshore renewable energy production?*

Question 9 *Do you agree with CRE's analysis regarding the possible optimisation of network investment expenditure during future revisions of the S3REnR?*

Question 10 *Are you in favour of continuing to optimise the size of the network for connecting renewable energy producers?*

Question 11 *Do you agree with CRE's analysis regarding the use of storage to limit curtailment and investment needs?*

Question 12 *Do you agree with CRE's analysis of industrial connections?*

Question 13 *Do you agree with CRE's analysis of the strategy for strengthening the very high voltage network presented in the SDDR?*

Question 14 *Do you agree with CRE's analysis of the investments needed for voltage management?*

Question 15 *Do you agree with CRE's analysis of the use of overhead technology to reinforce the extra-high voltage network?*

Question 16 *Do you agree with CRE's analysis of the need to tailor the integration measures for 400 kV projects on a case-by-case basis, depending on local specificities?*

Question 17 *Are you in favour of the undergrounding criteria envisaged for HV 1 and 2 networks?*

Question 18 *Do you agree with CRE's analysis of interconnections under development?*

Question 19 *Do you agree with CRE's analysis of opportunities for developing new interconnections?*

Question 20 *Do you agree with CRE's analysis of the consistency between the TYNDP and the SDDR?*

Question 21 *Do you agree with the list of priority projects and associated milestones proposed by CRE? Are there any projects you think should be added to this list?*

Question 22 *Do you have any other comments on the SDDR presented by RTE?*

2. Framework for developing the ten-year network development plan

2.1. Legal framework

Article L. 321-6 of the French Energy Code stipulates that the public electricity transmission system operator (TSO) must submit a SDDR to CRE every two years. In accordance with the above provisions, this plan contains effective measures to ensure the adequacy of the network and security of supply.

The article mentioned stipulates that this plan must "take *into account the multi-year forecast and multi-year investment programme for production established by the State, as well as regional plans for connecting renewable energy sources to the network*". It must also be consistent with the ENTSO-E's TYNDP.

CRE is responsible for monitoring and evaluating the implementation of the ten-year network development plan. CRE examines the ten-year plan established by RTE to verify that all investment needs are covered and that the ten-year plan is consistent with the TYNDP. CRE may require RTE to modify the ten-year plan.

In this context, CRE conducts its own consultation with network users in accordance with Article L. 321-6 of the Energy Code and publishes a summary of this consultation.

This public consultation will be followed by a CRE deliberation on the review of the ten-year plan drawn up by RTE in 2025.

2.2. CRE's framework for analysing the SDDR

In accordance with Article L. 321-6 of the Energy Code, RTE published a new ten-year network development plan in February 2025 and submitted it to CRE for review on 1st April 2025.

The purpose of the SDDR review is not to approve RTE's annual investment levels, but to validate the methodology and principles used by RTE to determine new networks developments and the technological choices implemented in its projects.

The latest SDDR was published by RTE at the end of 2019.

CRE considers that the main principles for network dimensioning defined in the SDDR should be updated every three to five years. In view of the objectives pursued by the SDDR and the time required to draw it up, CRE considers that a three to five years cycle for its preparation would be appropriate.

CRE also has the power to approve RTE's investments on an annual basis, enabling it to regularly check the consistency of the investments made by RTE.

> ➢ The ten-year network development plan is an important document that describes the various investment strategies and associated financial trajectories. The implementation of these investments may differ from what is set out in the ten-year plan depending on actual needs, particularly changes in consumption and production. CRE also checks the relevance of RTE's investment programmes on an annual basis.
>
> ➢ Given that the SDDR contains long-term strategic guidelines and requires extensive consultation with stakeholders, a three to five years development cycle may be more appropriate.

2.3. Review of the implementation of the previous SDDR

RTE has published a review of the implementation of the previous SDDR[6] , which presented projected expenditure of around €$_{2019}$33 billion for 2021-2035. This review shows that:

- network renewal has accelerated with the implementation of the major industrial plans identified in the latest SDDR:

[6] Progress report on the implementation of the 2019 SDDR (2019-2024 period)

- the "corrosion plan" has enabled a threefold increase in the number of black steel pylons replaced in areas of high corrosion between 2021 and 2024 ;
- the number of electrical cables replaced or removed has increased, in line with the ageing of the structures, to reach between 700 and 900 km per year over the period 2021-2024 ;
- the implementation of the "GIS plan" has enabled a reduction of approximately 45% in SF_6 emissions in 2024 compared to the period 2015-2018.

The implementation of these industrial programmes has led to a doubling of investment expenditure for network renewal between 2019 and 2024.

- The optimal sizing of the network, the main cost control lever identified for network adaptations and the connection of new users (see section 8.1.4), was implemented by RTE and made it possible to free up approximately 18 GW of renewable energy capacity without any work. At the same time, RTE has carried out work to specify the needs for strengthening the 400 kV network in the four areas of fragility identified in the latest SDDR (Normandy-Manche-Paris, Massif Central-Centre, Atlantic coast, and Rhône-Burgundy).
- RTE has developed zone controllers for better congestion management (NAZA controllers[7]), with a deployment rate lower than that envisaged in the previous SDDR (only 15 controllers deployed by the end of 2024). In addition, as requested by CRE, RTE has launched an experiment on the use of storage flexibility as a substitute for network investments, which was contracted in the Perquié zone in 2024 ;
- the first stage of the offshore wind farm connection programme was a success, with the first connections coming on stream within the planned budget and timeframe (see section 7.1). At the same time, RTE has implemented an advance, standardised and consolidated procurement strategy for future connections (see section 7.3) ;
- interconnection projects that are beneficial to the community, in particular the Celtic projects with Ireland and the Bay of Biscay with Spain, are well underway. Studies have continued into the advisability of launching other projects (see section 11).
- the programme for developing and renewing the network's digital backbone has been thoroughly revised following review by CRE during the previous SDDR: RTE's strategy now provides for the renewal of control and command systems based solely on obsolescence criteria, and the development of RTE's telecommunications infrastructure has focused on substations that are critical to the security of the electricity system.

Changes in French energy policy, such as new ambitions to decarbonise industry and develop offshore wind farms, have raised new network development needs since the publication of the previous SDDR. These needs are examined in the SDDR 2025.

3. Main assumptions used by RTE

3.1. Different scenarios for the evolution of the electricity system considered

In its SDDR 2025, RTE has modelled two main families of scenarios, each of which has been subject to multiple variations (several hundred in total):

- **scenario A** corresponds to both a successful acceleration of the electrification of the economy and strong growth in electricity generation capacity. This scenario is consistent with the PPE submitted for consultation in March 2025[8] ;
- **scenario B** corresponds to slower growth in electricity consumption and production capacity. It corresponds to a delay of around five years compared with scenario A.

[7] New Adaptive Zone Controller
[8] PPE 3 consultation in March 2025

The reference strategy chosen by RTE in its SDDR is based on the study of these two scenarios:

- the trajectories related to connections (renewable energy, offshore wind, industrial, nuclear) are broadly based on scenario A. However, these trajectories will be adapted according to the actual needs related to these connections (see section 4.1.2);
- the trajectories linked to the structure of the very high voltage network consider profitable investments in the two scenarios studied (A and B) as well as the different variants on electrification or the development of new capacities.

The network's renewal and climate change adaptation strategies are independent of changes in the electricity mix and are not based on these scenarios.

The following paragraphs provide an analysis of the assumptions used for France. The assumptions used for other European countries are examined in section 11.3 in comparison with the TYNDP assumptions.

3.1.1. Assumptions for electricity consumption in France

In both scenarios studied, RTE forecasts significant growth in electricity consumption in France between 2025 and 2040. This growth is mainly driven by the development of electric mobility, the electrification of industry and the development of new uses (*data centres*, hydrogen production by electrolysis).

Scenario A thus forecasts strong growth in consumption, which would rise from around 450 TWh in 2025 to 615 TWh in 2035 and then 670 TWh in 2040. Scenario B assumes more moderate but nevertheless sustained growth compared to current consumption, with demand estimated at 555 TWh in 2035 and 615 TWh in 2040.

CRE notes that both scenarios are based on significant growth in electricity consumption, which is a notable shift from the trends observed in recent years. Electricity consumption fell by around 6% between the mid-2010s (consumption of around 480 TWh/year) and today's level (around 450 TWh/year). For the past 18 months, consumption has stagnated while electricity prices have returned to moderate levels. These factors have also been highlighted by RTE in its "Bilan prévisionnel" and annual electricity balance sheets.

There are many uncertainties surrounding the evolution of electricity consumption in the coming years, particularly regarding electric mobility, the electrification of industry and hydrogen production through electrolysis. For example, while RTE has received numerous connection requests from industrial customers, which in total would represent an estimated increase in consumption of +180 TWh/year (with a load factor of 100%), to date only 15% of these requests have resulted in the launch of connection work[9]. The commissioning of industrial facilities also requires ramp-up periods that can last several years.

The high level of uncertainty fully justifies studying contrasting scenarios, considering a delay in electrification and limited implementation of industrial projects. However, CRE notes that all scenarios, including the least ambitious one selected by RTE (scenario B), represent a marked break with the recent trend.

CRE therefore considers at this stage that the analysis carried out by RTE in the SDDR, based on the study of two scenarios, is relevant. It provides an account of the dynamics and investment strategies over a long-time horizon.

Before deciding to launch the most significant investments (see section 9), CRE plans to ask RTE to compare the technical and economic analyses of the projects with sensitivity studies that consider scenarios of lower growth in electricity consumption and production. For these decision-making studies, analyses based on an even lower increase in consumption and production would reflect a wider range of possible futures.

[9] Signing of the connection agreement corresponding to the start of work.

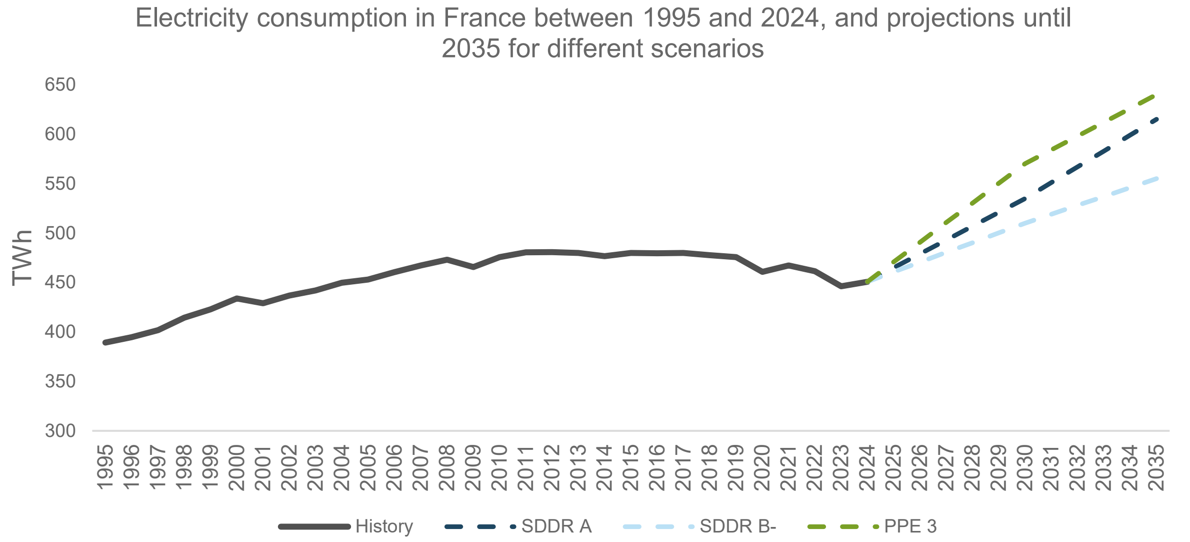

Figure1. Annual electricity consumption in France according to scenarios (sources: RTE, PPE submitted for consultation in March 2025).

- The use of several contrasting scenarios is good practice in forward-looking investment analysis. Although the scenarios studied by RTE in its SDDR are ambitious in terms of electricity consumption growth, CRE considers at this stage that they are sufficient for planning and investment strategy purposes.
- RTE has received numerous connection requests for new industrial projects or increases in power consumption at existing sites. All of these requests could represent up to +180 TWh/year of electricity consumption. Although the implementation of these requests has been limited to date (only 15%), they are expected to lead to growth in electricity consumption in the coming years.

3.1.2. Assumptions for electricity generation in France

The assumptions used by RTE in the SDDR scenarios for electricity production are adapted to the expected evolution of consumption:

- scenario A uses the highest assumptions, with the commissioning of two pairs of EPRs (Penly and Gravelines) by 2040 and a slightly higher rate of renewable energy development than in recent years;
- scenario B assumes a delay in the commissioning of EPRs after 2040 and a slower pace of renewable energy development, in line with the pace observed in recent years for wind power and down from the recent trend for solar power.

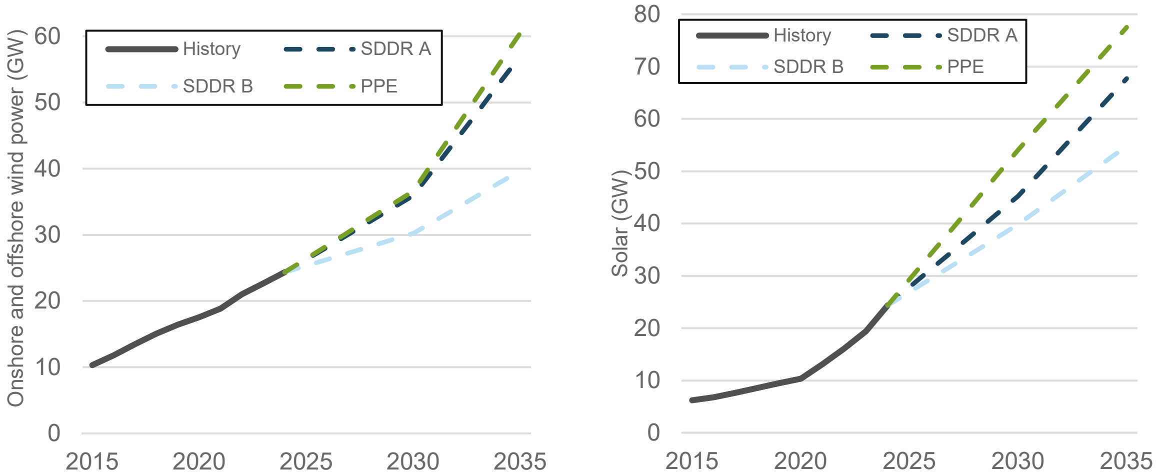

Figure2. Trajectories for the development of solar and wind power (onshore and offshore) (sources: SDDR 2025 RTE, PPE submitted for consultation in March 2025[10]).

At this stage, CRE considers that the assumptions made by RTE concerning the development of production capacity are consistent with recent development trends. The actual pace of development will depend on changes in electricity consumption over the coming years.

3.2. Project cost estimation framework

The project costing used by RTE in its SDDR 2025 is based on two different methodologies depending on the time horizons considered:

- for the period 2025-2030, the trajectories are based mainly on the costs of projects identified in the 2025 investment programme approved by CRE;
- for the period 2030-2040, RTE uses simplified costing based on reference costs by type of investment.

In particular, CRE asked RTE to justify the relevance of the cost references used in the SDDR. RTE therefore provided a comparative analysis between these cost references and the costs incurred for recently commissioned projects (where comparable recent projects exist). CRE considers this analysis to be satisfactory and believes that the cost references used in the SDDR are consistent with the history of recent projects.

Category of works	SDDR cost references
Creation of a 400 kV double-circuit overhead line (for a capacity of approximately 4 GW and including integration costs resulting from project consultation)	€2.5 to €3.9 million/km
Creation of a 2 GW capacity underground direct current line (range for distances of 50 to 100 km, including the cost of converter stations)	€20 to €35 million/km
Replacement of conductors for a single-circuit 400kV line	€0.9 to €1.5 million /km
Creation of a single-circuit 225kV overhead line	€0.6 to €1.5 million/km
Creation of a single-circuit underground line in HTB 2 (including integration costs resulting from project consultation and reactive energy compensation costs)	€1.1 to €2.2 million/km

[10] The data used for the PPE trajectory, submitted for consultation in March 2025, for the period 2030-2035 correspond to the average of the upper and lower ranges.

Creation of a 63-90 kV underground line (including project consultation integration costs and reactive energy compensation costs)	€0.8 to €1.4 million/km
Identical replacement of a 400 kV overhead line (partial or total)	€0.4 to €1.5 million/km
Identical replacement of a 225 kV overhead line	€0.5 to €1.3 million/km
Identical replacement of a 63-90 kV overhead line	€0.4 to €1.1 million/km
Creation of a 400 kV electrical substation	€50 to €100 million/substation
225 kV/63-90 kV transformer	€6.4 million/transformer
Substation cell (circuit breaker, disconnector, measuring transformer)	€0.6 to €0.9 million/cell
Connection of offshore wind farm to 320 kV or 525 kV direct current (offshore substation, submarine cable, onshore station)	€1.8 to €2.7 billion/GW

Table1. Examples of SDDR 2025 cost references.

> ***Question1*** *Do you have any comments on the scenarios selected and the assumptions used by RTE in its SDDR?*

4. Projected investment trajectories and tariff evolution scenarios

4.1. Variable investment growth depending on the scenarios considered

4.1.1. Reference investment trajectory

The reference investment trajectory presented by RTE in its SDDR shows total expenditure of €105 billion, in constant 2024 euros, over 15 years (2025-2039). Of this amount, €11 billion relates to projects that will be commissioned after 2040.

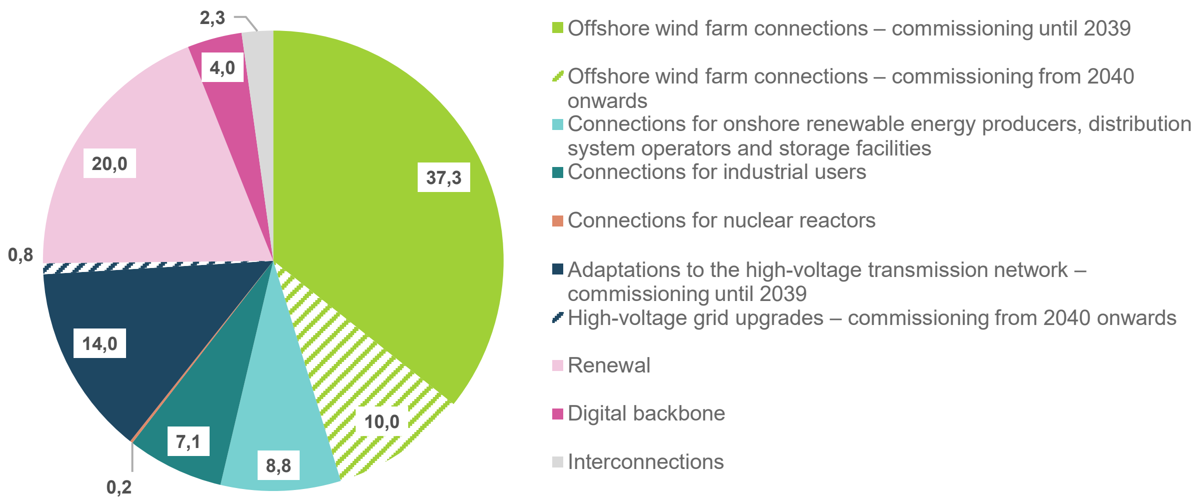

Figure3. Forecast investment expenditure for the period 2025-2039 (€bn $_{2024}$).

This reference trajectory forecasts a sharp increase in RTE's investments, which would rise from €2.1 billion/year over the period 2021-2025 to €7.9 billion/year over the period 2035-2039 (see Figure 4). This increase in investment expenditures is mainly due to:

- the connection of offshore wind farms (from €0.4 billion/year over 2021-2025 to €3.9 billion/year over 2035-2039, see section 7);
- network renewal (from €0.7 billion/year in 2021-2025 to €1.9 billion/year in 2035-2039, see section 5.1);
- adapting the extra-high voltage network to changes in consumption and production (from €0.3 billion/year over 2021-2025 to €1.0 billion/year over 2035-2039, see section 9);
- connecting new terrestrial users (from €0.2 billion/year over 2021-2025 to €0.9 billion/year over 2035-2039, see section 8);
- stable expenditure on the digital backbone of the network (€0.2 billion/year over 2021-2024 and over 2035-2039) after a slight increase over the period 2025-2030 (€0.4 billion/year on average) linked to the closure of Orange's copper local loop (see section 5.2).

The rest of this document includes a detailed analysis of the drivers of this increase by investment category.

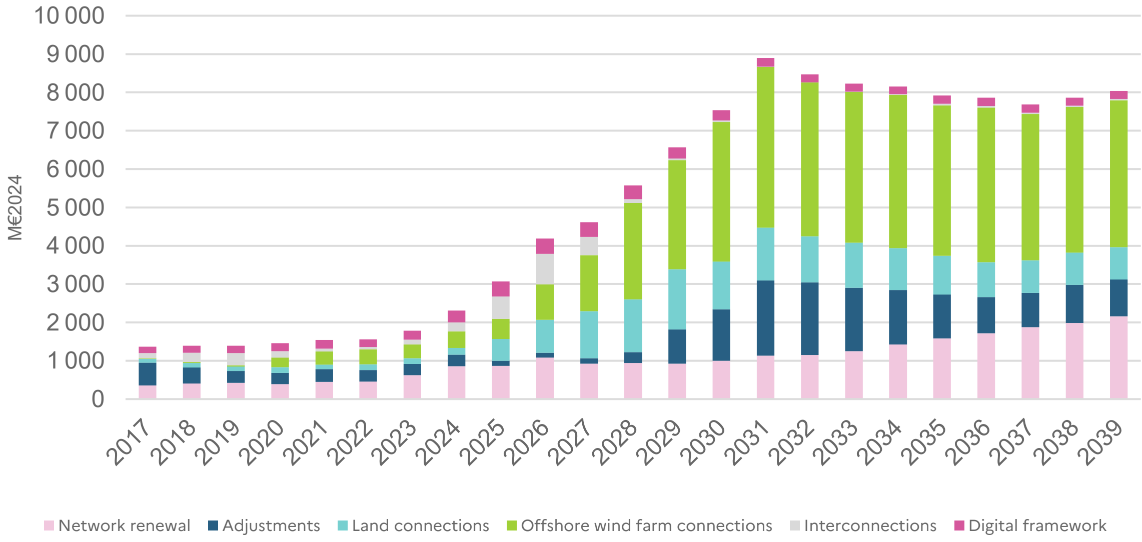

Figure4. RTE's "network" investment expenditure over the period 2017-2039 (M€2024).

Most of this investment expenditure will be financed by electricity transmission network usage tariffs. Their effect on changes in TURPE bills for network users is discussed in section 4.2.

Part of these investments is financed directly by applicants (connection charges) and will therefore have no effect on users' TURPE bills. RTE estimates that between €8 billion and €12 billion will be collected from connection applicants over the period 2025-2039, out of a total of €16 billion in RTE investments for grid connections (see section 8). However, all investments in offshore wind farm connections (see section 7) are covered by the TURPE, in accordance with the law.

> ➢ CRE points out that part of the expenditure planned in the SDDR will be financed directly by connection applicants. This financing would amount to approximately €10 billion over the period and will therefore not be covered by the TURPE.

4.1.2. Sensitivity of the investment trajectory to changes in the electricity system

The investment expenditures that will actually be incurred over the period 2025-2039 will depend on the actual changes in the electricity system over this period (see section 3.1). The reference trajectory presented by RTE in its SDDR, i.e., €105 billion, is based on:

- on assumptions of rapid changes to the electricity system, such as scenario A, for the connection trajectories of land-based and offshore users;
- assumptions of slower growth in consumption and production, as in scenario B, for the adaptation trajectory of the very high voltage network.

Part of these expenditures, including network renewal, digital infrastructure and adaptation to climate change, is independent of the choice of scenario for the evolution of the electricity system. These expenditures will be incurred regardless of the scenario chosen.

The other part of the projected investment expenditure for the period 2025-2039 will depend on the choice of scenario for the evolution of the electricity system. The expenditure trajectory presented by RTE is configurable and will be adapted according to actual developments in the electricity system. Forecast expenditure for the period 2025-2039 thus varies between €82 billion in scenario B and €110 billion in scenario A.

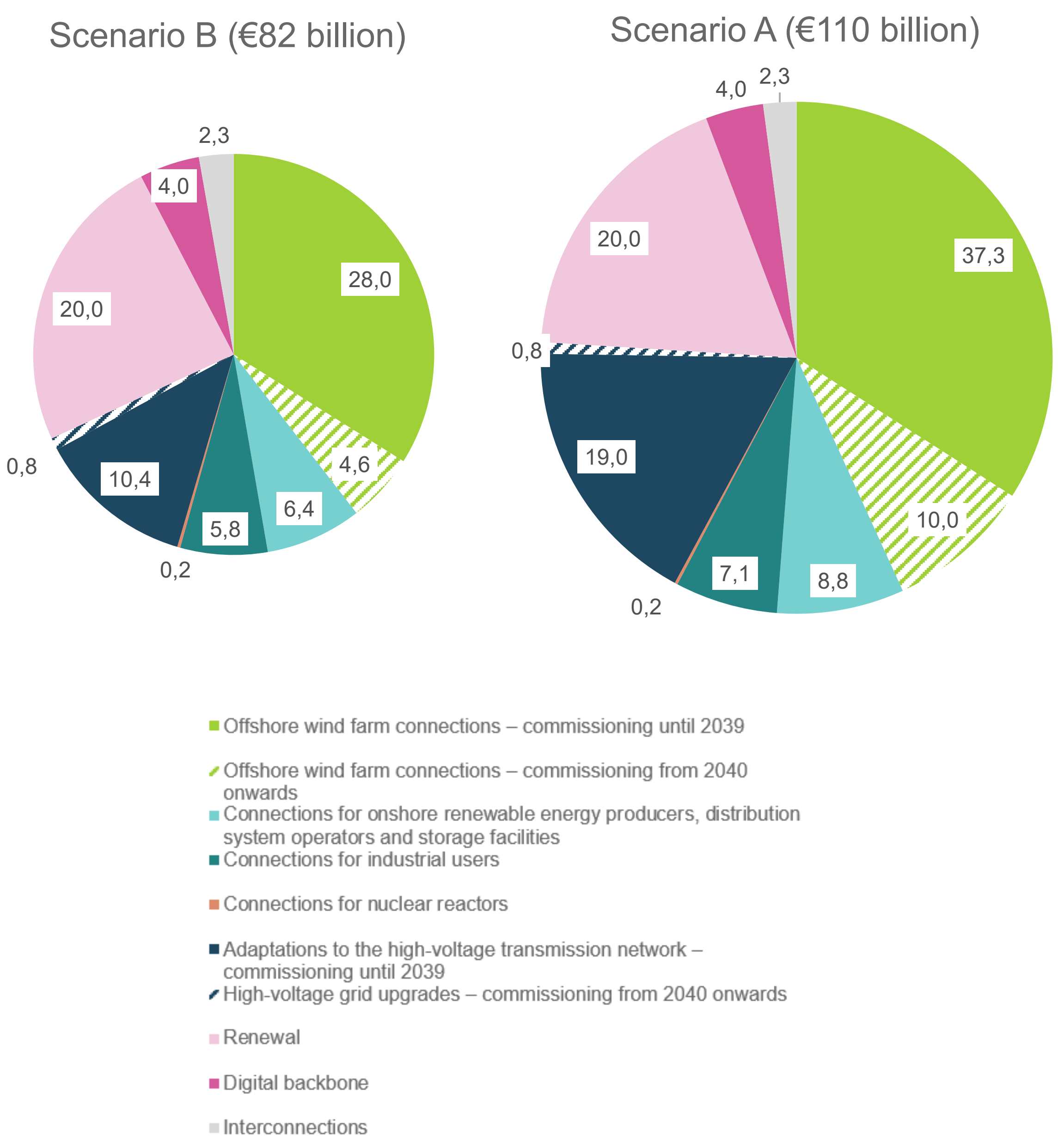

Figure5. Investment expenditure in scenarios A and B.

> - The investment expenditure trajectory for the period 2025-2039 amounts to €105 billion in the reference scenario adopted by RTE, taking into account projects scheduled to come on stream after 2040.
> - Part of the expenditures will be carried out regardless of the energy transition scenarios adopted, in particular the renewal of the network and its adaptation to climate change, which are key issues in the investments proposed by RTE in its SDDR (around a quarter of the total amount).
> - The rest of the expenditures will be adjusted according to actual developments in the electricity system. The total amount of expenditures planned over the SDDR period would thus be €82 billion in a scenario of lower growth in electricity consumption (scenario B). It would be €110 billion in a scenario of successful acceleration (scenario A).

4.2. An increase in investment leading to a controlled increase in network tariffs

4.2.1. Evolution of the TURPE HTB

RTE's investments are financed by the TURPE via capital costs: investments (excluding third-party financing) are included in the regulated asset base and are then amortised and remunerated over their entire economic life (generally around 40 years). The increase in RTE's investments will therefore lead to a more moderate increase in capital costs, as they are spread over the lifetime of the assets.

CRE estimated the effect of the investments planned under the SDDR on RTE's authorised revenue in a high variant (scenario A) and a low variant (scenario B), taking into account the investments according to the scenarios (€110 billion in scenario A and €82 billion in scenario B), the electricity consumption assumptions for these scenarios, assumptions regarding RTE's capital costs and operating expenses, and stable interconnection revenues at the TURPE 7 level.

These assumptions lead to authorised revenue for RTE for the year 2040 of between $€_{2025}$9.0 billion in the low variant (scenario B) and $€_{2025}$11.8 billion in the high variant (scenario A).

The level of this increase in RTE's authorised income will depend on developments in the electricity system, particularly the rise in consumption. The increase in electricity consumption will effectively reduce the rise in individual customer bills, as the additional costs will be spread over a greater quantity of electricity consumed. Furthermore, the effects will differ between customers directly connected to the transmission network (HTB), whose bills depend solely on RTE charges, and users connected to the distribution network (HTA-BT), whose bills also depend on distribution network operator charges[11] . In the following estimates for residential customers, CRE has also included Enedis' planned investment programme up to 2040.

4.2.2. Effect on the bills of RTE's direct customers

CRE estimates that the average TURPE bill for customers directly connected to the transmission network should increase from around 10.2 $€_{2025}$/MWh in 2025 to 13.7 $€_{2025}$ /MWh in scenario B (+ 1.9%/year excluding inflation) and to 16.2 $€_{2025}$ /MWh in scenario A (+3.1%/year excluding inflation).

The increase in the average TURPE bill for customers directly connected to the RTE network is significant. This observation must be qualified for two reasons.

On the one hand, the weight of the TURPE bill in industrial customers' electricity bills remains minor, in the order of 10 to 20% considering the levels of electricity bills observed before the crisis of 2021-2023[12]. The planned increase in the TURPE does not lead to a review of this minor nature of the bill.

Furthermore, around 40% of RTE's direct customers are eligible for the tariff reduction provided for electricity-intensive consumers[13]. These electricity-intensive customers account for most of the consumption by customers directly connected to the public transmission network. The average TURPE bill for these customers will be around 2€/MWh in 2025, and an increase of around 50% in the level of the TURPE HTB would bring this amount to around 3€/MWh in 2040. Maintaining this system would therefore greatly limit the impact of this increase on this category of customers.

[11] Under the cost cascade principle adopted in the TURPE HTB and HTA-BT, the TURPE bill for residential consumers covers the costs of the distribution network and part of the costs of the transmission network.

[12] Before the crisis observed on the electricity markets over the period 2021-2023, the electricity bills of companies consuming more than 0.5 GWh in mainland France ranged between €40 and €100/MWh. Source: annual publications by the Ministry of Ecological Transition on electricity prices in France and the European Union.

[13] Measures provided for in Article L. 341-4-2 of the Energy Code.

> - HTB consumers who are not eligible for the electricity-intensive discount would see a significant increase in their average TURPE HTB bill (+2 to +3%/year excluding inflation). However, this increase would remain manageable due to the minority weight of TURPE HTB in these customers' total bills (between 10 and 20% excluding the crisis experienced in recent years).
> - Around 40% of RTE's direct customers, representing the majority of industrial electricity consumption on the transmission network, are eligible for the electricity-intensive discount. This reduction will significantly limit the impact of the increase on these industrial customers. For these customers, this mechanism will therefore continue to play an important role in the coming years.

4.2.3. Effect on residential customers' bills

A majority share of the TURPE HTB is paid by distribution network operators and therefore *ultimately* borne, via the TURPE HTA-BT, by users connected at the distribution level. The increase in RTE's costs will therefore also have an impact on residential consumers' bills. However, the level of this increase will be lower than that for RTE's direct customers: it will be offset by the increase in consumption and the lower increase in Enedis's charges over the same period. Enedis' investment plan, amounting to €$_{2021}$96 billion (over the period 2022-2040, actually forecasts a smaller increase in investment than RTE's SDDR compared to the current level of investment.

On this basis, the transmission tariff (TURPE HTA-BT) for an average domestic consumer could increase by around 68.1€$_{2025}$ /MWh in 2025 to 79.1 €$_{2025}$ /MWh in scenario B (+1.0%/year excluding inflation) and 76.3 €$_{2025}$ /MWh in scenario A (+0.8%/year excluding inflation).

This increase in the TURPE HTA-BT would thus lead to an increase in the electricity bill for an average domestic customer, excluding inflation and changes in other components (supply and taxation), of between +0.3%/year in scenario A (+8.3 €$_{2025}$ /MWh between 2025 and 2040) and +0.4%/year in scenario B (or +11.1 €$_{2025}$ /MWh) between 2025 and 2040.

> - The investment trajectories presented by RTE in the SDDR and by Enedis in its investment plan will lead to a moderate increase in the transmission tariff for an average domestic customer, in the order of +1%/year excluding inflation. This represents an increase in the total bill for these users of between +0.3%/year and +0.4%/year excluding inflation and changes in other components (supply and taxation).

> ***Question2** Do you have any comments on CRE's analysis of the impact of RTE's investment plan on electricity consumers' bills?*

5. The pace of network renewal will need to increase due to its ageing

The electricity transmission network is, on average, around 50 years old. From 2030 onwards, a growing number of overhead lines, built after the Second World War, will reach the end of their standard life. This trend will continue in the coming decades with the renewal of lines built to support the development of nuclear power plants in the 1970s and 1980s. In the SDDR 2025, investments related to network renewal will increase from around €850 million in 2025 to €970 million per year over the period 2025-2029, then to €1.5 billion per year on average over the period 2030-2039 in RTE's reference scenario.

5.1. The trajectory for the renewal of power lines and substations will increase between now and 2040.

5.1.1. Reference investment trajectory for power lines and substations

RTE's overall planned renewal expenditure for power lines and substations totals €20 billion over the period 2025-2039. This expenditure concerns:

- €12.8 billion for the renewal of overhead lines, including the replacement of 21,000 km of connections;
- €1.5 billion for the renewal of underground lines;
- €3.4 billion for the reconstruction or refurbishment of 278 substations and 44 gas insulatedsubstations (GIS);
- €2.1 billion for the renewal of equipment (mainly power transformers, circuit breakers, disconnectors and measuring transformers) in existing electrical substations.

5.1.2. Renewal policy applied by RTE

For most of its assets, RTE applies a renewal criterion based on a standard service life, determined on the basis of experience, equipment types and technology. For example, the standard service life of electrical cables is 85 years and that of pylons located in areas of normal corrosion (ZCN) is 100 years. RTE regularly monitors its assets and the checks carried out may lead to renewals before the end of the standard service life when significant damage is found.

The standard lifespans used by RTE for electrical cables and pylons are at the upper end of the range used by other European transmission system operators.

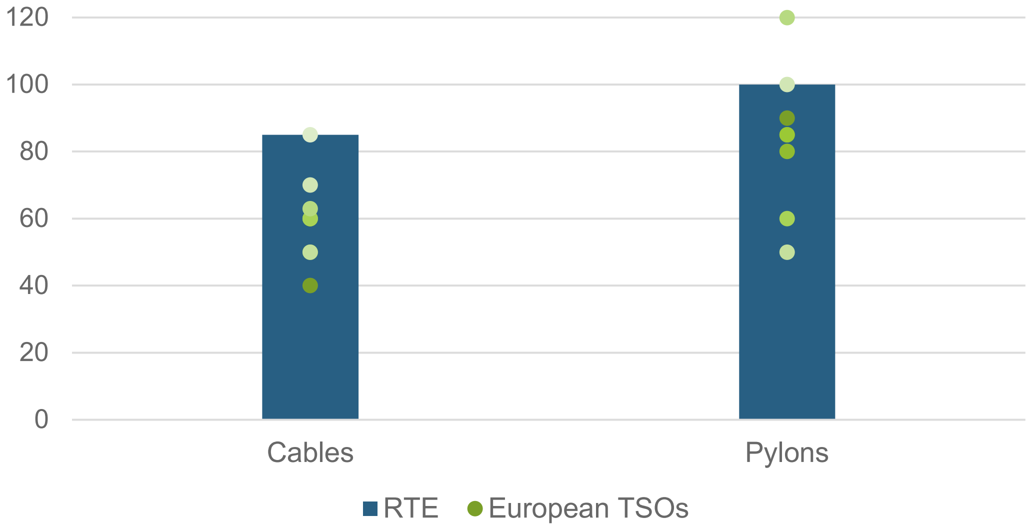

Figure 66 . Standard service life of transmission assets for different transmission system operators in Europe (years)[14]

The SDDR 2025 provides for several changes to the renewal policy. Firstly, RTE proposes to pool the renewal of electrical cables and pylons when one of the two components is eligible for renewal and the remaining lifespan of the other component is less than 15 years. RTE believes that the widespread renewal of overhead lines would generate savings on the fixed costs associated with these operations (consignments and access to structures, administrative authorisations, work management) and optimise

[14] The names of the TSOs concerned by the study are concealed for reasons of confidentiality.

routes (complete renewal allows the routes of power lines to be adjusted marginally to limit the use of expensive special foundations).

RTE has provided CRE with a technical and economic analysis showing that this strategy would reduce investment expenditure by around 10 to 20% compared with desynchronised operations. In view of these factors, CRE considers at this stage that this change is appropriate. CRE plans to ensure that these savings are effectively realised by specifically monitoring the cost of these operations.

Regarding electrical substations, RTE proposes to adapt the renewal of some of its assets (power transformers and measuring transformers) according to their actual state of deterioration, rather than systematically on the basis of normative age criteria. RTE estimates that the early renewal of 5% of the power transformer fleet, which is the most critical in terms of age (55 to 75 years) and the risk of outages in the event of failure, would generate savings for the electricity system of around €50 to €100 million over the period 2025-2039. These gains would result from a reduction in outages that could be caused by damage to these devices at the end of their service life.

At this stage, CRE is in favour of this approach, which aims to optimise the management of ageing assets by reducing critical risks and accepting a share of residual risks. Similar approaches are being implemented by other European network operators. CRE considers it important to generalise this approach, particularly regarding the renewal of power lines, which account for most expenditure over the SDDR period. This involves adapting the criteria for renewing power lines according to their actual condition and their criticality in terms of the risk of outages in the event of damage.

Finally, in accordance with the information provided to CRE as part of the analysis of the 2025 investment programme[15] , RTE proposes to review the plan for the reconstruction of metal-clad substations (GIS plan), for which early renewal no longer appears justified. RTE will now proceed with renewal based on the obsolescence of this equipment and notably spare parts or the use of SF_6 (insulating gas).The conditions for this obsolescence have yet to be specified by RTE.

> - The approach proposed by RTE to synchronise the renewal of cables and pylons is relevant and will generate savings through the pooling of operations.
> - The implementation of renewal criteria based on the actual condition of assets and their criticality, rather than normative lifespans, is good practice. In addition to electrical substations, these changes should apply primarily to the renewal of power lines, which represent the greatest financial challenges over the SDDR period.

5.1.3. Proposed strategy to address network ageing

The SDDR 2025 presents the age pyramids for electrical cables and pylons. Between 2025 and 2030, the volume of overhead lines eligible for renewal is stable, at around 800 km peryear. From 2030 onwards, and mainly after 2035, RTE identifies strong growth in the volume of overhead lines eligible for renewal, up to 2,000 km per year in 2040 (due to the ageing of overhead lines built to support the development of the nuclear power plant fleet).

[15] CRE deliberation of 13 March 2025 approving RTE's 2025 investment programme

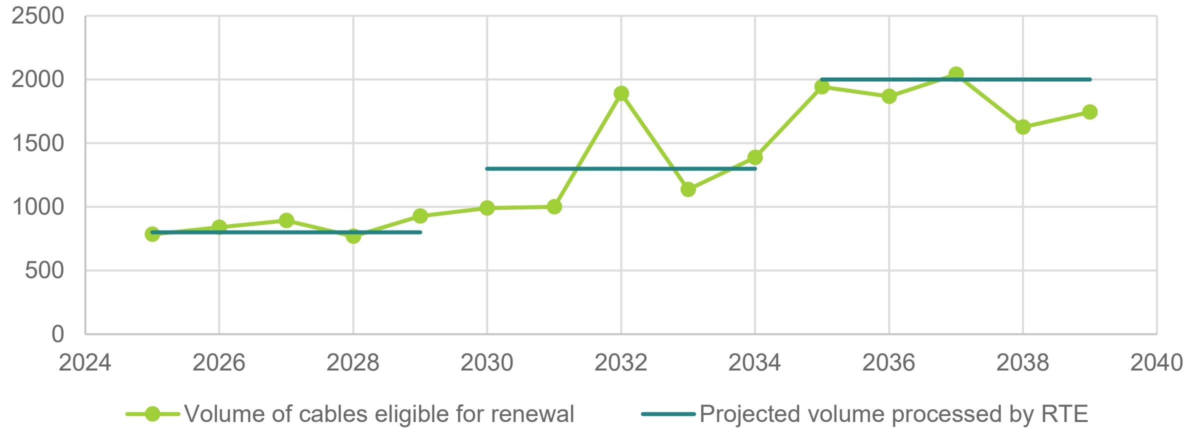

Figure 77 . Change in the number of cables eligible for renewal and the projected volume handled by RTE (km)

The dynamics are different for electrical substation equipment, which has a shorter standard service life (generally around 45 years). Nevertheless, RTE anticipates growth in the complete reconstruction of old electrical substations and GIS.

To address this issue, the SDDR presents five different renewal scenarios over the next 15 years, ranging from €12 billion to €29 billion over the SDDR period.

The strategy proposed by RTE (€20 billion over the period) does not involve renewing all equipment that has reached the end of its standard service life. In fact, RTE already operates some of its assets beyond this standard service life, with no visible impact on the quality of supply. This result can be explained by the actions implemented to monitor and improve the condition of equipment, as well as by uncertainties regarding the risk of damage to ageing assets. The strategy proposed by RTE therefore aims to maintain a constant volume of assets that have reached the current renewal criteria and to renew the most critical assets as a priority (age, importance to the network, resilience to climate change).

RTE's proposed strategy is gradual: the pace of renewal would be stabilised at the current level until 2030 and then accelerated over the period 2030-2040. For example, RTE plans to replace approximately 800 km of electrical cables per year between now and 2030, 1,300 km per year between 2030 and 2035, and 2,000 km per year between 2035 and 2040 (see Figure 10).

The renewal strategy must seek the technical and economic optimum between extending the service life of structures (thereby reducing investment expenditure) and limiting the risk of damage to ageing assets (which can lead to outages and therefore significant costs). From this point of view, CRE considers that the strategy proposed by RTE is appropriate and enables the currently defined renewal criteria to be met. Nevertheless, as mentioned in section 5.1.2, CRE considers that these renewal criteria should be improved, particularly with regard to overhead lines, in order to take into account the actual condition of the assets and the associated risks of damage.

CRE therefore considers at this stage that the first phase of consolidating the current pace of network renewal by 2030 is justified in view of the volume of assets reaching the end of their normative lifespan. CRE also considers that an increase in the volume of renewal will be necessary in the coming years, in line with the ageing of lines built after the Second World War. However, it considers it premature at this stage to comment on the proposed renewal rate for the period 2030-2040. Instead, CRE plans to ask RTE to first challenge the criteria used for the renewal of its assets, particularly overhead lines, with a view to confirming the pace of acceleration of renewal in the next SDDR.

Finally, CRE also plans to monitor various renewal indicators during the annual investment programmes. This list can be found in Appendix 1.

- The number of power lines reaching the end of their standard service life will increase from 2030 onwards, due to the ageing of lines built to support the development of France's nuclear power fleet.
- The strategy proposed by RTE aims to find the best compromise between extending the lifespan and the risks associated with older assets. At this stage, CRE considers that the strategy proposed between now and 2030 to renew assets that have reached the end of their standard lifespan is appropriate.
- Although the need to accelerate investment is established and shared by CRE, it is asking RTE to re-examine the criteria used for the renewal of its assets, particularly concerning overhead lines. These elements will make it possible to confirm the extent of the acceleration in renewals planned from 2030 onwards in the next SDDR.
- RTE should continue its efforts to manage and monitor renewal operations. A list of indicators will be defined by CRE to monitor annual investment programs.

5.1.4. Pooling of network renewal and adaptation operations

In constructing its forecast trajectory, RTE has considered the possibility of pooling network renewal operations with network adaptation and reinforcement operations (see section 9). RTE therefore anticipates that around 10% of old connections will be removed and rebuilt as part of projects to adapt and reinforce the existing network.

CRE considers it appropriate to seek the greatest possible pooling of network renewal and adaptation operations. However, the assumption used by RTE is equivalent to approximately 150 km of removed lines per year, which is well below the 300 km per year observed over the 2020-2023 period. CRE therefore plans to ask RTE to re-examine the assumption regarding the volume of lines removed[16] in light of the figures recorded in recent years and the growth in network adaptation work planned for the SDDR period. As the unit cost of removal is much lower than the cost of renewal, such an update could lead to a reduction of €1 to €2 billion in the investment expenditure planned in the SDDR, without changing the number of lines renewed over the SDDR period.

- The search for the greatest possible pooling of renewal and network adaptation operations is relevant.
- The assumption made by RTE regarding the volume of overhead lines removed should be re-examined in light of recent history and the growth in network adaptation work planned in the SDDR.

5.1.5. Zero-pesticide plan for the maintenance of electrical substations

Vegetation management at RTE's electrical substations has historically been carried out using plant protection products. Due to changes in regulations, RTE has proposed a "zero-phyto" plan aimed at reducing the use of plant protection products for the maintenance of electrical substations. CRE approved this plan in its deliberation approving the 2022 investment programme[17] , which provides for the cessation of the use of plant protection products for sites subject to a legal obligation or high vulnerability due to their proximity to a water source. Around 300 of the 500 sites operated by RTE (excluding substations operated by Enedis) are thus affected by the "zero-pesticide" programme approved in 2022.

In the SDDR 2025, RTE proposes to extend this plan to all sites operated by RTE. This expanded policy would represent additional investments of approximately €100 million compared to the plan approved in 2022.

[16] Dry deposits and as part of a pooling arrangement with network adaptation projects.

[17] [CRE deliberation of 20 January 2022 approving RTE's 2022 investment programme.]

At this stage, CRE considers that the plan approved in 2022, which includes a wide range of vulnerable sites, is already ambitious in view of the regulatory obligations. RTE has not been able to justify the additional costs expected from extending this plan to all electrical substations. CRE is therefore opposed to the proposed extension and plans to ask RTE to continue with the current plan.

- The cessation of the use of plant protection products for the maintenance of all electrical substations is not justified from a technical and economic point of view. The reduction in the use of these products must target sites that are subject to legal obligations or that are particularly vulnerable.

***Question3 4** Do you agree with the CRE's analysis of the trajectory proposed by RTE for the renewal of the network?*

5.2. A controlled trajectory for the renewal and reinforcement of the network's digital backbone

5.2.1. Reference investment trajectory

In its SDDR 2025, RTE presented a projected expenditure trajectory for the digital backbone of the network of €4 billion over the period 2025-2039. This trajectory aims to renew the transmission network's control and command systems (€2.7 billion over 2025-2039), renew and extend RTE's telecommunications network (€0.8 billion over the period), as well as ensuring network protection and deploying network monitoring and real-time action tools (€0.5 billion over the period).

The elements presented by RTE in the SDDR for this section are in line with the latest annual investment programmes approved by CRE.

5.2.2. Control-command renewal schedule

The strategy adopted by RTE in the SDDR provides for the renewal of control and command systems based on obsolescence criteria. This approach is consistent with the strategy approved by CRE in its deliberation approving RTE's 2023 investment programme[18] , and leads RTE to adopt a slightly increasing renewal rate over the period, from 550 units renewed per year in 2025-2030 to 600 units per year in 2040.

At this stage, CRE is in favour of maintaining the policy of renewing control-command systems based on obsolescence criteria. In its SDDR, RTE presents an alternative, less ambitious strategy, providing for the renewal of 500 units per year over the period 2025-2039. This strategy would involve reviewing the obsolescence criteria used to extend the service life of certain assets. RTE believes that the feasibility of this strategy is not guaranteed, particularly as it would require the reuse of spare parts recovered from decommissioned equipment.

Subject to its feasibility, this strategy could generate investment savings of €300 million over the period. These investments would result in slower development of digital systems, which does not appear to be detrimental given that the digitisation of control-command systems has not, to date, brought about any significant functional gains. CRE plans to ask RTE for a detailed analysis of the feasibility of this strategy and, if appropriate, to implement it.

[18] Deliberation No. 2023-39 approving RTE's investment programme for 2023.

- At this stage, CRE considers that the strategy of renewing control and command systems based on obsolescence criteria is relevant and will enable their gradual digitisation over the coming decades. Nevertheless, RTE should further examine the feasibility of the strategy of extending the service life of certain equipment envisaged in the SDDR, which could lead to savings of around €300 million in the period.

***Question 45** Are you in favour of studying a control-command system renewal strategy that is less ambitious than the one adopted in the SDDR?*

6. Adapting the transport network to climate change

6.1. The effects of climate change on the public transmission network

For the first time, the SDDR 2025 includes an analysis of the risks associated with the effects of climate change on the network. This analysis is important because electricity transmission infrastructure has a long lifespan (85 years for overhead lines) and the question of its resilience to future climate events therefore arises.

RTE has identified several risks related to the effects of climate change on its network:

- outside temperatures and power transits cause overhead lines to heat up, which leads to their expansion and therefore brings them closer to the ground. The increase in outside temperatures linked to climate change could therefore lead to a reduction in the transit capacity of overhead lines in order to limit their overall heating;
- rising outside temperatures could cause premature ageing of underground cables if they exceed their standard service temperature;
- The increased risk of flooding (sea flooding, river flooding, soil drought) may limit the availability of certain electrical substations and damage the equipment concerned.

To carry out its analysis, RTE considered the reference warming trajectory for climate change adaptation (TRACC) defined by the government, as well as the IPCC's RCP 4.5 and 8.5 scenarios[19] .

6.2. Building resilience in line with the pace of network renewal

The strategy proposed by RTE involves addressing climate change risks when constructing new assets and renewing existing ones, rather than carrying out work specifically dedicated to climate change adaptation.

This strategy considers the fact that structures have different vulnerabilities to climate change depending on their age. Older structures are generally more vulnerable because of lower requirements at the time of their construction. The strategy proposed by RTE in its SDDR will therefore enable the resilience of structures to climate change and their renewal to be pooled. For example, RTE plans to renew a quarter of the network's overhead lines during the SDDR period. These lines are generally the oldest and least resilient to climate change. The other lines will be renewed in the following decades.

Overall, RTE estimates that adapting new or renewed infrastructure to the future climate will generate additional costs of around €1.7 billion over the SDDR period, representing 5.4% of investment expenditure for creation and renewal of overhead lines and electrical substations. These additional costs are not isolated and are integrated into all the trajectories described in this public consultation (network renewal and creation of new infrastructure for connections or adapting the network structure).

At this stage, CRE is in favour of the strategy proposed by RTE, as it plans gradual resilience to climate change, while prioritizing the most critical structures. Resilience in line with the pace of network renewal makes it possible to avoid significant additional costs for early renewal of structures.

6.3. Sizing structures to cope with climate change

For each asset category, RTE is considering specific sizing for new infrastructure (creation of new infrastructure or renewal) to ensure its resilience to current and future climate conditions.

Regarding overhead lines, RTE must comply with a regulatory ground clearance depending on the voltage level. This implies a maximum operating temperature for overhead lines for a given reference pylon and cable, known as the distribution temperature. The current distribution temperature for new structures is 65°C, and RTE is proposing an increase to 85°C for its future lines, including a 10°C margin to cope with climate change between now and 2100, so that it can operate its network at higher

[19] *Representative Concentration Pathways scenarios* from the Intergovernmental Panel on Climate Change

temperatures. This change increases the cost of overhead lines by around 4%, mainly due to an increase in the size of pylons and cables.

For underground lines, RTE has opted to use underground cables with a larger cross-section, allowing for greater heating. RTE proposes to combine this new dimensioning with a reduction in the number of references used for underground cables in its new supply contract. The associated additional cost is therefore around 6% for the creation of a new underground line, around a third of which comes from oversizing resulting from the reduction in the number of references in the framework contract.

Regarding electrical substations, the main challenge is protection against extreme flooding. RTE has selected several solutions depending on the degree of flood risk at each substation: installation of barriers or waterproof enclosures, raising of substation equipment when creating new substations or for the most critical high voltage equipment. In particular, raising equipment entails an overall additional cost of around 10% of the cost of creating a new electrical substation.

CRE notes that the sizing choices made by RTE are consistent with climate change scenarios, in particular the TRACC defined by the public authorities.

The choice of distribution temperature for overhead lines is consistent with those made by other European network operators, which use temperatures between 75 and 85°C[20] . Nevertheless, CRE considers that RTE's choice should be justified based on a statistical analysis of future heatwave periods and the transmission capacities required during such events. This analysis could also be regionalised to take account of local dynamics. CRE therefore intends at this stage to ask RTE to provide further justification for this dimensioning.

Regarding the sizing of underground lines, RTE has not been able to justify the technical and economic benefits of the proposed new sizing in terms of limiting the risk of premature ageing and the gains in terms of reducing the risk of damage. CRE believes that such an analysis would better justify the sizing chosen for underground lines, without calling into question the need to size the network for a distribution temperature adapted to the future climate.

- Adapting the power transmission network to climate change does not require anticipating the renewal of assets before the end of their life. At this stage, CRE supports RTE's strategy of making the network resilient to climate change at the pace of renewals and the creation of new infrastructure.
- The additional cost of adapting the transmission network to climate change will be kept under control overall, at around 5% of investment expenditure for the creation and renewal of overhead lines and electrical substations. These investments will ensure that infrastructure built from 2025 onwards will be adapted to the future climate.
- RTE still needs to provide further justification for the design of certain structures in relation to climate change, particularly with regard to the 10°C margin for overhead line distribution temperature and the risks associated with the ageing of underground lines.

Question 5 *Do you agree with the CRE's analysis of the strategy for making the grid resilient to climate change?*

[20] The comparative data was provided by RTE on the basis of data supplied by its counterparts.

7. A significant proportion of investments relate to the connection of offshore wind farms

7.1. Reference trajectory for connecting offshore wind farms

7.1.1. A smooth connection rate over time

RTE's planned capital expenditure for the period 2025-2039 for the connection of offshore wind farms amounts to €37 billion for assets commissioned during this period, plus €10 billion for connections that will be commissioned from 2040 onwards. The connection of offshore wind farms therefore represents around 45% of the €105 billion budget planned by RTE for the period 2025-2039.

The trajectory presented by RTE is smooth: it anticipates the commissioning of no more than two connections per year after 2030. This smoothing considers the saturation of the market for the supply of specific equipment for these connections, and, according to RTE, will reduce costs and enable part of the production to be located in France (up to 50% of the value chain would be located in France for the connections of the farms launched in the next support tenders).

This smoothed trajectory will enable an installed capacity of 15 GW to be reached in 2035 and 22 GW in 2040. The 18 GW milestone is expected to be reached in 2037. This pace of development is slower than that envisaged by the ministerial decision of 17 October 2024[21] and the draft PPE submitted for consultation in March 2025, which envisage a target of 26 GW in 2040, or by the "Offshore Wind Pact[22] " of March 2022, with a target of 18 GW in 2035. However, the draft PPE submitted for consultation in March 2025 provides for the possibility of a two-year delay in relation to these targets.

- CRE considers it appropriate at this stage to smooth the commissioning of connections, at a rate of no more than two new farms per year, in order to build a realistic trajectory from an industrial point of view, control costs and increase the share of supply in France and the European Union for the offshore wind farm connection programme.

7.1.2. Sharp rise in the cost of connecting offshore wind farms

The contracts signed by RTE for the connections of wind farms AO 3 to 8 (see Figure 8) revealed a very significant increase in the costs of supplying and installing the equipment needed to connect offshore wind farms compared to the connections of wind farms AO 1 and 2 (on an equivalent scope[23]). This increase is due to strong pressure on the supply chain for this type of equipment, as well as the increased length of these connections. It has also been observed in other European countries.

[21] Decision of 17 October 2024 following the public debate "La mer en débat" (The sea under debate) on updating the strategic aspects of coastal strategy documents and mapping priority maritime and land areas for offshore wind power.

[22] Offshore wind energy pact between the State and the industry.

[23] For AO 1 and 2, RTE is solely responsible for the cables and the onshore substation. This scope was extended to the offshore platform from AO 3 onwards.

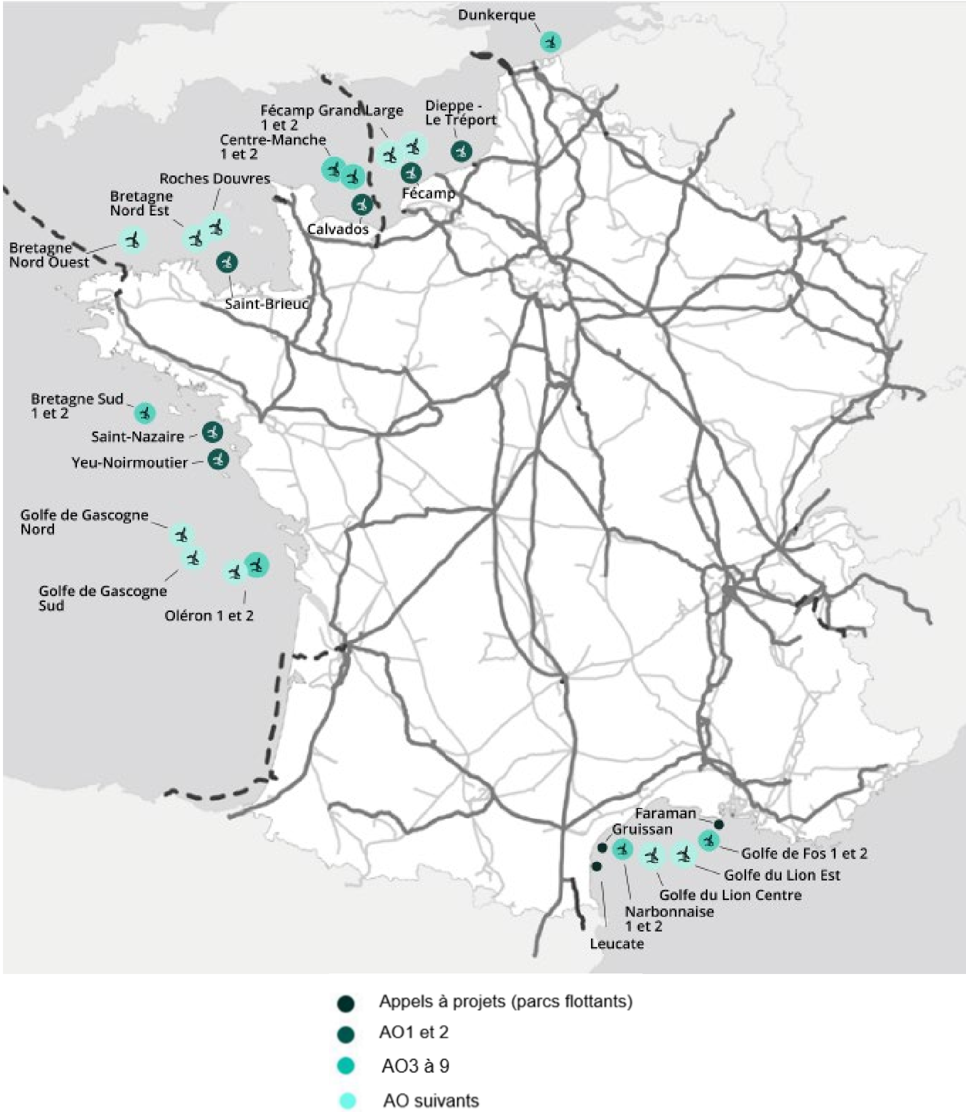

Figure 8. Map of offshore wind farm projects (source: RTE).

The results of recent calls for tenders by RTE and its European counterparts suggest that, for connections of around 120 km (100 km offshore and 20 km onshore), unit costs of around €2.0 billion/GW for 525 kV connections (farms of around 2 GW) and €2.2 billion/GW for 320 kV connections (farms of around 1.2 GW) are observed.

Under these conditions, the total cost of the connection would be between €30 and €40/MWh, representing between 35% and 40% of the total costs for the sector for fixed farms and around 30% for floating farms, which have higher production costs.

In accordance with Article L. 342-16 of the Energy Code, these costs are borne entirely by RTE and will therefore be financed by the TURPE HTB.

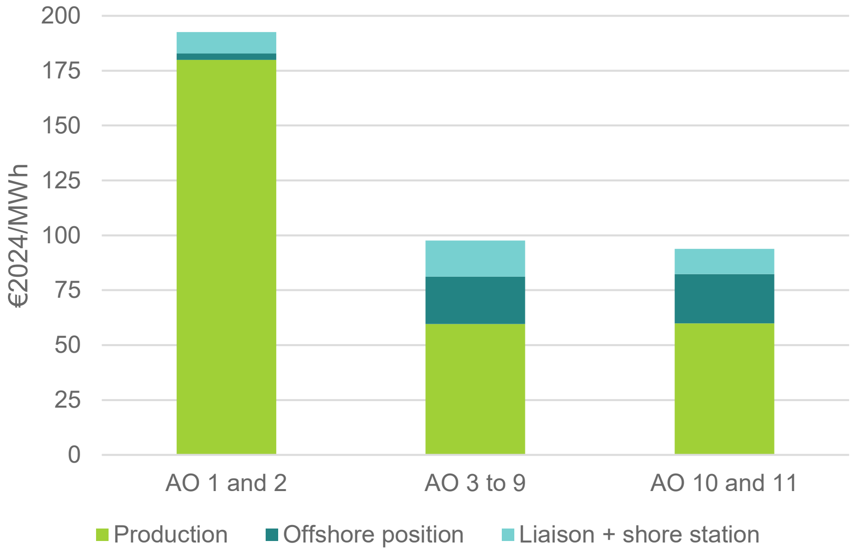

Figure 9. Total costs of the fixed offshore wind sector for farms in the various support tenders (source: RTE analysis).

These costs are highly dependent on the total length of the connection. Figure 10 below shows that reducing the total length of the connection would significantly reduce the costs of this programme. Reducing the total connection length from 100 to 50 km would reduce connection costs by around a quarter. This could be achieved either by bringing the farms closer to the coast or by locating the farms in such a way as to take advantage of the existing onshore grid to reduce the distance between the landfall and the connection point to the existing grid.

In addition to network costs, the distance of the farms from the coast also has an impact on construction and operating costs. In its SDDR, RTE estimates that the use of floating farm technology represents an additional cost of around 30€/MWh for the farm. Although the SDDR focuses on analysing connections made by RTE, CRE believes it is important to take all these factors into account when public authorities choose the location of future farms.

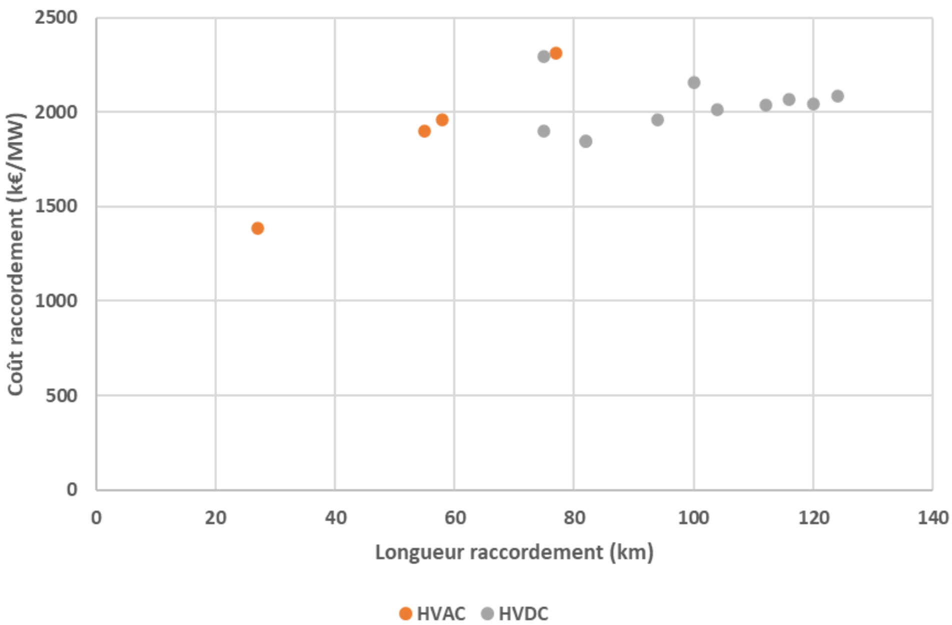

Figure 10. Connection costs based on connection length (source: RTE).

> ➢ Connection could account for around 40% of the total costs of the offshore wind sector for farms built between now and 2040. The choice of location for offshore wind farms, and in particular the total length of the connections, has a major influence on connection costs. The length of the connection does not depend solely on the distance from the coast: choosing sites with favourable landing conditions can also reduce these lengths and therefore the costs of connections.

***Question 66** Do you have any comments on the connection costs presented by RTE? Do you agree with CRE's analysis on the importance of optimising the location of offshore wind farms in order to reduce connection costs?*

7.2. A trajectory heavily dependent on the actual pace of offshore wind farm development

The actual expenditure incurred over the period 2025-2039 for the connection of offshore wind farms will depend on the actual pace of development of the sector in France. RTE forecasts that these expenditures could vary between €28 billion in a scenario of lower electrification (scenario B) and €46 billion to reach 26 GW connected in 2040:

- in scenario B (18 GW in 2040), RTE estimates expenditure over the period 2025-2039 at €28 billion for connections commissioned before 2040 and €5 billion for connections commissioned in 2040 or later;
- these expenditures amount to €37 billion for connections commissioned before 2040 in the SDDR reference scenario, which forecasts the connection of 22 GW in 2040, and €10 billion for projects commissioned in 2040 or later;
- achieving the target of 26 GW in 2040 would require higher expenditure: €46 billion for connections commissioned before 2040 and around €10 billion for those commissioned in 2040 or later.

> ➢ RTE's reference trajectory for connecting offshore wind farms amounts to €37 billion, to which €10 billion would be added for connections commissioned after 2040. This scenario would enable 22 GW of capacity to be connected by 2040. The trajectory is subject to significant uncertainty: expenditure would be limited to €28 billion in a delayed scenario reaching 18 GW in 2040, and could rise to €46 billion in a scenario reaching 26 GW in 2040 (to which would be added expenditure for connections commissioned after 2040).

7.3. Market conditions may justify bringing forward orders, but the strategy must take into account the risks of stranded costs

The connection of the first offshore wind farms by RTE has been a success: the connections for the AO 1 farms (Saint-Nazaire, Saint-Brieuc, Fécamp and Courseulles) were made available to producers within the contractually agreed deadlines and at a controlled cost below the target set in the previous SDDR (€630k/MW, excluding offshore platform costs, payable by the producer for AO 1 farms). The connections for the AO 2 farms (Noirmoutier and Tréport) are also under construction, with deadlines and costs under control.

Due to significant pressure on the supply chain for the equipment required for these connections, RTE brought forward the main orders for the connections for AO 3 to 9 wind farms in relation to the contracting of AO 1 and 2 wind farms. This move was accompanied by a strategy of grouping orders (multi-project purchases) and standardisation (one 225 kV alternating current stage and two 320 kV and 525 kV direct current stages). This strategy, similar to that adopted by other European TSOs, should enable connecting the AO 3 to 9 farms within the contractual deadlines, which represents a significant financial challenge: the compensation paid by RTE to the producer in the event of a delay, as defined in Article D. 342-4-12 of the Energy Code, can amount to more than ten million euros per month of delay.

However, the anticipation strategy and the associated contractual conditions entail a significant financial commitment on the part of RTE prior to the producers' final investment decisions.

Time before connection is made available	8 years	6 years	4 years	2 years
Typical 320 kV HVDC project (1.2 GW, €2.5 billion)	300	800	1,500	2,200
Typical HVAC project (750 MW, €1.4 billion)	10	150	400	1,000

Table 22 . Estimate of the upper limit of sunk costs (in € million) borne by RTE if the project is abandoned, based on the time remaining before the connection becomes available (source: RTE).

The abandonment of a park project by a successful bidder would not necessarily result in significant stranded costs for RTE. In such a situation, the public authorities have the option of appointing another successful bidder for the project. However, this would lead to additional operating costs for RTE, only part of which would be financed by the outgoing project developer through the collection of a bank guarantee[24] . Most of the stranded costs would therefore only materialise if the public authorities were to abandon the chosen location at a late stage, as RTE would then no longer have any interest in honouring the orders signed for the equipment.

In view of the significant amounts involved, CRE therefore considers at this stage that, for future contracts for the connection of AO 10, 11 and subsequent farms, RTE will have to adopt a contracting schedule that balances the risks between possible connection delays on the one hand, and the scale of stranded costs in the event of a possible abandonment of the calls for tenders on the other.

In addition, with a view to limiting any stranded costs borne by network users, the chronicle of potential stranded costs highlights the importance of correctly sizing the bank guarantees required from successful tenderers, as well as the need for the public authorities to quickly formalise any project abandonment situations.

- RTE has met the deadlines and costs planned for the connections of the AO 1 and 2 farms. The advance and standardised contracting strategy followed by RTE for the connections of the AO 3 to 9 farms should enable the connection deadlines to be met.
- However, this strategy involves early commitments for RTE and therefore a risk of significant stranded costs for RTE if projects or location choices are abandoned. For the connections of the parks in future calls for tenders, CRE considers at this stage that RTE will have to adopt a contracting schedule that limits the risk of stranded costs while complying with the contractual connection deadlines.
- CRE also emphasises the importance of properly assessing the bank guarantees required from successful bidders in future tenders and of quickly identifying any situations where projects may be abandoned.

Question 77 *Do you agree with CRE's analysis of the strategy to be followed for contracting offshore wind farm connection equipment?*

[24] When abandonment is not due to causes external to the producer and beyond its control.

8. A path for connecting new onshore producers and consumers that will require mobilising all levers of optimisation and flexibility

In the SDDR, RTE presents a projected expenditure trajectory leading to a total of €16.2 billion for connecting new terrestrial users over the period 2025-2039. This trajectory includes the connection works and upgrades to existing networks necessary to accommodate users, with the exception of adaptations to the extra-high voltage network structure (see section 9). This trajectory breaks down as follows:

- €7.3 billion for the connection of onshore renewable energy production as part of the Regional Renewable Energy Grid Connection Plans (S3REnR);
- €0.2 billion for the connection of new EPR 2 reactors. These expenditures correspond to creation or adaptation of electrical substations for the future reactors;
- €1.5 billion for the connection of distribution system operators. These investments will be linked to the needs of distribution system operators, in particular to support the development of electric mobility and industrial consumption connected to distribution networks;
- €0.1 billion for connecting storage facilities;
- €7.1 billion for connecting new industrial consumers to the public transmission network.

These investments are intended to meet the various connection requests made by applicants, who will finance most of these expenses. Of the €16.2 billion in projected expenditure, between €8 billion and €12 billion will be directly financed by connection applicants over the period 2025-2039 (see 4.1.1).

In general, the issue of timeframes is of paramount importance when it comes to connecting production, consumption, or storage facilities. CRE considers that all possible levers should be mobilised to optimise these timeframes.

8.1. Connection of onshore renewable energy production

RTE presents a projected expenditure trajectory for the connection of onshore renewable energy producers of €7.3 billion over the period 2025-2039. This trajectory is based on the use of various cost control levers, such as choosing favourable locations for wind farms from a network perspective and continuing to optimise sizing, which involves agreeing to modulate production at certain sites on an ad hoc basis in order to avoid the construction or reinforcement of new network infrastructure that is not economically viable.

8.1.1. Reference investment trajectory

The strategy for connecting onshore renewable energy sources is based on scenario A of the SDDR, i.e. 77 GW of onshore renewable energy production connected by 2030 and 136 GW by 2040. The trajectory proposed by RTE is constructed differently depending on the time horizons considered:

- For the period 2025-2030, the investment trajectory totals €2.7 billion in expenditure and is based on the projects identified in the S3REnR in force during this period;
- For the period 2031-2039, the investment trajectory totals €4.6 billion and is not directly based on existing S3REnR. It has been developed based on assumptions about the location of future wind farms to be connected and the resulting network costs.

RTE specifies in its SDDR that the trajectory presents uncertainties, both in terms of the actual volume of onshore renewable energy to be connected and the optimisation levers, in particular the location of renewable farms and the mobilisation of storage, which will enable investment expenditure of €2.1 billion and €0.5 billion to be avoided respectively.

8.1.2. A trajectory that will adapt according to the actual development of onshore renewable energy production

The SDDR trajectory will naturally adapt according to the capacities that are actually developed by 2040. RTE indicates, for example, that connecting 195 GW of onshore renewable capacity by this date instead of 136 GW, corresponding to the upper range of the PPE put out for consultation at the end of 2024[25] , would require additional investments of around €8. billion[26] . The SDDR is not intended to define the target capacity for onshore renewable energy production to be connected by this date, but will adapt to the objectives set by the public authorities.

The development of renewable energies is planned at regional level, within the S3REnR. The capacity already planned in the current schemes would reach 126 GW of onshore renewable energy production capacity if all the facilities planned in the schemes were commissioned. By the end of 2024, the capacity commissioned or reserved by applicants within these plans will reach 96 GW. Several plans are therefore saturated in contractual terms, i.e. almost all of the planned capacity has been reserved. Conversely, 30 GW of capacity is available in certain S3REnR schemes.

Several revisions of S3REnR schemes have been launched or will be launched in the coming months, in accordance with the law on accelerating renewable energy production (APER). At this stage, CRE considers that these revisions should incorporate the objectives that will be set in the future multi-year energy programme in order to ensure consistency between the development of renewable energies at local and national level.

Furthermore, CRE considers at this stage that it is appropriate to study the possibility of directing connection requests to areas where capacity is still available in the current S3REnR, particularly in substations where capacity is available without reinforcement or where work is scheduled within the next few years. Available capacity is reported by system operators on the Caparéseau website[27] . In its deliberations on TURPE 7 HTB, CRE identified the overhaul of Caparéseau as a priority action for the coming years. CRE considers that the analyses carried out in the SDDR reinforce the priority of this issue.

Upcoming revisions to the S3REnR could call into question the usefulness of some of the capacity available in the current plans. This would lead to the cancellation of projects planned in the current plans or the release of existing capacity on the transmission network, which could be used to connect other categories of users, in particular storage facilities.

Finally, CRE notes that there is a significant volume of projects currently eligible for connection in the S3REnR (waiting list), in the order of 46 GW. High-capacity projects connecting to the public transmission network are particularly uncertain due to their longer development times. Changes to RTE's connection procedures have therefore been approved by CRE in order to strengthen the conditions for remaining in the queue for projects connected to the public transmission network. At this stage, CRE considers that RTE must strictly apply these provisions in order to prevent projects that can be commissioned quickly from being blocked by projects that are not yet mature.

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[25] The SDDR was published in February 2025, and RTE's analysis is therefore based on the range published in the first consultation on the PPE at the end of 2024.

[26] Without implementing the optimisations planned in the SDDR, RTE estimates that the trajectory associated with renewable energy connections, the needs of distribution network operators and storage providers would be €19.8 billion in a scenario with 195 GW connected in 2040, compared with €11.4 billion for the 135 GW assumption used in the SDDR.

[27] Caparéseau

> - The investments planned in the SDDR will be adapted to national renewable energy development targets.
> - At this stage, CRE considers that the public authorities will have to ensure, when revising the S3REnR, that the capacities of these plans are consistent with the national objectives of the future multi-year energy programme.
> - Renewable production capacities should be directed primarily to areas where capacity is available under the S3REnR. Otherwise, these capacities should be released for other users, such as storage operators, during future revisions of the schemes. In saturated areas, work is planned by network operators to create new capacity.
> - At this stage, CRE considers that RTE will have to strictly apply the conditions for keeping projects in the queue as set out in the connection procedures, so as not to retain projects that have no prospects of progress and are blocking capacity.

> ***Question 88*** *Do you agree with CRE's analysis of the assumptions made in the SDDR for the development of onshore renewable energy production?*

8.1.3. The choice of location for the sites to be connected will have an impact on connection costs

The trajectory constructed by RTE for the period 2031-2039 is based on the connection of 53 GW[28] of renewable capacity defined among the sources declared by producers in the AERO database[29] . RTE estimates that a cost-optimised trajectory for the network would correspond to expenditure of €4.6 billion, whereas randomly selected locations would result in additional expenditure of €2.1 billion.

At this stage, CRE considers RTE's approach to be relevant and emphasises the importance of taking network costs into account in future revisions of the S3REnR. This optimisation could reduce reinforcement costs by around 30% when the selected sites are the most favourable for the network. In any case, minimising network costs will not be the only criterion for locating projects, as production capacity and land availability, for example, are key factors in project development.

Furthermore, at this stage, CRE considers that the financial trajectory for the period 2031-2039 should be improved. Indeed, some of the work planned for this period is already known and scheduled in the current S3REnR (even if some of these projects could be called into question during the next revisions of the S3REnR, as described in the previous paragraph). For known projects the costing should therefore be based on the currently planned costs of these projects. Where applicable, this work may also incorporate any revisions to the S3REnR that may be decided in the coming months.

> - For future revisions of the S3REnR, taking better account of network costs when selecting sources could reduce investment expenditure by up to 30%. However, this criterion will not be the only one used when selecting sources to connect.
> - At this stage, CRE considers that the financial trajectory proposed by RTE for the period 2031-2039 - should include the costs of the works planned in the S3REnR when they are known.

[28] These capacities will therefore enable 130 GW to be reached in 2039 and 136 GW in 2040.

[29] See in particular [Declaring and consulting renewable energy project forecasts - RTE Services Portal]

***Question 99** Do you agree with CRE's analysis regarding the possible optimisation of network investment expenditure during future revisions of the S3REnR?*

8.1.4. The use of occasional curtailments of renewable energy production allows for significant gains for the community.

The trajectory proposed by RTE in its SDDR incorporates the continuation of the optimal network dimensioning strategy from the previous SDDR, which consists of curtailing a small portion of renewable production in order to avoid the construction or reinforcement of new network infrastructure. In practice, RTE does not dimension the network to evacuate all onshore renewable production, which allows more production capacity to be connected to the unchanged network[30] .

According to RTE, the application of optimal dimensioning has already made it possible to create around 18 GW of capacity on the network between 2021 and 2024[31] , without making any additional investments. RTE estimates that optimal dimensioning has reduced investment expenditure by €1.8 billion over this period. These gains are significant compared to the corresponding curtailment costs (around €15 million for 2024).

In its SDDR 2025, RTE considers that continuing with optimal sizing would avoid investment expenditure of up to €22 billion over the period 2025-2039, in return for costs related to curtailments of around €70 million per year by 2040 (1 TWh of curtailments per year, or around 0.5% of onshore renewable energy production by that date).

CRE considers that implementing optimal network dimensioning brings benefits, in particular by reducing the overall costs of the electricity system. Furthermore, for a given network, optimal dimensioning increases the capacity available for connecting renewable energy sources and therefore reduces connection times.

CRE considers it important to limit the use of curtailment to what is strictly necessary. The operational implementation of curtailment can currently lead to preventive limitations that go beyond the actual needs of network operators, which constitutes a loss of economic value. RTE and Enedis have begun optimising curtailment, which will involve better coordination between network operators and the deployment of NAZA automatic control systems[32] .

- The implementation of optimal network dimensioning will generate significant gains for the community by reducing investment expenditure by up to €22 billion by 2040, offsetting the costs associated with curtailing a very small volume of renewable production (approximately €70 million/year in 2040). CRE emphasises the importance of controlling the associated curtailment volume, which is around 0.5% of renewable production, in particular through the development of NAZA automatic control systems.

***Question 1010** Are you in favour of continuing to optimise the size of the grid for connecting renewable energy producers?*

[30] These sizing methods are approved by CRE (French NRA), see in particular the [CRE of 21 January 2021 approving the methods for calculating the estimated cost of works to be carried out by RTE (French transmission system operator) as part of regional renewable energy grid connection plans.]

[31] This capacity would not exist on the network without the implementation of optimal dimensioning and would require investment to connect production.

[32] New adaptive zone controllers.

8.1.5. The use of external flexibility, particularly electricity storage, is essential to limit curtailment and reduce investment requirements

In its SDDR, RTE conducted a specific study on the benefits of using the flexibility provided by battery storage to reduce investment expenditure in the network. The SDDR notably forecasts that 6 GW of storage capacity will be connected by 2030, and that this capacity will remain constant between 2030 and 2040. This assumption was used by RTE in drawing up its 2023 forecast.

At this stage, CRE considers that this assumption of stability over the period 2030-2040 is not realistic given the growth in the flexibility requirements of the electricity system over this period. CRE therefore plans to ask RTE to review this assumption in the final version of its SDDR. This does not prevent us from drawing some initial conclusions based on the study carried out.

In its analysis, RTE distinguished between two theoretical methods of valuing storage resources in order to assess their impact on the grid:

- a valuation method based primarily on the provision of ancillary services: RTE concludes that locating these storage facilities in areas with unlimited available capacity makes it possible to shorten connection times and avoid costly upgrades (up to €2.5 billion in savings over the period compared to a situation where storage facilities are connected without limitation in constrained areas);
- a valuation method based primarily on arbitrage on the electricity markets, particularly between periods of high solar production during the day and periods of high consumption in the early morning or late afternoon. RTE estimates that locating these storage facilities in areas with high concentrations of solar production, particularly in the south-western quarter of France, would avoid around €500 million in network investments. This development could be promoted by the introduction of standardised connection offers (connection templates, allowing cheaper and faster connection in return for limitations on injection during periods of high solar production) and local calls for tenders, such as the Perquié zone awarded in 2024.

CRE considers that RTE's analysis is relevant for assessing the issues related to the connection of storage facilities. In practice, in the coming years, storage facilities will increasingly be managed by optimising all available recovery methods. It is therefore necessary to enable all storage facilities to obtain competitive connection offers that are adapted to the characteristics of the network.

In the short term, the development of standardised optimised connection offers (connection templates) provided for by TURPE 7 in areas with a high concentration of solar production will, on the one hand, accelerate the connection of storage facilities that accept countercyclical operation and, on the other hand, limit congestion in these areas. Similarly, the map published by RTE in early 2025[33] will guide storage operators who do not want limitations towards a location consistent with the needs of the system.

In addition, RTE must issue calls for tenders when contracting flexibility proves more advantageous than investments or curtailments. This is particularly the case when local grid congestion is due to a high concentration of solar production. As congestion is highly predictable and short-lived, adding storage capacity makes it possible to manage congestion and/or increase the capacity that can be connected to the equivalent network. At this stage, CRE considers that launching new calls for tenders should be a priority in order to realise the gains made possible by storage flexibility. The use of this solution should therefore be widespread.

RTE and Enedis have launched a trial to implement a common platform for contracting services to resolve congestion. This trial will enable competition and selection of the most effective means of resolving congestion, for example by mobilising battery storage or demand flexibility, instead of curtailment. CRE supports the widespread use of such a platform for all congestion resolution needs, as envisaged in the draft network code for demand flexibility[34] .

[33] Battery connection capacities.

[34] Network code on demand response, the draft of which has been submitted for consultation by the European Commission.

- CRE plans to ask RTE to review the assumption made in its SDDR regarding storage volumes in order to forecast growth beyond 2030.
- CRE agrees with RTE's proposal to enable storage operators to benefit from competitive and rapid connection offers in order to respond to the diversity of recovery methods. This will involve the publication of maps showing the available capacity for connections without limitations and standardised connection offers with limitations in areas with high solar production development.
- CRE highlights the potential of electricity storage to help resolve constraints on the grid, particularly those related to solar production. Local flexibility tenders could, in particular, make it possible to postpone or avoid certain investments, with savings of up to €500 million over the SDDR period. CRE plans to ask RTE to generalise the use of this solution.

Question 1111 *Do you agree with CRE's analysis regarding the use of storage to limit curtailment and investment needs?*

8.2. Connection of new industrial consumers to the transmission network

8.2.1. SDDR reference investment trajectory

RTE presents a projected expenditure trajectory for connecting industrial consumers of €7.1 billion over the period 2025-2039. This expenditure corresponds to the connection of new industrial sites requiring significant power (heavy industry, *data centres,* hydrogen production by electrolysis) or the electrification of existing processes (e.g. the use of electricity for heat production or electric furnaces).

In recent years, RTE has received a large number of connection requests from industrial consumers. There is considerable uncertainty as to whether these requests will be fulfilled (see section 3.1.1). In response to these requests, RTE has proposed a strategy in its SDDR to prioritise and pool industrial connections.

Half of the investment expenditure estimated by RTE therefore relates to connections in shared areas, for which applicants are billed a share of the investment made in proportion to their connection power. The other half of the expenditure relates to individual connections without mutualisation. In general, 70% of this expenditure will be financed by the applicants and 30% will be covered by the TURPE.

8.2.2. A prioritised trajectory to accompany the implementation of connection requests

In its SDDR, RTE proposes the following strategy:

- the launch of network reinforcement works in three priority mutualisation areas known as "P1 areas", as soon as administrative authorisations have been obtained. These areas represent expenditure of around €1.5 billion over the SDDR period: the industrial areas of Dunkirk, Fos and Le Havre;
- the completion of detailed studies in the second priority areas, known as "P2 areas"[35] , where the launch of work would be conditional on a commitment from the manufacturers concerned. These areas represent expenditure of around €700 million over the SDDR period;
- in the other areas, known as "P3 areas"[36] , RTE plans to implement plans to accelerate network development if industrial players commit to the project. These areas represent expenditure of around €1.4 billion over the SDDR period.

[35] These zones correspond in particular to the Loire-Estuaire, Île-de-France Sud, Saint-Avold, Sud Alsace, Vallée de la Chimie, Plan de Campagne and Valenciennes zones.

[36] These zones correspond in particular to the zones of Greater Lyon, the Pyrenees, Port-La-Nouvelle, Châteauroux, Haute-Vienne and the Paris region. Other zones may be added depending on the connection requests received in the coming years.

With regard to the P2 and P3 zones, RTE proposes to work with government departments and CRE to identify the work that would be appropriate to launch in the coming years.

CRE is in favour of implementing shared infrastructure for connecting industrial users in areas where several requests have been received. Sharing infrastructure makes it possible to better assess the scale of the reinforcement work required and to speed up connections by anticipating the work. However, this infrastructure presents a higher risk of stranded costs than the traditional connection framework: if projects are abandoned, the portion of investments not used for connecting industrial customers would then be financed entirely by the TURPE.

RTE has received numerous connection requests in industrial areas identified as P1. CRE therefore considers it appropriate to start work in these areas in advance.

With regard to the other areas, identified as P2 or P3 by RTE, CRE considers it appropriate to wait for sufficient commitment from industrialists before actually starting work.

In all cases, RTE must submit the investments and share associated with these shared connections to CRE for approval[37] . Where possible, CRE supports the implementation of phased investment strategies that allow work to be sequenced in line with the pace of connection requests, thereby limiting the risk of stranded costs. This is, for example, the strategy envisaged by RTE for the Loire-Estuaire area[38] .

Finally, on 7 May 2024, CRE approved the new procedure proposed by RTE to accelerate the connection of very high-power consumers (between 400 MW and 1 GW) to RTE's very high-voltage grid by 2028-2029[39] . At sites previously identified by the State, this procedure offers project developers the possibility of requesting accelerated and unlimited connection to the grid.

- At this stage, CRE supports RTE's proposed approach of starting work in P1 areas, where numerous connection requests have been received, without waiting for final commitments from manufacturers.
- For other areas, CRE considers it appropriate to wait for commitments from industrialists before starting work.

Question 1212 *Do you agree with CRE's analysis of industrial connections?*

9. A cautious strategy for adapting the extra-high voltage network in the face of uncertainties about changes in consumption and production

In the SDDR, RTE presents a projected expenditure trajectory of €14 billion over the period 2025-2039 for the reinforcement of the extra high voltage network (EHV, the 400 kV network and part of the 225 kV network) and the implementation of a transmission network voltage management plan. RTE also anticipates €800 million in additional expenditure over the SDDR period for projects coming on stream from 2040 onwards. These upgrades should enable the EHV network to adapt to changes in the French energy mix, in particular the increase in electricity consumption and the development of renewable and nuclear power generation. They should also help to limit the costs of de-optimising the production plan due to network constraints (congestion costs).

[37] In accordance with the Energy Code and the principles defined in the CRE's deliberation of 7 November 2024 on the conditions for approval, the content and preparation of requests for the mutualisation of connections of consumers and distribution network operators to the public transmission network.

[38] CRE deliberation of 5 December 2024 on the anticipation and mutualisation of connections by consumers and public distribution network operators to the public electricity transmission network in the Loire-Estuaire area.

[39] Deliberation of the Energy Regulatory Commission of 7 May 2025 approving the procedure for processing applications for connection to the public electricity transmission network of consumption facilities in the HTB3 voltage range at previously identified suitable sites.

9.1. SDDR reference trajectory for adapting the extra-high voltage network

9.1.1. An initial set of projects already identified

The trajectory proposed by RTE is initially based on a foundation of already identified network reinforcement projects, for which detailed studies and consultation phases have been launched. These projects represent expenditure of around €700 million for the construction or reinforcement of nearly 300 km of overhead lines:

- the construction, at a cost of around €350 million, of a new 400 kV overhead line between the municipalities of Amiens (Somme) and Petit-Caux (Seine-Maritime), which will enable the evacuation of electricity generated by the EPR 2 reactors in Penly and offshore wind farms in the English Channel;
- the creation, at a cost of around €100 million, of a new 400 kV line parallel to the existing line between Chaingy (Loiret) and Dambron (Eure-et-Loir), strengthening the link between Paris and central France;
- the renovation, at a cost of around €230 million, of the 400 kV line between the Marmagne (Cher) and Tabarderie (Loiret) substations, involving a change of conductors, which will also enable the line between Paris and central France thanks to more efficient equipment.to be modernised

In its deliberations on RTE's 2025 investment programme[40], CRE asked RTE to systematically submit a detailed cost-benefit analysis for projects representing expenditure in excess of €200 million, in order to decide on the approval of these projects on an individual basis. CRE will therefore examine the merits of the various projects envisaged by RTE after receiving the corresponding cost-benefit analyses.

CRE notes that some of these projects involve reinforcement work on existing lines, which will require them to be temporarily taken out of service. This work will therefore need to be planned in order to limit the impact associated with the unavailability of the infrastructure. As such, RTE plans to organise a consultation within the CURTE (Regional Electricity Coordination Committee) on the terms of coordination with its customers for the completion of scheduled works. CRE is in favour of launching this consultation, which aims to take into account the increase in the volume of work to be carried out on the network.

9.1.2. A second phase of reinforcements identified on the basis of conservative assumptions

The additional projects to strengthen the EHV network envisaged by RTE in the SDDR have been identified on the basis of analyses based on scenario B of the SDDR. These analyses are therefore based on assumptions of slower growth in the electricity system than those predicted by the public authorities. They make it possible to identify projects that are profitable even in the event of less electrification of the French energy system.

This trajectory includes €4.3 billion for the "Gironde – Loire-Atlantique" (GiLA) electricity line project, for which CRE approved preliminary study expenditure in 2023[41] . This submarine direct current project will enable the connection of one or more future offshore wind farms on the Atlantic coast to be shared with the reinforcement of the area. The initial results of the studies confirm that the economic interest of the project will be conditional, at *a minimum,* on the sharing of this reinforcement with the connection of offshore wind farms.

This trajectory also provides for €7 billion over the period 2025-2039 to reinforce seven network areas where RTE has identified risks of significant increases in congestion costs between 2030 and 2040. These projects, planned using overhead alternating current technology, will enable the reinforcement or creation of nearly 2,000 km of connections. Once the technical details of these projects have been finalised, RTE will carry out additional cost- -benefit analyses to confirm the value of the projects. CRE

[40] CRE deliberation of 13 March 2025 approving RTE's 2025 investment programme.

[41] CRE deliberation of 21 September 2023 on the implementation of the 2022 investment programme and approving RTE's revised 2023 investment programme.

will approve the launch of the most important projects on an individual basis. At this stage, CRE considers that RTE's case-by-case analyses should include an alternative scenario of more significant delays in consumption (see 3.1.1) to ensure the robustness of investment choices across a wide range of possible futures.

At the national level, RTE estimates that the identified upgrades will limit congestion costs by 2035 in all identified scenarios: these costs would then be between €200 and €400 million per year, according to RTE. However, they would increase significantly by 2040 if public targets were met (approximately £2 billion per year according to RTE in scenario A with the planned reinforcements). Additional reinforcements will then be launched following future studies, when uncertainties over this period are less pronounced.

At this stage, CRE considers that identifying the upgrades that will limit congestion costs in all scenarios is relevant. Nevertheless, this analysis should be supplemented by a study of the main drivers influencing this strategy. Some developments could have a major influence on investment choices in the coming years (continued location of solar production in the south-western quarter of France, choice of location for offshore wind farms, development of new interconnections, location of new nuclear reactors, possible shutdown of certain nuclear reactors, demand flexibility for electric mobility or hydrogen production, etc.). RTE has indicated that the study of these drivers on investment needs will be carried out between now and the final publication of the SDDR.

- CRE supports RTE's strategy of retaining network reinforcement projects that offer benefits in all the scenarios studied, including those with lower levels of electrification.
- Some no-regret projects have already been launched by RTE to meet specific needs. Other projects will need to be confirmed in the coming years depending on the dynamics of the energy transition. For the latter, CRE is currently considering asking RTE to include a scenario of more pronounced delay in electricity consumption growth in its studies.
- The most significant projects, costing more than €200 million, will be approved individually by CRE.

***Question 1313** Do you agree with CRE's analysis of the strategy for strengthening the very high voltage network presented in the SDDR?*

9.2. Investments needed to meet new voltage management challenges

For the first time in its SDDR, RTE has carried out specific analyses and quantified the investment expenditure required for voltage management on the transmission network. A comparison with the development plans of other European countries shows that RTE is one of the only network operators to provide such detailed analyses. CRE considers that these studies constitute a real improvement to the SDDR and should be continued in future editions.

In its SDDR, RTE forecasts €1.9 billion in investment expenditure on voltage control measures:

- €1.4 billion for the installation of inductors[42] for the management of high voltage phenomena;
- €0.3 billion for the installation of capacitors to manage low voltage phenomena;
- €0.2 billion for the installation of static compensators (STATCOM) to manage stability issues.

These investments are intended to address the issues anticipated by RTE concerning voltage management in the coming years. In particular, RTE has observed an increase in the frequency of high voltage phenomena and expects this to worsen over the period 2025-2039. There are many reasons for this upward trend in high voltage phenomena: the undergrounding of the network, changes in usage,

[42] inductors are high-voltage electrical components consisting of cable windings.

and an increase in the frequency of periods of low consumption or high renewable production, leading to low transits in the transmission network infrastructure.

RTE is therefore proposing a three-pronged plan:

- the installation of 210 additional inductors needed to manage high voltage phenomena by 2040. This programme is based on prospective studies for 2030 and a national assessment for 2040. Uncertainties about the location of production and consumption at that time make it impossible to carry out detailed studies;
- increased participation by producers, particularly renewable energy producers, connected to the RPT for static compensation when they are not producing;
- a reduction in reactive energy injections from distribution networks, including, in particular, the widespread implementation of instructions for reactive absorption by producers connected to the distribution network and the implementation of compensation measures.

CRE considers that the programme of investment in voltage control measures proposed by RTE is consistent with the anticipated injection of reactive energy into the transmission network, which is the main driver of the increase in high voltages. This programme is significant and will lead to a threefold increase in the network's control capacity.

The prospective studies carried out by RTE for 2030 incorporate various scenarios for renewable energy consumption and production, but are based on fixed assumptions simulating reduced availability of the control provided by nuclear and hydroelectric power stations. They also do not take into account the possible unavailability of already installed control resources. RTE has already begun work to improve the robustness of the studies carried out for high voltage management and has produced other variants on its analyses. CRE believes that this work should be continued, in particular by including a probabilistic estimate of the availability of generation and control resources, consistent with the history observed in recent years. Furthermore, the risk threshold requiring the installation of new control resources, set at 10 hours/year in these studies, should be re-examined on the basis of a technical and economic analysis.

Developments relating to the increased participation of producers, storage operators and distribution network operators in voltage control will be the subject of consultations in the coming months. These consultations could lead to changes in the rules governing remuneration for medium-voltage voltage control, which are approved by CRE. RTE estimates that these developments would avoid around €650 million in investments in voltage control resources. These gains are significant compared to the additional costs envisaged for the remuneration of the users concerned (the total amount of the synchronous compensation service on the transmission network is currently around €5 million/year).

> - The constraints associated with high voltage phenomena will increase in the coming years. Managing these situations will require (i) significant investment in the transmission network, corresponding to a threefold increase in the adjustment resources available on the RTE network, (ii) greater involvement of producers and storage operators, particularly those capable of providing static compensation, as well as distribution network operators in voltage adjustment.
> - The rules relating to voltage management and their effective implementation by all stakeholders will need to evolve in the coming years. CRE supports the consultations launched by RTE in this regard. This mobilisation would avoid around €650 million in additional investment over the SDDR period.
> - At this stage, CRE is considering asking RTE to continue the work it has begun to improve the methodology used to study investment needs in new voltage control means, in particular by taking into account a wider range of electricity system configurations.

In its SDDR, RTE also identifies the installation of 34 additional capacitors needed to manage low voltage phenomena in the medium term (beyond 2030). This identification is not based on simulations, and RTE will carry out more detailed technical and economic studies in the coming years to confirm this result.

Finally, the trajectory proposed in the SDDR includes the installation of two STATCOMs to address issues related to grid stability due to interactions between converters in renewable energy production parks. RTE anticipates a challenge around this phenomenon in the medium term (beyond 2030) on the transmission grid. Further studies will be necessary to justify the installation of these measures and their location. These studies will also need to incorporate the new requirements of the RfG code[43] , following its revision, particularly with regard to the operation of renewable energy producers in grid-forming mode.

> ➢ Further studies will be needed to confirm the need for the investments proposed by RTE for low voltage management and grid stability.

> ***Question 1414*** *Do you agree with CRE's analysis of the investments needed for voltage management?*

10. A trajectory based on the use of overhead technology to control costs

10.1. The necessary use of overhead technology in HTB 3

10.1.1. A strategy based on the priority use of existing overhead corridors

The strategy for strengthening the HTB 3 (400 kV) network presented by RTE in part 9 is based on the use of overhead technology for all the planned HTB 3 network reinforcement projects. Only the "Gironde – Loire-Atlantique" project is envisaged using submarine technology due to the possibility of combining this project with the connection of offshore wind farms.

For these projects, RTE is prioritising the use of existing overhead corridors to facilitate their integration. Thus, two of the three projects selected by RTE for the first reinforcement phase (see 9.1.1) do not involve the creation of overhead lines in greenfield sites. Similarly, for the second phase (see 9.1.2), the vast majority of the projects envisaged do not involve the creation of lines in greenfield sites, but rather increases in the capacity of existing lines or the doubling of lines in parallel with existing corridors.

However, some upgrades will require the creation of new overhead lines in greenfield sites, in cases where the existing network does not allow the use of existing corridors. This is the case for the project to create a line between Fos-sur-Mer and Jonquières planned by the SDDR.

10.1.2. A strategy necessary for consumer sustainability

The choice of overhead technology is an economic necessity: an exclusively underground strategy would require the use of direct current technology[44] , and would generate significant additional costs. The cost of creating an overhead line of approximately 100 km with a transmission capacity of around 4 GW is between €250 and €400 million[45] , compared with nearly €4 billion for an underground line of the same length and capacity. Underground technology at this voltage level can therefore be up to 10 times more expensive than overhead technology. For the entire SDDR, a fully underground solution for very high voltage would represent an additional cost of around €40 to €70 billion for an identical service, whereas the cost of overhead upgrades to the THT network is estimated at around €8 billion over the

[43] European Commission Regulation (EU) 2016/631 of 14 April 20161 known as "*Requirement for generators*" or RfG

[44] Underground lines at 400 kV voltage levels may exist for very short distances, for example in the vicinity of electrical substations. These short distances nevertheless require the use of additional means of reactive energy compensation.

[45] Depending on the cost of integration measures, see 6.2.1.

period 2025-2039. Furthermore, tensions over the supply of direct current equipment call into question the very feasibility of such a solution.

At this stage, CRE considers that the strategy proposed by RTE is relevant and represents the best technical and economic balance between the solutions. In particular, the preferential use of existing line corridors will facilitate the integration of new projects. For new projects on greenfield sites, the use of overhead technology is justified in view of the cost difference with underground direct current technology.

- ➢ CRE supports RTE's proposal to favour overhead technology for the reinforcement of the very high voltage network.
- ➢ The systematic use of underground direct current technology would entail very significant additional costs, in the order of €40 to €70 billion over the period 2025-2039, for the reinforcement of the very high voltage network planned by the SDDR to support the growth in electricity consumption. Such additional costs would not be economically sustainable for electricity network users. The creation of new 400 kV overhead lines therefore appears necessary to support the growth in electricity consumption.

Question 1515 *Do you agree with CRE's analysis on the use of overhead technology to strengthen the very high voltage network?*

10.1.3. Integration measures to be tailored on a case-by-case basis

The creation, reconstruction or reinforcement of overhead lines is accompanied by integration measures implemented by RTE to offset their impact on the environment and facilitate their acceptance by the population. Some of these integration measures are mandatory (compensation for permanent damage, compensation for visual damage, etc.), while others are determined on a case-by-case basis following consultations (burying surrounding lines underground, installing aesthetic pylons, buying back houses, etc.). These expenses represent around one third of the total expenses (supplies and works) for the latest 400 kV line creation projects carried out by RTE.

In addition to existing measures, when it is not possible to use an existing line corridor, RTE proposes in the SDDR to systematically accompany the construction of new 400 kV overhead lines on greenfield sites by burying lower voltage networks in the surrounding area for at least an equivalent length.

CRE supports the implementation of integration measures by RTE, including optional measures. These measures reduce the environmental impact of projects and speed up their completion. However, at this stage, CRE considers that it is not appropriate to systematically bury an equivalent length of cable when creating new 400 kV overhead lines on greenfield sites. Such a measure could generate significant additional costs, estimated by CRE at around €400 million over the SDDR period, without being necessary for the local integration of the projects in question. CRE considers instead that the choice of integration measures should be made on a case-by-case basis, depending on the characteristics of the area and consultation with stakeholders. The undergrounding of lower voltage networks should remain one of several solutions to be considered during these consultations.

- ➢ CRE supports the implementation of integration measures by RTE to reduce the impact of projects and facilitate their acceptability. The choice of integration measures, which represent a significant part of the costs of projects to create these lines, must be made on a case-by-case basis in order to select those best suited to each project. CRE is therefore opposed, at this stage, to RTE's proposal to systematically bury low-voltage networks for a length at least equivalent to that of a new extra-high-voltage overhead line outside existing line corridors.

Question 1616 *Do you agree with CRE's analysis of the need to tailor the integration measures for 400 kV projects on a case-by-case basis, depending on local specificities?*

10.2. Choice of technology in HTB 1 and HTB 2

10.2.1. Cost differences between overhead and underground technologies

Unlike the 400 kV network, undergrounding the HTB1 (63-90 kV) or HTB 2 (150-225 kV) voltage networks does not require the use of direct current technology. The additional cost of undergrounding the HTB 1 and 2 networks is therefore lower than for HTB 3:

- for the HTB 1 network, the additional cost associated with undergrounding a line ranges from a few per cent for a line with moderate capacity in rural areas to +70% for a line with high capacity (requiring the construction of a double underground connection) in semi-urban areas;
- for the HTB 2 network, the additional cost associated with undergrounding is higher: it ranges from +50% for a moderate-capacity line in a rural area to +150% for a high-capacity line in a semi-urban area.

The cost of constructing an underground connection therefore remains higher than for an overhead connection in HV 1 and HV 2, although this additional cost is limited compared to the HV 3 network.

10.2.2. The use of underground technology should be considered when it offers sufficient benefits in relation to the costs.

In its deliberation examining the SDDR developed in 2019[46] , CRE asked RTE to follow the following policy for undergrounding HTB 1 and 2 networks:

- for the HTB 1 network, preferential use of underground lines in areas identified by the 2017 public service contract (areas of concentrated housing and natural importance) and after case-by-case analysis in other areas;
- for the HTB 2 network, possible use of underground lines only in areas identified by the public service contract.

In its SDDR 2025, RTE envisages several developments in this undergrounding policy:

- systematic use of underground technology for HTB 1 and HTB 2 connection works (excluding connections of less than 1 km), due to shorter commissioning times;
- preferential use of underground technology for HTB 1 and HTB 2 in urban areas and in certain areas of environmental concern, following a case-by-case analysis. The environmentally sensitive areas concerned are the cores of national parks, areas covered by decrees protecting biotopes, geotopes or natural habitats, biological reserves, central biosphere areas, national, regional or wildlife reserves, specially protected areas of Mediterranean importance, Natura 2000 areas, coastal or natural area conservatories, and sensitive natural areas;
- in HTB 1 only, systematic use of underground technology for the creation of new lines of moderate capacity (not requiring the creation of a double underground line) as the associated additional cost is low.

At this stage, CRE considers that the changes to the doctrine of undergrounding HTB 1 and 2 lines proposed by RTE are relevant.

With regard to connection works, reducing delays is a key issue in the implementation of projects. As these works are mainly financed by the applicants, CRE plans to ask RTE to inform the applicant, when drawing up the technical and financial connection proposal, of the existence of a more economical overhead solution (reference solution) and, where applicable, a faster underground solution (alternative solution). RTE's policy does not apply to any shared infrastructure or upgrades to the existing network planned under S3REnR or in shared areas, which do not necessarily present the same challenges in terms of completion times.

[46] CRE deliberation of 23 July 2020 examining the Ten-Year Development Plan for the RTE Transmission Network drawn up in 2019.

CRE is in favour of placing medium-capacity HTB lines underground, as the additional costs compared to overhead technology appear to be limited.

Finally, CRE plans to ask RTE to submit, when sending its annual investment programme, a review of all new underground line creation projects and the associated justifications (project characteristics, solutions studied, case-by-case analysis), in order to monitor the implementation of this policy.

> - At this stage, CRE is in favour of undergrounding HTB 1 and 2 networks in the following cases: i) urban areas, ii) connections longer than 1 km (subject to RTE providing the applicant information on the differences in cost and time compared to an overhead solution), iii) areas with significant environmental issues after case-by-case analysis, and iv) creation of medium-capacity HTB 1 lines (single line).
> - CRE also supports RTE's proposal to favour overhead technology in other cases for the renewal and adaptation of HTB 1 and HTB 2 networks. This strategy is justified by significant cost differences between the technologies: underground cables incur additional costs of around +70% for a high-capacity HTB 1 line, and around +50% to +150% for HTB 2.

Question 1717** Are you in favour of the criteria for underground installation envisaged for the HTB 1 and 2 networks**?

11. Development of interconnections

Interconnections are an essential component of the European internal energy market. Due to its geographical position and electricity mix, France plays a central role in the functioning of the European electricity market. Beyond their fundamental benefits in terms of economic optimisation and security of supply, interconnections promote the integration of intermittent renewable energies by taking advantage of complementarities between countries.

11.1. The benefits of projects currently under development for commissioning by 2030 are confirmed

Five interconnection projects between France and neighbouring countries are currently under development for commissioning by 2030:

- the Celtic submarine direct current interconnection project with Ireland, scheduled to come on stream in 2028, which will increase the exchange capacity between France and Ireland from 0 to 700 MW ;
- the Bay of Biscay submarine direct current interconnection project with Spain, scheduled to come on stream in 2028, which will increase the exchange capacity between France and Spain from 2,800 MW to 5,000 MW (see 11.2.1.1) ;
- interconnection projects with Germany, most of which are located outside France,
  - Muhlbach – Eichstetten, scheduled to come on stream in 2030 and expected to increase the exchange capacity between France and Germany by 300 MW ;
  - Vigy – Uchtelfangen, scheduled to come on stream in 2029 and expected to increase the exchange capacity between France and Germany by 500 MW for imports and 1,500 MW for exports ;
- the Lonny-Achêne-Gramme interconnection project with Belgium, scheduled to come on stream between 2030 and 2032, which should increase the exchange capacity between France and Belgium by 800 MW for imports and 1,000 MW for exports.

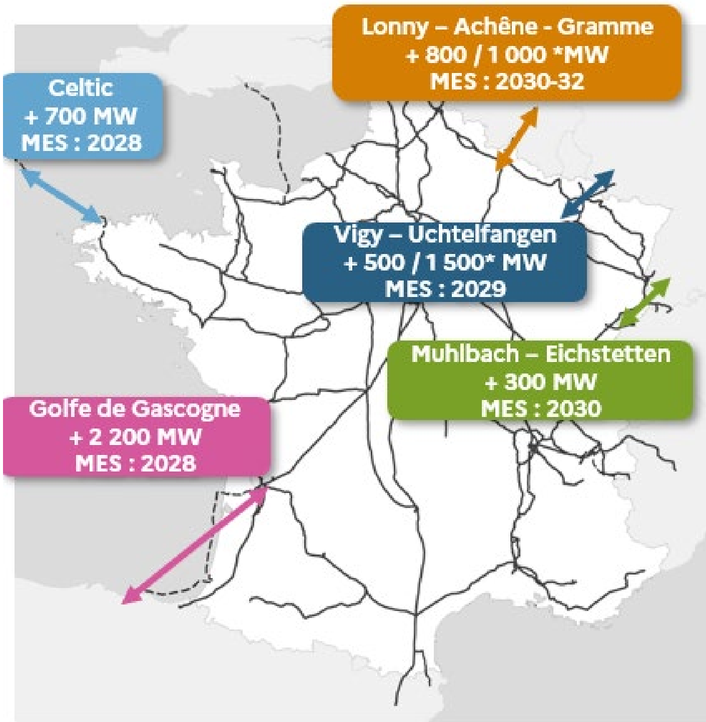

Figure 11. Map of the five interconnection projects currently under development

In its SDDR 2025, RTE confirms that these projects will bring economic benefits. In its deliberations of 3 November 2022[47] and 2 March 2023[48] , CRE approved the continuation of the Celtic and Bay of Biscay projects on the basis of the new cost-sharing arrangements agreed with the regulators of the countries concerned.

The projects with Germany and Belgium were not subject to a specific decision on approval or cost sharing with neighbouring countries because they have low costs[49] and consist of reinforcements to the existing network.

> ➢ The five interconnection projects currently under development (Celtic, Bay of Biscay, Muhlbach-Eichstetten, Vigy-Uchtelfangen, Lonny-Achêne-Gramme) offer significant benefits and must be completed as soon as possible.

> ***Question18 8*** *Do you agree with CRE's analysis of the interconnections under development?*

11.2. The development of new projects must be analysed in light of changes in project costs and constraints on internal networks

In its SDDR, RTE conducted in-depth analyses of the economic benefits of new interconnections and the possible conditions for their integration into the network. These analyses are based on scenarios A and B of the SDDR presented in section 3.1.

[47] CRE deliberation of 3 November 2022 adopting the decision to review the joint decision on the cross-border allocation of costs for the Celtic project

[48] CRE deliberation of 2 March 2023 amending the joint decision on cross-border cost allocation for the Gulf of Biscay project

[49] Muhlbach-Eichstetten: €148 million; Vigy-Uchtelfangen: €144 million; Lonny-Achène-Gramme: €148 million (the majority of the costs are borne by the neighbouring TSO)

11.2.1. Constraints on internal networks must be taken into account in the development of new interconnection projects

The interconnection capacities made available to the markets fluctuate daily depending on the transit capacities available in the internal networks. Thus, the interconnection capacities actually used are not always equal to the maximum technical capacities of the cross-border lines, and it is often the case that the internal network is the limiting factor for cross-border exchanges.

Depending on the location of the limiting network constraints, strengthening the internal network can be as effective, if not more so, in increasing cross-border exchange capacity than a new interconnection line project.

In its SDDR, RTE has conducted in-depth studies at the border with Spain which demonstrate the importance of taking internal network constraints into account when studying new interconnection projects. In its SDDR, RTE therefore considers that the development of new interconnections requires simultaneous reinforcement of the French internal network.

At this stage, CRE considers that the analysis carried out by RTE is relevant and notes that such analyses are not carried out during the preparation of the TYNDP (see 11.3.3). The planned transformations of energy systems suggest that constraints on the internal networks of European countries are likely to increase, which could be a limiting factor for cross-border exchanges. From this perspective, prospective studies of changes in exchange capacity should be extended to all borders and be the subject of joint studies with RTE's counterparts in the countries concerned.

> ➢ CRE supports the development of interconnections in an approach that integrates internal network upgrades in the countries concerned. CRE stresses the importance of taking into account internal network constraints and actual market coupling mechanisms in prospective studies.

11.2.2. The development of new projects requires adequate funding

CRE supports the development of new interconnection projects when they offer benefits at European level. Indeed, the implications of developing a new interconnection can only be assessed at the level of the European interconnected system as a whole.

However, this assessment does not guarantee economic balance for the countries financing the interconnection, as it may lead to changes in the production mix in several other countries. Due to its geographical location and numerous interconnections, France may find itself in a situation where it acts as a transit country for electricity exchanges from the Iberian Peninsula or the United Kingdom to Eastern Europe.

In its assessments of interconnection projects, CRE has consistently considered that the cost-benefit analysis of projects must also be positive within France. When the distribution of the expected benefits of a new interconnection does not guarantee economic balance for each country, CRE considers that a distribution of funding between states and/or the obtaining of European subsidies appears necessary in order to guarantee the balance.

> ➢ CRE supports the development of profitable interconnection projects within Europe and France. This profitability can be achieved through asymmetric sharing of project investment costs or through European funding.

11.2.3. France-Spain border

The 2015 Madrid Declaration, following the Energy Interconnection Summit, provided for the achievement of an initial exchange capacity between France and Spain of 5 GW with the commissioning of the Bay of Biscay project, followed by the development of two interconnection projects crossing the Pyrenees, the trans-Pyrenean projects, in order to increase interconnection capacity to 8 GW.

11.2.3.1. Achievement of the 5 GW exchange level

In its SDDR 2025, RTE has carried out new studies on the evolution of interconnection capacity between France and Spain in the coming years. These studies incorporate the latest forecasts for consumption and production trends in France and Europe, as well as network reinforcement projects currently under development.

Taking into account the network upgrades planned between now and 2030, RTE estimates that the maximum capacity of 5 GW would be far from being reached at all times. However, several upgrades to the French internal network planned in the SDDR would make it possible to achieve 5 GW of exchange capacity at least 70% of the time[50]. These upgrades include several projects to rehabilitate or build 400 kV overhead lines in south-western France and the Massif Central. These projects are scheduled to come on stream between 2030 and 2035 in the SDDR.

The RTE study could only be carried out within France, but it seems very likely that reinforcements will also be necessary in Spain. CRE therefore supports the completion of a joint study between the French and Spanish network operators on the conditions for achieving and maintaining a 5 GW exchange capacity at the border.

11.2.3.2. Trans-Pyrenean projects

The trans-Pyrenean projects are two 2 GW direct current projects with a voltage of 320 kV, which should increase exchange capacity by 3 GW. Given the market conditions for direct current equipment, the cost could reach €2.5 to €3 billion per project[51]. Based on data provided by RTE, CRE estimates that a new project design, with a capacity of 1.5 GW and a voltage of 525 kV, would reduce the cost to around €2 billion per project. However, this design change would require a review of all the studies carried out to date and could lead to an increase in exchange capacity of less than 3 GW. There are also uncertainties regarding the costs of 525 kV technology, which will need to be updated in light of RTE's calls for tenders for offshore wind farm connections.

RTE has also conducted studies on the conditions for integrating trans-Pyrenean projects into the existing grid. As in the case of the Bay of Biscay, these studies were only conducted for the French grid. In the case of a first trans-Pyrenean project, additional upgrades (creation or refurbishment of several 400 kV lines) planned in the SDDR between 2035 and 2040 are necessary to reach 6.5 GW most of the time. At this stage, CRE considers that the planning of these reinforcements must be a prerequisite for the implementation of an initial trans-Pyrenean project.

Finally, RTE has analysed the benefits of trans-Pyrenean projects (provided that they actually enable creation of exchange capacity). These analyses show significant benefits, between approximately €190 million and €220 million per year per GW of additional capacity[52] . A new interconnection would thus make it possible to better exploit surplus renewable production in Spain (mainly solar production during the day) and reduce the use of thermal production (mainly at night). Analyses carried out by RTE show that Spain would benefit from 75% of the socio-economic benefits generated by a new interconnection. In particular, imports from Spain would be partly re-exported to other European countries, confirming the trend currently observed[53]. This distribution would therefore raise the question of an asymmetric sharing of the costs of a new project.

However, the results obtained by RTE in its SDDR appear to be lower than those of the TYNDP 2024, which estimates the socio-economic benefits for 1 GW of new capacity at around €300 million per year. CRE notes that this discrepancy could be due to erroneous assumptions about hydrogen production by

[50] It should be noted that when prices converge, exchange capacity is not used to its full potential. In 2024, prices converged 32% of the time on the France-Spain border.

[51] This cost is higher than that reported by project developers in the TYNDP 2024 (€2.3 billion per project) due to recent increases in the cost of direct current equipment.

[52] For an initial project. To facilitate comparisons, all analyses in this document have been standardised for 1 GW of additional capacity created.

[53] In its electricity balance sheet for 2024, RTE highlighted that the proportion of imports from the Iberian Peninsula crossing France to other European countries exceeded 90%.

electrolysis in the TYNDP. In addition to studies on internal networks, CRE supports joint studies between French and Spanish network operators on the benefits of these projects.

- Increasing exchange capacity between France and Spain, in particular through the implementation of the Bay of Biscay and trans-Pyrenean projects, is a strategic priority at European level.
- CRE considers that RTE must, as a matter of priority, work with its Spanish counterpart to improve the achievement of the maximum 5 GW exchange capacity after the Bay of Biscay project comes into service.
- The two trans-Pyrenean projects are very costly (around €2 to €3 billion per project). These costs must be reassessed in light of the latest calls for tenders for the supply of direct current equipment. Optimising the design of the projects could reduce costs, but these developments will require further studies.
- Significant upgrades to internal networks must be planned prior to the commissioning of trans-Pyrenean projects. For the first project, this would require to build or upgrade several 400 kV lines. A coordinated study between French and Spanish network operators will be necessary to identify the upgrades required on both sides of the border.
- Analyses of the benefits of trans-Pyrenean projects show significant differences in assumptions and results**.** New studies should be carried out and shared between network operators to confirm these results.
- If prospective studies confirm that the benefits remain skewed in favour of Spain, CRE considers it necessary to consider an asymmetric cost sharing of the costs of these projects.

11.2.4. France-United Kingdom border

In March 2024, CRE published an assessment of the benefits of a new interconnection with the United Kingdom[54] . This study concluded that a new interconnection of approximately 1 GW between the two countries would be economically beneficial, provided that the project costs were shared asymmetrically in order to compensate for the insufficient benefits for France.

The SDDR confirms the trend highlighted in the March 2024 analysis. By 2040, a new interconnection between France and the United Kingdom would derive its economic value mainly from exports of surplus carbon-free electricity production in the United Kingdom (mainly wind power) to continental Europe. This production would replace thermal production in countries with a more carbon-intensive mix than France (Italy and Germany in particular) and would increase hydrogen production through flexible electrolysis (in France and Spain in particular). This would represent a radical change in the use of interconnections with Great Britain, which currently operate mainly to export electricity from France to the United Kingdom.

From a quantitative point of view, the SDDR estimates the benefit of a new interconnection at between €278 million/year and €306 million/year for 1 GW of additional capacity by 2040, which is a significant increase compared to the value published by CRE in 2024. This change comes from a better valuation of renewable energy surpluses from the United Kingdom, particularly through flexible hydrogen production.

At the same time, RTE has noted an increase in the costs of a new project using direct current technology. This reassessment is based on contracts signed in 2024 and 2025 for the supply of identical equipment for offshore wind farm connections. This increase amounts to +54% compared to the costs considered in the 2024 study.

In light of these new analyses, CRE considers that a new project would remain beneficial at European level. However, the benefits of such a project for France would be much less than for the United Kingdom. In order to ensure the profitability of a new project for France, CRE considers that RTE should

[54] Public consultation no. 2024-01 of 5 March 2024 on the advisability of new electricity interconnection capacity between France and the United Kingdom

not bear more than 30 - 40% of the investment costs of a new project (assuming a 50/50 split of interconnection revenues and based on the project costs estimated by RTE).

> - In its public consultation in March 2024, CRE concluded that a new interconnection of around 1 GW could be of interest at European level. This economic assessment made in 2024 is dependent on the cost escalations observed for new projects and the increase in projected profits in the new energy mix scenarios.
> - The SDDR confirms the need for asymmetric cost sharing for a new project, with profits mainly coming from the valorisation of surplus renewable production in the United Kingdom. At this stage, a new project would only be profitable for France if France bore only between 30 and 40% of the investment costs (assuming a 50/50 split of interconnection revenues).
> - CRE and Ofgem are continuing their discussions on the conditions necessary for the construction of a new interconnection. The regulators have also committed to conducting a joint study in the longer term on the advisability of a new interconnection between the United Kingdom and France.

11.2.5. France-Ireland border

In its SDDR, RTE examined the benefits of increasing interconnection capacity with Ireland beyond the commissioning of the Celtic interconnection.

The benefits of a new interconnection could be significant, particularly given the relatively low level of interconnection between Ireland and the European continent. However, an interconnection between France and Ireland would particularly long, with 575 km for the Celtic project, compared to an average of 180 km for a new interconnection with the United Kingdom. Due to the costs escalations on the DC equipment supply markets and the length required to connect Ireland to France, a new interconnection would be particularly costly (around €4 billion in investment for a project of approximately 1 GW).

> - Given the particularly tense situation on the market for the supply of equipment for the construction of a new submarine interconnection, the continued development of interconnections between France and Ireland does not appear to be a priority.

11.2.6. Borders between France and Germany, Belgium and Switzerland

In its SDDR 2025, RTE did not conduct a detailed analysis of internal grid upgrades that would increase exchange capacity at the borders with Germany, Belgium and Switzerland. At this stage, CRE considers that such analyses are a priority. Indeed, capacity limitations in the French network, particularly for exports, are mainly due to interconnection facilities currently being upgraded or to the internal network. Internal upgrades could therefore create exchange capacity at a reduced cost.

With regard to possible new interconnection projects, the SDDR shows that the benefits of increasing interconnection capacity between France on the one hand and Germany, Belgium and Switzerland on the one hand and Switzerland on the other, could be significant in a scenario where the public energy objectives of the various countries are achieved (between €111 and €273 million/year depending on the borders for a capacity of 1 GW in scenario A by 2040). These benefits would mainly come from additional exports of surplus carbon-free production in France (nuclear/renewable) to neighbouring countries.

However, these benefits would be significantly lower in a scenario of lower consumption growth in the various European countries (between €59 and €129 million/year depending on the borders for a capacity of 1 GW in scenario B by 2040).

In addition, the construction of new interconnection facilities may require the use of direct current technology due to geographical constraints or acceptability on both sides of the border.

In view of these uncertainties, CRE considers at this stage that priority should be given to strengthening internal networks to increase exchange capacity at the borders with Germany, Belgium and Switzerland. Projects of new interconnection lines will require further studies on the associated costs and benefits.

> ➢ CRE plans to ask RTE to identify projects to strengthen the internal network in order to increase or maintain exchange capacity at the borders with Germany, Belgium and Switzerland. The impact of these projects on exchange capacity should be analysed jointly by RTE and the various network operators concerned.
>
> ➢ At these borders, projects of new interconnection lines must be analysed in further studies on the associated costs and benefits.

11.2.7. France-Italy border

As with the borders with Germany, Belgium and Switzerland, CRE considers that RTE should identify projects to strengthen the internal network in order to increase or maintain exchange capacity at the Italian border. These projects could enable exchange capacity to be created at a reduced cost.

With regard to new interconnection projects, the SDDR shows an economic interest in increasing interconnection capacity between France and Italy. Adding new interconnection capacity would primarily enable thermal power generation in Italy to be replaced by carbon-free French power generation (nuclear and renewable). The economic benefits of a new interconnection could thus reach between €182 and €326 million per year for a new exchange capacity of 1 GW by 2040. Significant benefits are anticipated in all scenarios (achievement of public targets or lower consumption growth), due to the limited level of interconnection between the two countries and the complementary nature of their electricity mixes.

Nevertheless, the costs of new projects remain uncertain at this stage and the internal network upgrades required for their integration will need to be studied in advance.

> ➢ CRE plans to ask RTE to identify projects to strengthen the internal network in order to increase or maintain exchange capacities on the border with Italy, and to carry out joint analyses with the Italian transmission system operator.
>
> ➢ Creation of a new interconnection line could be economically beneficial by 2040, but it would require (i) additional studies of the internal network to ensure that a new structure would actually increase exchange capacity and (ii) a detailed cost estimate for the project and associated upgrades.

> ***Question 1919** Do you agree with CRE's analysis of the opportunities for developing new interconnections?*

11.3. Consistency of SDDR results with the TYNDP

Pursuant to Article L. 321-6 of the Energy Code, CRE verifies the consistency between the SDDR and the non-binding *Ten-Year Network Development Plan* (TYNPD) for the European network.

The TYNDP is drawn up by ENTSO-E in accordance with European Regulation (EU) 2019/943. In case of doubt, CRE may consult ACER. It may also impose a modification of the SDDR.

11.3.1. The comparison with the scenarios selected in the SDDR focuses on scenarios that are consistent with public policy objectives.

The TYNDP 2024 scenarios were developed jointly by ENTSO-E and ENTSO-G and propose several visions of the future for 2030, 2040 and 2050.

- The "*National Trends* (NT)" scenario has been developed for the 2030 and 2040 timeframes. It corresponds to the scenarios envisaged by the energy and climate policies resulting from European objectives. This scenario has been developed for the 2030 and 2040 timeframes only.
- The "*Distributed Energy* (DE)" scenario is based on achieving carbon neutrality targets by 2050 while aiming for a high level of independence in terms of energy supply and strategic goods

(e.g. industrial and agricultural products). It results in a change in behaviour and a strong drive towards decentralisation.

- The "*Global Ambition* (GA)" scenario describes a path to carbon neutrality by 2050 through rapid, global transition. It involves the large-scale development of a wide range of technologies and significant use of carbon-free energy exchanges between countries. The results of this scenario are not published in the TYNDP 2024.

The *DE* and *GA* scenarios are constructed by ENTSO-E and ENTSO-G on the basis of a distribution key for European decarbonisation and renewable production targets. By design, these scenarios lead to trajectories that do not correspond to the objectives of Member States, particularly for France. For example, the total solar and wind power capacity (onshore and offshore) forecast in the *DE* scenario for 2040 is 230 GW in France, compared with 160 GW in scenario A and 125 GW in scenario B of the SDDR.

CRE considers it relevant at this stage to compare the *NT* scenario, based on the energy policies of different countries, only with scenario A of the SDDR[55]. It is also regrettable that European Regulation 2022/869 on trans-European energy infrastructure does not provide for the study of scenarios of delays in achieving public objectives, similar to scenario B studied by RTE.

11.3.2. The assumptions of the *National Trends* scenario are broadly consistent with those of the SDDR, but the results of these two scenarios differ significantly.

CRE's analysis focused on comparing the *NT* scenario with scenario A of the SDDR. For simplicity, the data are presented below for the 2040 deadline only.

The consumption assumptions are relatively similar between the two scenarios for the various European countries. However, the *NT* scenario of the TYNDP 2024 forecasts higher electricity consumption in France by 2040, in the order of 615 TWh (i.e. +34, TWh) excluding hydrogen production by electrolysis. This result is mainly due to greater electrification and fewer energy efficiency efforts in this scenario.

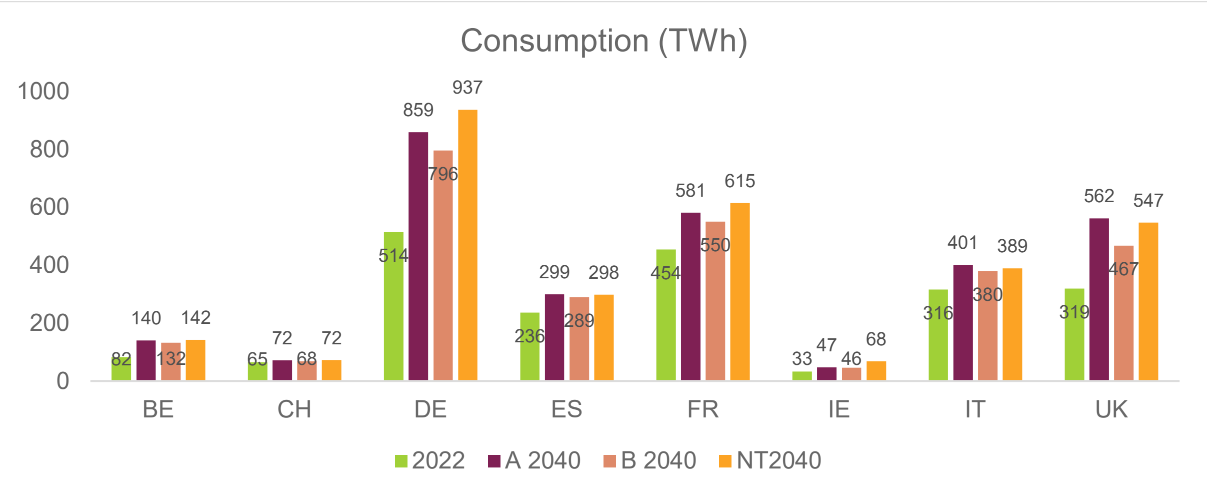

Figure 12. Electricity demand (excluding hydrogen production by electrolysis) in the TYNDP National Trends scenario and SDDR scenario A, by 2040

Furthermore, the methodology used to model hydrogen production by electrolysis differs between the two studies, with the TYNDP choosing to model an interconnected hydrogen network between different European countries, while the SDDR model is based on a price limit above which production is not competitive.

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[55] The data on assumptions for France was submitted two years before the TYNPD exercise, and some data differs from the data in scenario A of the SDDR.

The assumptions regarding installed renewable energy capacity in the SDDR's *NT* and A scenarios are similar. However, the load factors used in the two scenarios differ, particularly for wind power in the United Kingdom and Germany. The SDDR uses load factors based on historical data from recent years, while the TYNDP anticipates significant technological progress in these countries. For example, the load factor used for onshore wind power in Germany is 28% for the TYNDP, compared with 22% in the SDDR. This leads to a fairly significant production gap of around +700 TWh at European level for the TYNDP's *NT* scenario in 2040, despite broadly identical production capacities.

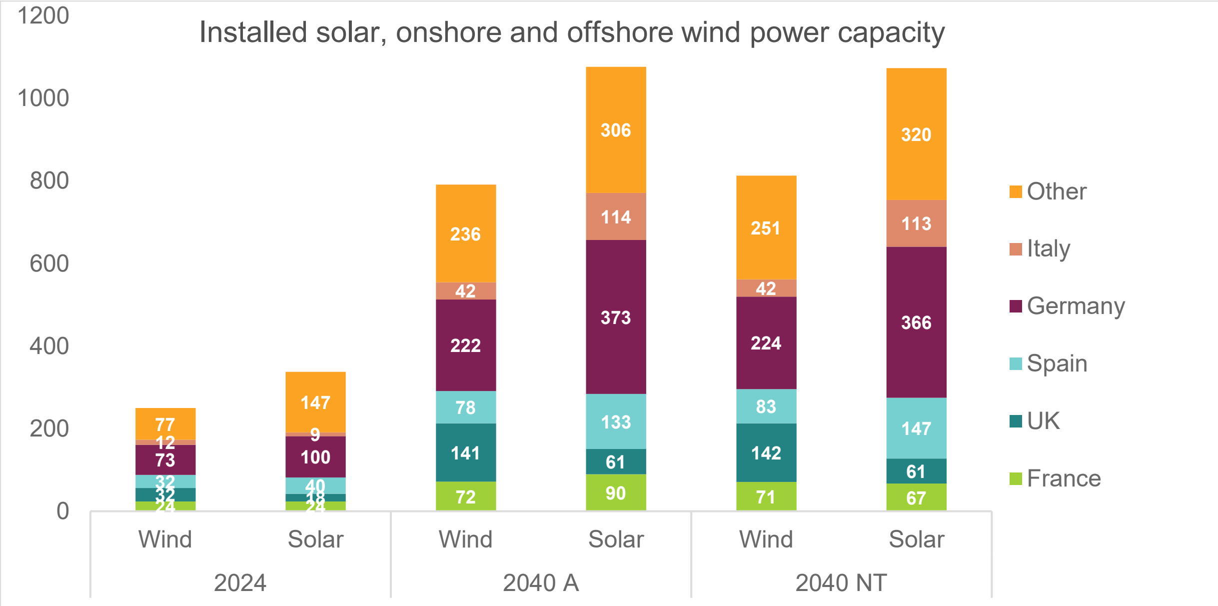

Figure 13. Installed solar, onshore and offshore wind power in 2024, in the National Trends and A scenarios of the SDDR for 2040.

Finally, in terms of cross-border electricity exchanges, France appears to be a very slight importer in the TYNDP 2024 *NT* scenario, with a negative balance of 7 TWh (119 TWh of imports s and 112 TWh of exports). *Conversely,* France remains a major exporter in the SDDR's A scenario, with a positive balance of 101 TWh (34 TWh of imports and 136 TWh of exports), in line with France's export balance in recent years (89 TWh of net exports in 2024).

In conclusion, CRE notes that the two scenarios present different visions of how to achieve public objectives. The TYNDP's *NT* scenario forecasts a greater increase in consumption in France and higher renewable production in neighbouring countries, leading France to be a slight net importer of electricity. Furthermore, the assumptions used in the TYNDP's *NT* scenario concerning hydrogen production by flexible electrolysis, particularly in Spain, warrant further analysis (see 11.2.1).

11.3.3. The identification of interconnection needs in the TYNDP is not directly comparable to the cost-benefit analyses carried out for the approval of investment projects.

The *IoSN* (*Identification of System Need*) component of the TYNDP identifies additional interconnection capacities that could offer benefits within the timeframe considered. For France, the TYNDP identifies an economic space for 24 GW of additional interconnection capacity by 2040 compared to existing capacity, compared to approximately 6 GW of new capacity planned in RTE's SDDR.

At this stage, CRE considers that the *IoSN* exercise presents methodological biases leading to significant differences between these results and a real cost-benefit assessment of the projects:

- The investment costs of the projects correspond to the values declared by the project promoters or to unit cost estimates based on data reported by the project promoters. These cost estimates may be significantly underestimated in view of current market conditions for direct current interconnections.

- The socio-economic studies carried out do not take into account the geographical distribution of benefits between countries: they do not ensure that all countries affected by the investments will derive economic benefits.
- The TYNDP does not take into account the internal network constraints of countries: new interconnections are assumed to provide fixed capacity throughout the year and congestion costs related to internal constraints are ignored.
- The TYNDP analyses include the monetisation of two additional indicators, the methodologies for which appear questionable:
  - valuation of the benefits associated with security of supply: the public objectives of European countries generally provide for electricity mixes with excess capacity and, under these conditions, the additional value provided by new interconnections for security of supply is generally low. The TYNDP indicators for security of supply are calculated on the basis of fictitious energy mixes, with a reduction in peak capacity. The results of this methodology therefore depend on arbitrary choices regarding energy mixes[56] .
  - valuation of CO_2 emissions reductions at their guardian value: the calculation of socio-economic benefits already includes a valuation of emissions at their market value in the production costs of the various power plants. However, the TYNDP uses an additional indicator for CO_2 emissions reductions at their societal value. In its decision on the review of the 2019 SDDR, CRE ruled out the use of such a societal value for analysing the benefits of investment projects, since it was possible to rely on the market values of the ETS carbon[57]. Furthermore, the value used in the TYNDP 2024 is €628/t in 2040, whereas the market value is around €150/t at that time.

➢ The results of the TYNDP interconnection needs identification study are not directly comparable with the cost-benefit analyses carried out for the approval of individual investment projects. In particular, the TYNDP's identification of needs is a maximalist assessment of the need for new interconnection capacity, exceeding the capacity identified in the SDDR by 18 GW. It presents various biases:

- project costs are based on feedback from project developers and may be underestimated in light of developments in the DC equipment supply markets ;
- the studies do not take into account the geographical distribution of benefits ;
- internal networks and capacity calculations are not taken into account in the analyses ;
- certain indicators present methodological biases.

➢ It is appropriate to elaborate cost-benefit analyses of interconnection projects on contrasting scenarios for the evolution of energy mixes. The TYNDP scenarios differ from those of RTE, but they can complement the vision of the benefits brought by these projects.

***Question 2020** Do you agree with CRE's analysis of the consistency between the TYNDP and the SDDR?*

[56] For example, at the border with the United Kingdom, the TYNDP 2024 estimates that a new interconnection will contribute around €75 million per year to security of supply in 2040. This figure is significantly higher than the €6 million per year estimated in the TYNDP 2022 for 2030. In addition to the different time horizons, the difference between these two results stems from the methodological choices made in calculating the indicator. CRE raised this issue during its public consultation in March 2024 on the benefits of new interconnections with the United Kingdom. CRE had then set a value of €5 million/year for the benefits associated with security of supply for new interconnection capacity.

[57] *Emissions Trading Schemes*

12. Incentive to carry out priority network projects provided for in TURPE 7 HTB

The TURPE 7 HTB tariff provides for incentive-based regulation relating to the timely completion of priority projects identified in the SDDR. A list of projects and associated milestones (e.g. submission of the technical and economic justification for the project, commencement of work or commissioning) will be defined by CRE once RTE's SDDR has been published and after consultation with market players. These projects will include, in particular, shared infrastructure in dedicated areas.

In light of the review of the SDDR detailed in the previous sections, CRE currently plans to select the projects and milestones defined in the tables below for the implementation of this incentive regulation.

Interconnection projects :

Project milestone	Date of achievement
Completion of studies to assess the impact of internal network reinforcement projects on exchange capacities on the eastern border	31/07/2026
Commercial commissioning of the Celtic project	30/04/2028
Commercial commissioning of the Bay of Biscay project	31/07/2028

Extra-high voltage grid adaptation projects:

Project milestone	Date achieved
Start of work on the project to reinforce the 400 kV Marmagne-Tabarderie 2 line	30/10/2027
Commissioning of the Chaingy-Dambron line	30/10/2028
Completion of studies to identify network reinforcement projects (phase 2 SDDR) in the West Pyrenees area	31/10/2027
Amiens-Petit Caux project: submission of environmental authorisation application	30/04/2027

Shared infrastructure projects in industrial decarbonisation zones[58] :

Project milestone	Date achieved
In the Fos area: commissioning of the Roquerousse substation extension	31/05/2029
In the Le Havre area: commissioning of the Noroit 400 kV substation (last autotransformer)	30/09/2029
In the Dunkirk area: commissioning of the Puythouck substation and associated network upgrades (Flandre Maritime – Puythouck, Grande Synthe – Westhouck and Puythouck – Grande Synthe lines)	30/06/2031

***Question211** Are you in favour of the list of priority projects and associated milestones proposed by CRE? Are there any projects you think should be added to this list?*

***

***Question222** Do you have any other comments regarding the SDDR presented by RTE?*

[58] RTE is still awaiting administrative authorisation for the projects concerned. If necessary, these milestones may be adjusted.

Appendix 1: List of indicators for monitoring RTE's network renewal operations

- number of kilometres of overhead lines replaced or rebuilt;
- number of kilometres of overhead lines created;
- number of kilometres of overhead lines removed;
- number of supports replaced (excluding complete reconstruction of lines);
- number of kilometres of underground lines replaced or rebuilt;
- number of kilometres of underground lines created;
- number of kilometres of underground lines laid;
- number of electrical substations replaced or rebuilt;
- number of substations under mechanical enclosure replaced or rebuilt;
- number of power transformers replaced;
- number of mid-life refurbishments of power transformers;
- number of disconnectors replaced;
- number of circuit breakers replaced;
- number of measuring transformers replaced;
- number of substation control-command sections replaced;
- number of kilometres of fibre optic cable deployed ;
- S3REnR capacity created by the commissioning of new electrical substations.