COMMISSION DE RÉGULATION DE L'ÉNERGIE

DELIBERATION N°2021-12

Deliberation of the French Energy Regulatory Commission of 21 January 2021 deciding on the tariffs for the use of public transmission electricity grids (TURPE 6 HTB)

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

Present: Jean-François CARENCO, Chairman, Christine CHAUVET, Catherine EDWIGE, Ivan FAUCHEUX and Jean-Laurent LASTELLE, commissioners.

Articles L. 341-2 and L. 341-3 and L. 341-4 of the French energy code empower the French Energy Regulatory Commission (CRE) to define the methodology for establishing the tariffs for the use of the public electricity grids for users connected to the high-voltage network (HTB). CRE makes changes to the tariff levels and structure which it deems justified in light of, in particular, an analysis of the operators' accounts, any foreseeable developments in their operating or investment expenses or any changes in grid use. The definition of these tariffs is particularly important during this period of energy transition, in which the grids have a major role to play in a context where the importance of electricity in the energy mix is being strengthened and electricity systems are undergoing profound transformations in Europe.

The current tariff for the use of the public transmission electricity grids, known as TURPE 5 HTB, entered into effect on 1st August 2017, in accordance with the deliberation of 17 November 2016[1], for a period of approximately four years. CRE establishes a new tariff for the use of the public transmission electricity grids, known as TURPE 6 HTB, applicable as of 1 August 2021, for a period of approximately four years.

Given the essential need to provide visibility to market participants and the complexity of the issues to be addressed, CRE ran five public consultations:

- the first, launched on 14 February 2019[2], concerned the regulatory framework applicable to regulated infrastructure operators for the next generation of tariffs. 41 answers were received;
- the second, launched on 23 May 2019[3], mainly covered the principles and challenges of the structure of the TURPE 6 HTB and TURPE 6 HTA-BT tariffs and contained, in particular, the initial guidelines concerning the management component, the metering component, the form of the withdrawal component and the pricing of injection. 37 answers were received;
- the third, launched on 17 October 2019[4], covered the quality of service and actions of grid operators to promote innovation from participants for the electricity sector. 33 answers were received;

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[1] CRE deliberation of 17 November 2016 deciding on the tariffs for the use of public electricity grids in the high-voltage range (HTB): https://www.cre.fr/Documents/Deliberations/Decision/turpe-htb3

[2] Public consultation of 14 February 2019 No.2019-003 relating to the tariff regulatory framework applicable to regulated infrastructure operators in France: https://www.cre.fr/Documents/Consultations-publiques/Cadre-de-regulation-tarifaire-applicable-aux-operateurs-d-infrastructures-regulees-en-France

[3] Public consultation No.2019-011 of 23 May 2019 relating to the structure of the next tariffs, TURPE 6, for the use of the public electricity grids: https://www.cre.fr/Documents/Consultations-publiques/Structure-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-TURPE-6

[4] Public consultation No.2019-019 of 17 October 2019 relating to quality of service and actions of grid operators to promote innovation in participants for the electricity sector: https://www.cre.fr/Documents/Consultations-publiques/qualite-de-service-et-aux-actions-des-gestionnaires-de-reseaux-en-faveur-de-l-innovation-des-acteurs-pour-le-secteur-de-l-electricite

- the fourth, launched on 19 March 2020[5], covered mainly the changes to the withdrawal component envisaged by CRE. 38 answers were received;
- the last, launched on 1 October 2020[6], presented CRE's final proposition for TURPE 6 HTB. It addressed the tariff regulatory framework, particularly the quality of service and innovation, the level of RTE's expenses and revenues and the resulting tariff level as well as the tariff structure. 48 answers were received.

The responses to these five public consultations are published, in their non-confidential version as the case may be, on CRE's website.

In addition, CRE ran a public consultation, launched on 9 July 2020, covering the economic signals sent to electricity producers and the appropriateness of pricing injections, stating however that the changes envisaged were not intended to be implemented with TURPE 6, but possibly afterwards.

In compliance with the law, TURPE 6 HTB is defined so as to cover RTE's costs provided that they correspond to the costs of an efficient grid operator. The present deliberation is based in particular on RTE's tariff proposal, as well as on numerous exchanges with the operator, on internal analyses, external auditors' reports[7] and on feedback from market participants in the different public consultations. CRE also exchanged with RTE and its shareholder CTE.

Moreover, in accordance with the provisions of Article L. 341-3 of the French energy code, CRE took into account the energy policy guidelines forwarded by the minister of ecology and inclusive transition by letter dated 19 June 2020. These guidelines are published on CRE's website[8].

A tariff for the energy transition

In addition to simplicity, foreseeability and continuity objectives, CRE considers that the TURPE 6 HTB tariff must provide answers to the priority issues below:

<u>The public electricity grid plays a major role in the energy transition</u>

The upcoming tariff period (2021-2024) falls within the context of a necessary acceleration of the energy transition, with a massive increase in renewable electricity production. In particular, RTE will be directly concerned by the connection of offshore wind farms and other large-scale renewable energy plants. As an electricity system operator, RTE will also be confronted with the shutdown of coal plants and the major growth in decentralised generation and in electric mobility, which will profoundly modify flows in the electricity transmission system in the years to come: its mission concerning real-time electricity system balancing will change and become more complex.

<u>The necessary investments will have to be made while controlling costs</u>

In its ten-year network development plan (TYNDP), which was examined by CRE in July 2020[9], RTE projects a major increase in its investments: €33 billion over 15 years to which is added €3 billion for real estate, information systems, logistics and light vehicles. These investments are not only related to the energy transition, particularly with regard to offshore wind energy, but also to the progressive ageing of the network, which requires a greater effort for the renewal of infrastructure in order to guarantee a high level of quality and security of supply.

In line with its deliberation examining the TYNDP as an investment strategy, CRE is very attentive to RTE having the means to meet these new requirements. RTE's challenge will be to make the necessary investments while optimising the global cost to operate its network.

<u>Supply quality must remain high</u>

Supply quality is one of the essential missions of the transmission system operator. It is currently at a satisfactory level for RTE's network. Improvements can always be sought, but setting overly ambitious objectives would lead to excessively high costs. For the upcoming four-year period, the main challenge will therefore be to maintain the

[5] Public consultation No.2020-007 of 19 March 2020 relating to the withdrawal component of the next tariffs, TURPE 6, for the use of the public electricity grids: https://www.cre.fr/Documents/Consultations-publiques/composante-de-soutirage-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-turpe-6
[6] Public consultation No.2020-015 of 1 October 2020 relating to the next tariffs for the use of the public electricity transmission grids (TURPE 6 HTB): https://www.cre.fr/Documents/Consultations-publiques/prochain-tarif-d-utilisation-des-reseaux-publics-de-transport-d-electricite-turpe-6-htb
[7] An audit of RTE's operating expenses proposal (excluding purchases related to electricity system operation) for the 2021-2024 period and an audit of the proposal for the remuneration rate of the regulated assets of electricity transmission and distribution system operators.
[8] Minister's letter: https://www.cre.fr/content/download/22581/285281
[9] Deliberation by the French Energy Regulatory Commission of 23 July 2020 examining RTE's ten-year network development plan prepared in 2019: https://www.cre.fr/Documents/Deliberations/Decision/examen-du-schema-decennal-de-developpement-du-reseau-de-transport-de-rte-elabore-en-2019

current performance, even with the major transformations in the electricity mix in France and neighbouring European countries that are set to come.

Technological developments create new flexibility for the networks

Technological developments (smart metering, storage, digital technology, etc.) create a major potential for new sources of flexibility, at a time when the energy transition will generate additional flexibility needs, with the deployment of new infrastructure, particularly in our country, becoming increasingly complex and with the security of supply continuing to be a major issue.

RTE's challenge will therefore be to mobilise new flexibility sources (generation curtailment, storage, load shedding, aggregation of decentralised flexibility) to limit network reinforcement to what is strictly necessary. This approach is in line with the goal of controlling the overall network cost as described in the TYNDP.

RTE must continue to transform and modernise

RTE must transform, modernise and innovate, in connection with its ecosystem, to continue to be a reference operator among the electricity transmission system operators in Europe and in the world.

To do so, TURPE 6 accompanies the operator in this transformation, taking the transformation into account in the definition of operating and investment expense trajectories. This modernisation effort must lead to concrete results, whether it be the implementation of an ambitious research and development programme, particularly in connection with its partners, the effective use of innovative solutions and flexibility sources, the implementation of priority actions within deadlines to promote the innovation of the entire sector or the maintenance of the quality of service. Therefore, TURPE 6 HTB plans to strengthen RTE's incentive regulation for that purpose.

Bill increases must be controlled to ensure acceptability of the tariff

Against the health crisis and possibly an upcoming economic crisis, CRE attaches the highest importance to any tariff increases being justified by unavoidable cost rises and being limited to what is strictly necessary. In particular, the different projected tax decreases will be taken into account.

CRE thus made sure that the modifications to the tariff structure, made necessary by the current context of rapid evolution of the energy system, do not generate any unacceptable bill increases. It is with this in mind that the changes will be smoothed over the four years of the tariff period.

Change in the tariff level

RTE made a tariff proposal outlining its cost projections over the 2021-2024 period, as well as its proposals concerning the regulatory framework.

The integration of the elements in the tariff proposal addressed to CRE by RTE[10] would have led to an increase in the average unit tariff of over 6.25% per year over the entire tariff period.

Changes in expenses to be covered

RTE's proposal is based on three expense items:

- its capital expenses, decrease slightly by -0.5% in 2021 compared to the actual level of 2019, followed by a sustained increase of an average +4.7% between 2021 and 2024. RTE therefore proposes a drop in its rate of return, to 5.35% (compared to 6.125% for the TURPE 5 period) and plans to invest an average €2.2 billion per year during the TURPE 6 period, compared to less than €1.5 billion in 2019. If this programme is executed, RTE's regulated asset base (RAB) as at 31 December 2024 could reach €17.7 billion, up 23% compared to the RAB recorded as at 31 December 2019;
- its purchases related to electricity system operation, increase by +21.7% in 2021 compared to the actual level of 2019, followed by a continuous average increase of +0.7% per year between 2021 and 2024. RTE justifies this development in particular by the increase in energy and capacity prices, reserve volumes and congestion costs because of the growing use of flexibility;
- its operating costs excluding purchases related to electricity system operation, increase by +12.4% in 2021 compared to the actual level of 2019, followed by an average increase of +2.4% per year between 2021 and 2024; RTE attributes this evolution to the implementation of its asset management policy and to the company's necessary adaptation to accompany the increase in investments.

[10] RTE's proposal updated in July 2020, corrected for inflation, withdrawal, injection and subscribed power assumptions and for interconnection revenues assumptions.

To make its decision, in addition to its own analyses, broad consultation of participants and exchanges with RTE, CRE drew on external auditors' assessments, the reports of which are published on CRE's website. These assessments cover the following topics:

- an audit of RTE's proposal concerning its operating expenses (excluding costs related to electricity system operation) and non-grid investments for the 2021-2024 period[11];
- an audit of the proposal concerning the rate of return on electricity distribution and transmission system operators' regulated assets[12].

Following its analyses, feedback from contributors to the public consultation of 1 October 2020 and additional exchanges it had with RTE, CRE decided to limit the increase in expenses compared to that proposed by RTE while maintaining an appropriate return on investments made. TURPE 6 HTB guarantees RTE's capacity to lead an ambitious and investment programme to accompany the energy transition and modernise the existing network, and to achieve its digital transformation. The goal is thus to enable RTE to, on the one hand, meet participants' new needs and to be an actor in the energy transition, and on the other hand, to maintain a high supply quality level.

Operating expenses

For RTE, CRE adopted an ambitious operating expenses trajectory during the TURPE 6 period, taking into account, in particular:

- a 13% increase in purchases related to electricity system operation compared to the actual figure for 2019, due in particular to the increase in market prices influencing the cost of loss compensation in the public transmission system;
- a 15% increase in asset management expenditure compared to the actual figure for 2019, based on RTE's proposals in terms of operation volumes, to enable it to fulfil its policy. This increase however takes into account a more measured increase in the unit costs of these operations when the operator's proposal was not sufficiently justified;
- an 8% increase in the operating expenses related to information systems (IS) compared to the actual figure for 2019, so that RTE could pursue its effort to improve its management tools, strengthen the cybersecurity of its installations and best meet the needs of system users and market participants, while taking into account the cost reductions made possible by certain IS investments made or in progress;
- an 11% increase in staff expenses compared to the actual figure for 2019, to enable RTE to implement its asset management policy and accompany the major growth in investments, particularly for the connection of offshore wind farms.

TURPE 6 HTB allows customers to benefit from the drop in the tax on electricity generation, in the amount of €70 million/year (0.8% of RTE's costs).

The trajectory of net operating expenses set by CRE corresponds to an overall envelope. RTE is free to distribute this envelope among the different types of expenses as it chooses.

Capital expenses

With regard to investments, CRE adopted:

- for network investments, the investment trajectory proposed by RTE, built in line with the TYNDP, where only the investments rejected by CRE have not been included;
- for IS investments, a 5% increase compared to the actual figure for 2019, however taking into account RTE's possibility of prioritising the development of certain projects so as to limit the increase, and therefore the costs for users;
- for real estate investments, an increase in investments, subject to the approval of the construction projects for the regional headquarters of Lille and Marseille.

Network investments are covered by the tariff (excluding subsidies or third-party contributions) depending on projects completed, which are fully taken into account in the expenses and revenues clawback account (CRCP). "Non-grid" investments, including IS, real estate and light vehicles, are given an incentive-based capital expenses trajectory.

[11] Audit of RTE's proposal concerning its operating expenses (excluding costs related to electricity system operation) and non-grid investments for the 2021-2024 period: https://www.cre.fr/content/download/22899/288698
[12] Audit of the proposal concerning the remuneration rate of electricity distribution and transmission system operators' regulated assets: https://www.cre.fr/content/download/22887/288575

Given the elements of analysis at its disposal and market observations, CRE adopts a drop in the weighted average cost of capital (WACC) which stands at 4.6% (nominal, before tax).

The level of these parameters, for which the methodology for determining the value remains unchanged compared to TURPE 5 HTB, reflects:

- the drop in financing costs against a significant and sustainable drop in interest rates in the markets;
- the planned decrease in corporate tax, which shall go from an average 34.43% in TURPE 5 HTB to an average 26.47% over the TURPE 6 period.

This method is based on a standard-structure WACC and guarantees a reasonable return on capital invested, maintaining the attractiveness of energy infrastructure in France compared to other European countries.

Interconnection revenues

CRE adopts RTE's interconnection revenue assumptions, which are deducted from TURPE 6 HTB in the amount of an average €366 million/year. This trajectory corresponds to a 19% drop in interconnection revenue compared to the actual figure for 2019. The corresponding revenue is included fully in the CRCP.

Change in withdrawals and subscribed power, as well as injections

The change in the tariff depends not only on the level of expenses to be covered, but also on the volume effect related to the evolution of withdrawals and subscribed power, as well as HTB 2 and 3 injections, on the basis of which tariffs are established so as to recover the projected tariff revenue.

Within the framework of its tariff proposal, RTE had submitted assumptions to CRE taking into account a portion of the effects of the COVID-19 crisis identified at the time. The withdrawal and subscribed power projections have, since then, been updated by RTE, in coordination with Enedis, in order to take into account the impact of this crisis and the most recent available data.

Between the actual figure for 2019 and the 2021-2024 period, RTE projects:

- a drop (-3.8%) in energy withdrawals (compared to -2.1% in its previous estimates), which, apart from the effect related to the COVID-19 crisis, is due in particular to the improvement in energy efficiency and the development of decentralised generation, part of which is consumed in the distribution network and therefore reduces withdrawals from the transmission network;
- a slight drop (-0.8%) in subscribed power (compared to -0.6% in its previous estimates) because of the stable withdrawal peak;
- a drop (-2.0%) in injections by centralised generation connected to the HTB 2 and HTB 3 networks, due to the closure of coal plants and the Fessenheim nuclear plant, as well as to the development of decentralised generation, which is gradually replacing centralised generation;
- a major growth (+30.5%) in distribution backfeed to transmission (including the HTB2 network) and in generation connected to HTB 1 networks, which is due to the development of renewable energy production.

In addition, in compliance with Article L.341-4-2 of the energy code, certain categories of customers can have a reduction in their electricity bill. The lower revenue associated with the implementation of this system intended for electricity-intensive customers is taken into account by CRE to set TURPE 6 HTB.

Change in the tariff level

The change in TURPE 6 HTB is the result, apart from the increase in expenses to be covered and the expected drop in withdrawals, injections and subscribed power, of the reconciliation of the CRCP from the previous tariff period. The CRCP stands at an average €1.5 million/year, compared to €29 million/year during TURPE 5. This forecast CRCP balance is due to two opposing effects: on the one hand, the COVID-19 crisis affected consumption volumes and therefore the tariff revenue in 2020; on the other hand, RTE received additional revenue from the sale of interconnection capacity in the capacity mechanism during the last auction held in 2020.

The average increase, for all customers, in TURPE 6 HTB is +1.09% as at 1 August 2021 and an average +1.57% per year over the tariff period, based on an average inflation assumption over the period of 1.07% per year.

In a context marked by a major increase in investments to meet the challenges of the energy transition, the TURPE update however remains moderate. This moderation is made possible in particular by the financial environment favourable to investments in the energy transition and the inclusion of major tax drops planned in the draft finance law for 2021.

Incentive regulation

The assessment of the previous tariff periods and feedback from public consultations showed that the incentive regulation framework works well and only requires periodic improvements. Therefore, for TURPE 6 HTB, CRE is maintaining the main incentive regulation mechanisms in effect, adjusting them when necessary: incentive regulation for the control of operating and investment expenses, incentive regulation for supply quality and for research and development, *ex facto* coverage of certain differences through the CRCP account.

In a context marked by a sharp increase in RTE's investments, CRE introduces a mechanism aiming at providing RTE with the incentive to prioritise its network investment expenses. This mechanism determines a multi-annual envelope which constitutes a cap beyond which the investment costs incurred would result in a penalty.

In addition, when examining RTE's TYNDP, CRE was in favour of the asset management policy proposed by RTE aiming at extending the lifetime of assets so as to limit investment expenses. This policy results in a significant increase in the operator's operating expenses. In this context, CRE adopts, for the preparation of the trajectories of expenses to be covered, the volume of operations proposed by RTE. In return, TURPE 6 HTB provides for an *ad hoc* mechanism to ensure compliance with the execution of the work volumes and activities having served to build the tariff trajectory, and to return to network users, through the CRCP, the projected cost of operations not completed at the end of the tariff period.

With regard to purchases related to electricity system operation, CRE:

- maintains the incentive regulation for expenses related to loss compensation, but strengthens it by increasing the incentive rate concerning the volume of losses from 10% to 20%, in line with the incentive level applicable to other regulated infrastructure operators in France;
- updates the incentive level concerning balancing reserves: while TURPE 5 HTB gave incentive to RTE to control the volume of its balancing reserves, the new mechanism adopted by CRE aims to incentivise RTE for all costs of procuring these reserves;
- harmonises the incentive relating to national and international congestion costs by applying a 20% incentive rate to all costs to adapt it to the optimal network sizing policy and European challenges.

Lastly, CRE strengthens the monitoring mechanism and the incentive regulation mechanism for quality of service, by introducing, in particular, incentive regulation for innovation, covering mainly the quality of data transmitted by RTE to market participants and RTE's role in facilitating external innovation, within the framework of its public service missions. CRE has thus identified priority actions and introduced an incentive for RTE to execute them within the necessary deadlines to enable market participants and network users to innovate.

Tariff structure

CRE builds the tariffs by complying with several fundamental principles:

- "Stamp" pricing: pricing of network access is independent of the distance between the injection site and the withdrawal site;
- Standardised tariff: the same tariffs for network use apply across the whole national territory;
- Non-discrimination / cost reflection: pricing must reflect the costs generated by each user category independently of their final use of the electricity;
- Time and season variations.

Within this framework, CRE considers that in order to best meet the expectations of the different stakeholders, the tariffs for the use of the grids must reconcile the following objectives: efficiency, readability and acceptability.

The energy and digital transition and the change in uses strengthen the need to send grid users relevant tariff signals concerning network use and investments, whether they pertain to equipment (such as electric vehicles), insulation and energy efficiency expenses, or storage and decentralised generation, potentially self-consumed.

Therefore, CRE has significantly updated the tariff structure, taking advantage in particular of the new data provided by the network operators and following a broad consultation of market participants. The developments aim to convey price signals best reflecting the costs generated for the community by the use of networks in compliance with the principle of standardised tariff. The form of the tariffs must therefore be robust and adapted to the evolution of uses associated with the current context of energy and digital transition. In that regard, the introduction of pricing based on long-term marginal network costs aimed at better reflecting the concentration of costs generated by uses during winter as well as the access cost meets this challenge.

The tariff were prepared by drawing on the more refined data transmitted by system operators on the structure of their costs and the functioning of their networks, as well as the analysis of the load curves transmitted directly by network users in response to the public consultation of 1 October 2020. For transparency purposes, CRE will publish the data and the models used to perform structure work.

CRE made sure that the changes introduced for the TURPE 6 period do not lead to overly high increases in terms of billing for network users. To do so, it implemented, in particular, a smoothing over four years of the different developments, which will give all participants the time necessary to adapt their behaviour to the change in tariff signals.

The present deliberation will be published on CRE's website and forwarded to the minister of the ecological transition as well as the minister of the economy, finance, and the recovery.

The present deliberation will be published in the *Journal officiel* of the French Republic.

The Conseil supérieur de l'énergie, consulted by CRE on the draft decision, delivered its opinion on 12 January 2021.

Paris, 21 January 2021

For the Energy Regulatory Commission,

The Chairman,

Jean-François CARENCO

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1. CRE'S POWERS AND THE TARIFF PREPARATION PROCESS

1.1 CRE's powers

Articles L. 341-2 to L. 341-4 of the French energy code define CRE's powers regarding the pricing of the use of public electricity transmission and distribution grids. Article L. 341-3 states that "*the methodologies used to establish the tariffs for the use of the public electricity transmission and distribution grids are set by the French Energy Regulatory Commission*".

Article L. 341-2 of the same code sets out, in particular, that "*the tariffs for the use of the public transmission network and the public distribution grids shall be calculated in a transparent and non-discriminatory manner, so as to cover all the costs borne by the operators of these networks provided that these costs correspond to those of an efficient network operator*".

Article L. 341-3 of the same code specifies that CRE "*can propose a multi-annual tariff framework together with appropriate short- or long-term incentives to encourage transmission and distribution grid operators to improve their performance particularly as regards the quality of the electricity, to encourage the integration of the domestic electricity market and security of supply and to find ways to improve productivity*". This article also states that CRE "*consults energy market participants as it sees fit*". In addition, this article provides that CRE "*takes into account the energy policy guidelines indicated by the administrative authority*".

Moreover, Article L. 341-4 of the same code states that "*the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which consumption of clients on a whole is at its highest at the national level*". *They can also encourage their clients to limit their consumption during local peak periods. In that regard, the structure and level of tariffs for the use of the transmission and distribution grids can, provided that all of the costs are covered in compliance with Article L.341-2, and in proportion to the goal to control electricity peaks, deviate for a customer from the strict coverage of the network costs it generates."*

Lastly, Article L.134-1 of the energy code provides for CRE to specify the rules concerning "*the missions of public electricity transmission and distribution grid operators in terms of network operation and development*", as well as those relating to the "*conditions for accessing and using the grids, including the methodology for calculating the tariffs for the use of the grids and the developments in these tariffs [...]*".

CRE's present deliberation defines the method for establishing the tariff for the use of the electricity transmission grids, and sets the "TURPE 6 HTB" tariff as from 1 August 2021 for roughly four years.

1.2 Tariff preparation process

1.2.1 Consultation of stakeholders

To establish TURPE 6 HTB, given the need for visibility and the complexity of issues, CRE drew on, in addition to its own analyses and assessments by external consultants, the results of five public consultations:

- the first, launched on 14 February 2019[13], concerned the regulatory framework applicable to regulated infrastructure operators for the next generation of tariffs. 41 answers were received;
- the second, launched on 23 May 2019[14], mainly covered the principles and challenges of the structure of the TURPE 6 HTB and TURPE HTA-BT tariffs and contained, in particular, the initial guidelines concerning the management component, the metering component, the form of withdrawal pricing and the pricing of injection. 37 answers were received;
- the third, launched on 17 October 2019[15], covered the quality of service and actions of grid operators to promote innovation from participants for the electricity sector. 33 answers were received;

[13] Public consultation of 14 February 2019 No.2019-003 relating to the tariff regulatory framework applicable to regulated infrastructure operators in France: https://www.cre.fr/Documents/Consultations-publiques/Cadre-de-regulation-tarifaire-applicable-aux-operateurs-d-infrastructures-regulees-en-France
[14] Public consultation No.2019-011 of 23 May 2019 relating to the structure of the next tariffs, TURPE 6, for the use of the public electricity grids: https://www.cre.fr/Documents/Consultations-publiques/Structure-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-TURPE-6
[15] Public consultation No.2019-019 of 17 October 2019 relating to quality of service and actions of grid operators to promote innovation in participants for the electricity sector: https://www.cre.fr/Documents/Consultations-publiques/qualite-de-service-et-aux-actions-des-gestionnaires-de-reseaux-en-faveur-de-l-innovation-des-acteurs-pour-le-secteur-de-l-electricite

- the fourth, launched on 19 March 2020[16], covered mainly the changes to the withdrawal component envisaged by CRE. 38 answers were received.
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The responses to these five public consultations are published, in their non-confidential version as the case may be, on CRE's website.

In addition, CRE published a public consultation, launched on 9 July 2020[18], covering the economic signals sent to electricity producers and the appropriateness of pricing injections, stating however that the changes envisaged were not intended to be implemented with TURPE 6, but possibly afterwards.

Lastly, CRE exchanged with CRE before and after the public consultation of 1 October 2020, as well as with its shareholder CTE.

1.2.2 Energy policy guidelines

In accordance with the provisions of Article L. 341-3 of the French energy code, CRE takes into account the energy policy guidelines forwarded by the minister of ecology and inclusive transition by letter dated 19 June 2020. These guidelines address, in particular:

- the importance of ensuring that the tariffs for the use of the public electricity grids are in line with the general ambitions of the government in terms of climate protection and biodiversity;
- the need to incentivise the operator to control its costs in order to limit the impact of the tariffs for the use of the grids on users' bills;
- the maintenance of a high quality of electricity supplied, reflected in the sufficient renewal of existing infrastructure and specific attention to network resilience to meteorological and climate variations;
- the incentive that must be given for making the investments necessary for the energy transition, particularly the connection of renewable energy, cost-effectively and within deadlines compatible with energy policy needs;
- the need to encourage the system operator to implement solutions to bring flexibility to the electricity system, however without preventing the investments necessary for the energy transition;
- the contribution of the tariffs to the reduction of consumption during peak periods;
- the necessary balance between the fixed and variable portions of the tariffs given the effects of the tariff structure on policies to control consumption and combat fuel poverty.

The letter of 19 June 2020 is published on CRE's website[19].

1.2.3 Transparency

CRE endeavours to ensure the greatest level of transparency in the grid tariff preparation work for all stakeholders.

In that regard, it has published all the external assessments used in the tariff preparation process on its website. These assessments cover the following topics:

- an audit of RTE's proposal concerning its operating expenses (excluding costs related to electricity system operation) for the 2021-2024 period[20];
- an audit of RTE's return on capital proposal[21] .

[16] Public consultation No.2020-007 of 19 March 2020 relating to the withdrawal component of the next tariffs for the use of the public electricity grid, TURPE 6: https://www.cre.fr/Documents/Consultations-publiques/composante-de-soutirage-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-turpe-6;
[17] Public consultation No.2020-015 of 1 October 2020 relating to the next tariffs for the use of the public electricity transmission grids (TURPE 6 HTB): https://www.cre.fr/Documents/Consultations-publiques/prochain-tarif-d-utilisation-des-reseaux-publics-de-transport-d-electricite-turpe-6-htb
[18] Public consultation No.2020-011 of 9 July 2020 relating to the economic signals sent to electricity producers: https://www.cre.fr/Documents/Consultations-publiques/consultation-publique-relative-aux-signaux-economiques-envoyes-aux-producteurs-d-electricite
[19] Minister's letter: https://www.cre.fr/content/download/22581/285281
[20] Document published within the framework of the public consultation of 1 October 2020
[21] Document published within the framework of the public consultation of 1 October 2020

In addition, after publishing the data and tools used to elaborate the structure of TURPE 5 HTB, CRE intends to broaden the data and tools made available to participants to enable them to better adopt the evolutions in the tariff structure introduced in the present deliberation.

Compared to TURPE 5 HTB, CRE had access to more refined data from the system operators, particularly concerning the grid topology, the grid costs and their model as well as energy flows (actual flows for each HTB and HTA (medium-voltage) user and based on the model of a representative 1,000 pockets for the low-voltage range (BT)). CRE used this data to improve its tariff model and underpin its structure development proposals, particularly with regard to the withdrawal component. To illustrate the method used, in Q3 2021 CRE will publish the different modelling carried out at each calculation stage, and all of the data used, with the exception of commercially sensitive information which will be anonymised.

1.3 Challenges for the TURPE 6 period

In addition to foreseeability and continuity objectives, CRE considers that the TURPE 6 HTB tariff must provide answers to the priority issues below:

The public electricity grid plays a major role in the energy transition

The upcoming tariff period (2021-2024) falls within the context of a necessary acceleration of the energy transition, with a massive increase in renewable electricity production. In particular, RTE will be directly concerned by the connection of offshore wind farms and other large-scale renewable energy plants. As an electricity system operator, RTE will also be confronted with the shutdown of coal plants and the major growth in decentralised generation and in electric mobility, which will profoundly modify flows in the electricity transmission system in the years to come: its mission concerning real-time electricity system balancing will change and become more complex.

The necessary investments will have to be made while controlling costs

In its ten-year network development plan (TYNDP), which was examined by CRE in July 2020[22], RTE projects a major increase in its investments: €33 billion over 15 years to which is added €3 billion for real estate, information systems, logistics and light vehicles. These investments are not only related to the energy transition, particularly with regard to offshore wind energy, but also to the progressive ageing of the network, which requires a greater effort for the renewal of infrastructure in order to guarantee a high level of quality and security of supply.

In line with its deliberation examining the TYNDP as an investment strategy, CRE is very attentive to RTE having the means to meet these new requirements. RTE's challenge will be to make the necessary investments while optimising the global cost to operate its network.

Supply quality must remain high

Supply quality is one of the essential missions of the transmission system operator. It is currently at a satisfactory level for RTE's network. Improvements can always be sought, but setting overly ambitious objectives would lead to excessively high costs. For the upcoming four-year period, the main challenge will therefore be to maintain the current performance, even with the major transformations in the electricity mix in France and neighbouring European countries that are set to come.

Technological developments create new flexibility for the networks

Technological developments (smart metering, storage, digital technology, *etc.*) create a major potential for new sources of flexibility, at a time when the energy transition will generate additional flexibility needs, with the deployment of new infrastructure, particularly in our country, becoming increasingly complex and with the security of supply continuing to be a major issue.

RTE's challenge will therefore be to mobilise new flexibility sources (generation curtailment, storage, load shedding, aggregation of decentralised flexibility) to limit network reinforcement to what is strictly necessary. This approach is in line with the goal of controlling the overall network cost as described in the TYNDP.

RTE must continue to transform and modernise

RTE must transform, modernise and innovate, in connection with its ecosystem, to continue to be a reference operator among the electricity transmission system operators in Europe and in the world.

To do so, TURPE 6 HTB accompanies the operator in this transformation, taking the transformation into account in the definition of operating and investment expense trajectories. This modernisation effort must lead to concrete

[22] Deliberation by the French Energy Regulatory Commission of 23 July 2020 examining RTE's ten-year network development plan prepared in 2019: https://www.cre.fr/Documents/Deliberations/Decision/examen-du-schema-decennal-de-developpement-du-reseau-de-transport-de-rte-elabore-en-2019

results, whether it be the implementation of an ambitious research and development programme, particularly in connection with its partners, the effective use of innovative solutions and flexibility sources, the implementation of priority actions within deadlines to promote the innovation of the entire sector or the maintenance of the quality of service. Therefore, TURPE 6 HTB plans to strengthen RTE's incentive regulation for that purpose.

Bill increases must be controlled to ensure acceptability of the tariff

Against the health crisis and possibly an upcoming economic crisis, CRE attaches the highest importance to any tariff increases being justified by unavoidable cost rises and being limited to what is strictly necessary. In particular, the different projected tax decreases will be taken into account.

CRE thus made sure that the modifications to the tariff structure, made necessary by the current context of rapid evolution of the energy system, do not generate any unacceptable bill increases. It is with this in mind that the changes will be smoothed over the four years of the tariff period.

2. TARIFF REGULATORY FRAMEWORK

2.1 Main tariff principles

The preparation of TURPE 6 HTB is based on the definition, for the upcoming tariff period, of RTE's allowed revenue and a forecast trajectory of energy withdrawals and injections as well as power subscribed by users connected to RTE's network.

The TURPE 6 HTB tariff also defines a regulatory framework aimed, on the one hand, at limiting RTE's and/or users' financial risk for certain predefined expense or revenue items, through an expenses and revenues clawback account (CRCP), and on the other hand, at encouraging RTE to control its expenses and improve the quality of service provided to its users through incentive mechanisms.

All of these elements are used to establish the tariff applicable as at 1 August 2021, and the modalities for their yearly update.

2.1.1 Determination of allowed revenue

In the present deliberation, CRE defines the projected allowed revenue of RTE for the 2021-2024 period based on the tariff proposal forwarded by RTE and on its own analyses. In accordance with Article L. 341-2 of the energy code, the allowed revenue covers RTE's costs provided that they correspond to those of an efficient operator.

This projected allowed revenue is composed of net operating expenses (net OPEX) and normative capital expenses (CCN), minus interconnection revenue (IR)[23], and reconciliation of the CRCP balance:

$$AR = \text{net OPEX} + CCN - IR + CRCP$$

Where:

- AR: projected allowed revenue for the period;
- net OPEX: target net operating expenses for the period;
- CCN: target normative capital expenses for the period;
- IR: projected interconnection revenue for the period;
- CRCP: reconciliation of the CRCP balance estimated at the end of TURPE 5 HTB.

The tariff framework guarantees collection of the allowed revenue.

[23] Interconnection revenues include the revenues resulting from interconnection capacity allocation and revenues resulting from capacity mechanisms.

2.1.1.1 Net operating expenses

RTE's net OPEX comprise the purchases related to electricity system operation and net OPEX excluding purchases related to electricity system operation.

Purchases related to electricity system operation include, in particular, the costs for compensating losses in the transmission network, the costs for constituting and re-constituting balancing reserves, the costs related to voltage ancillary services, congestion costs and costs related to the interruptibility mechanism.

The net OPEX excluding purchases related to electricity system operation include gross operating expenses (mainly comprising staff expenses, external procurement, and taxes) minus non-tariff related revenue (mainly comprising capitalised production and revenue from ancillary services).

2.1.1.2 Normative capital expenses

Normative capital expenses (CCN) are composed of the return on capital and the depreciation of fixed assets. These two components are calculated from the valuation and evolution of assets exploited by RTE - the regulatory asset base (RAB) - and assets under construction (AuC - i.e. investments made for assets that have not yet been commissioned). The RAB is determined based on the net value of fixed assets, net of subsidies and contributions received from third parties.

CCN equates to the sum of the depreciation of assets in the RAB and the return on capital. This corresponds to the product of the value of the RAB and the weighted average cost of capital (WACC) plus the product of the value of the AuC and the cost of debt.

CCN = Annual depreciation of the RAB + RAB x WACC + AuC x cost of debt

2.1.2 Return on capital and coverage of investments

2.1.2.1 Method for the calculation of the rate of return

For the TURPE 6 tariff period, CRE is readopting the method used to set the rate of return on capital in effect in the TURPE 5 HTB tariff, which is based on a WACC with a normative financial structure. RTE's rate of return on capital must indeed enable it to, on the one hand, service the interest on its debt, and on the other hand, provide its shareholders with a return on equity comparable to what they could obtain for investments elsewhere entailing a comparable level of risk. This cost of equity is estimated based on the capital asset pricing model (CAPM).

In addition, CRE commissioned an external consultant to assess the financial parameters for calculating the capital expenses of public electricity system operators and to analyse RTE's proposal concerning the calculation of capital expenses. The non-confidential version of this assessment was published on CRE's website within the framework of the public consultation of 1 October 2020.

2.1.2.2 Method for calculating the regulated asset base

For the TURPE 6 period, CRE re-adopts the return on capital terms in effect in TURPE 5 HTB.

The value of the RAB is thus calculated based on the net book value of assets in service[24], minus investment subsidies received[25], contributions received from third parties and revenue collected in advance from Artéria, RTE's subsidiary, according to the principles outlined in CRE's communication of 7 December 2006 relating to the audit of Artéria's fibre optic development activities and promotion of its pylons for the 2005 fiscal year[26].

The agreed date for incorporating assets into the RAB is set at 1 January of the year following their commissioning. The RAB grows with investments commissioned and shrinks with asset outflows and asset depreciation covered by the tariffs.

2.1.2.3 Return on capital for assets under construction

In TURPE 5 HTB, assets under construction are remunerated normatively at the nominal cost of debt applicable during the tariff period.

[24] Fixed assets benefiting from the legal revaluation of 1976 are incorporated in the RAB at their acquisition cost (excluding revaluation).
[25] Investment subsidies are aids granted to the company to acquire or create fixed assets for its future activity.
[26] http://www.cre.fr/documents/deliberations/communication/audit-des-activites-de-developpement-du-reseau-de-fibres-optiques-et-de-valorisation-des-points-hauts-d-rteria-filiale-de-rte-pour-l-exercice-2005/consulter-la-communication

Since most of RTE's AuC corresponds to long-term investments (maturity over a year), CRE stated in its public consultation of 1 October 2020 that it intended to maintain remuneration of all AuC at the cost of debt.

The suppliers and customers that took part in the public consultation are mostly in favour of the remuneration of AuC at a rate lower than the WACC, in order to encourage the commissioning of assets at the earliest possible date. The majority of infrastructure operators, including RTE, are against remuneration at the cost of debt, and request remuneration at the same rate as that of assets put into service.

For TURPE 6 HTB, CRE decides to maintain remuneration of AuC at the cost of debt, which it considers to be an effective incentive for the rapid commissioning of operators' investment projects.

2.1.2.4 Treatment of assets removed from inventory (stranded costs, asset disposals)

2.1.2.4.1 Treatment of stranded costs

Within the framework of the public consultations of 1 and 8 October 2020 relating to TURPE 6 HTB and HTA-BT, CRE proposed extending to all regulated infrastructure tariffs the principles of stranded cost coverage in effect in the ATRT7[27] and ATRD6[28] tariffs. These are based in particular on an incentive to control recurring or foreseeable stranded costs through a tariff trajectory on the basis of an annual envelope and a case-by-case analysis of the other types of stranded costs.

Most suppliers and industrial participants were in favour of the principles of stranded cost coverage envisaged. Several infrastructure operators and their shareholders however are opposed to the establishment of an incentive-based trajectory for outflows of assets before the end of their useful life. They request coverage through the CRCP, because of the uncontrollable nature of some of these stranded costs corresponding most often to installation changes at the request of third parties, or destruction of installations particularly because of climate hazards.

CRE nevertheless considers that these expenses are foreseeable, in part (average volume of infrastructure destroyed following hazards and average volume of third-party requests for installation modifications), and partly controllable. Moreover, with RTE's investment and maintenance decisions, particularly its network undergrounding policy, leading to an increasing portion of its infrastructure not being affected by climate hazards, it can limit the volume of fixed assets demolished in the event of climate hazards.

Given all of these elements, and in line with the mechanism adopted by CRE in the ATRT7 and ATRD6 tariffs, CRE adopts, for the TURPE 6 period, the following treatment of stranded costs:

- recurring or foreseeable stranded costs ("costs of studies and of work not followed through" and "net book value of demolished fixed assets) are given an incentive-based trajectory;
- the cost of studies not followed through relating to large projects previously and explicitly approved by CRE are covered by the tariff through the CRCP;
- coverage of other stranded costs will be examined by CRE on a case-by-case basis, based on substantiated proposals submitted by RTE.

The costs to be covered, where applicable, by the tariffs, are taken into account at their book value minus any sales proceeds.

2.1.2.4.2 Treatment of disposed assets

When an asset is disposed of by an operator, it exits the RAB and therefore ceases to generate capital expenses (depreciation and remuneration). This disposal may generate a profit for the operator, equal to the difference between the proceeds from the disposal and the book value of the asset.

In particular, real estate assets, which are included in the RAB, depreciated and remunerated during the entire time that they are in the operators' asset portfolio, are likely, on the day they are disposed of, to generate a profit, which is sometimes considerable.

In its public consultation of 1 October 2020, CRE questioned stakeholders about the treatment to be applied to disposed assets. Most participants are in favour of CRE's proposal to take into account part of the gains made by the operator in the tariff, considering that grid users participated in the funding of the disposed assets.

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[27] Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the tariffs for the use of GRTgaz's and Teréga's natural gas transmission networks: https://www.cre.fr/Documents/Deliberations/Decision/tarif-d-utilisation-des-reseaux-de-transport-de-gaz-naturel-de-grtgaz-et-terega

[28] Deliberation by the French Energy Regulatory Commission of 23 January 2020 deciding on the equalised tariff for the use of GRDF's public natural gas distribution networks: https://www.cre.fr/Documents/Deliberations/Decision/tarif-pereque-d-utilisation-des-reseaux-publics-de-distribution-de-gaz-naturel-de-grdf

In line with the mechanism adopted by CRE in the ATRT7 and ATRD6 tariffs, CRE adopts, for the TURPE 6 period, the following treatment of real estate or land disposals:

- if the disposal gives rise to an accounting gain, 80% of the disposal proceeds net of the sold asset's net book value are included in the CRCP so that network users can benefit from the greater part of the gains made from the sale of these assets, while maintaining an incentive for RTE to maximise this gain. RTE therefore keeps 20% of the profit;
- a disposal giving rise to an accounting loss will be examined by CRE, based on a detailed dossier submitted by RTE.

2.1.3 Principle of the CRCP

The level of the TURPE 6 HTB tariff is defined by CRE based on assumptions about the forecast level of RTE's revenues and expenses. An *ex post* adjustment mechanism, the expenses and revenues clawback account (CRCP), was introduced in order to take into account all or a portion of the differences between actual expenses and revenues and forecast expenses and revenues for predefined items (see section 2.3.3). The CRCP is also used for the payment of financial incentives (bonuses or penalties) resulting from the application of incentive regulation mechanisms.

The CRCP balance is calculated as at 1 January of each year. It is reconciled over a period of one year, from 1 August of year *N* to 31 July of year *N*+1 within the limit of an annual tariff update associated with this reconciliation of +/-2%. If this limit is reached, the CRCP balance not reconciled during the year in question is carried over to the following year.

In order to ensure financial neutrality of this system, an interest rate equal to the risk-free rate taken into account in the calculation of the WACC applies to the CRCP balance (i.e. 1.70% for the TURPE 6 period).

In addition, the forecast CRCP balance at the end of the tariff period is taken into account to establish the allowed revenue of the following period and is reconciled over four years. The forecast CRCP balance is therefore reset to zero at the start of each tariff period.

Most contributors to the public consultations of 14 February 2019 and 1 October 2020 were in favour of re-adopting the operating principles of the CRCP under the same conditions as those prevailing during the TURPE 5 period.

CRE decides to maintain the operating principle of the CRCP while updating the scope of expenses and revenues taken into account by this mechanism (see section 2.3.3).

2.2 Tariff calendar

2.2.1 A tariff period of roughly four years

TURPE 6 HTB will apply for a period of approximately four years, as from 1 August 2021. It aims to cover the expenses of the calendar years from 2021 to 2024. It will be updated annually, as at 1 August of each year, based on the terms described in section 2.2.2 of the present deliberation.

In their responses to the consultation of 14 February 2019 relating to the tariff regulatory framework, market participants were in favour of maintaining this duration of four years, considering, like CRE, that it provides the market with visibility into the development of infrastructure tariffs and that it allows operators the time needed for undertaking productivity efforts.

In addition, TURPE 6 HTB provides for a *rendez-vous* clause, as was the case in the previous tariff, which can be activated by RTE. Therefore, any consequences of new legal or regulatory provisions or a jurisdictional or quasi-jurisdictional decision may lead to a re-examination of the tariff trajectory for the last two years of the tariff period (2023 and 2024) if the level of net operating expenses adopted for the preparation of TURPE 6 HTB changes by at least 1%.

2.2.2 Principles of the annual tariff update

Within the framework of TURPE 5 HTB, CRE had decided that, excluding the effects related to the reconciliation of the CRCP, the electricity transmission tariff would change by 6.76% as at 1 August 2017, then according to inflation as at 1 August 2018, 2019 and 2020. In its public consultation of 1 October 2020, CRE stated its intention to smooth the change in TURPE HTB over four years, given the need to ensure the acceptability of the tariff increases envisaged. Participants contributing to this public consultation are mainly in favour of this approach.

Therefore, TURPE 6 HTB will be updated annually, as at 1 August of each year, according to the following principles:

a) Tariff levels, excluding the annual injection component, will be adjusted as at 1 August of each year *N* for the following percentage change, compared to the tariff level in effect as at 31 July of year *N*:

$$Z = CPI + X + K$$

Where:

- Z is the variation in the tariffs as at 1 August of year *N* expressed as a percentage and rounded off to the nearest 0.01%;
- CPI is, for an adjustment of the tariffs as at 1 August of year *N*, the forecast inflation rate for year *N* taken into account in the finance law of year *N*;
- X is the annual change factor for the tariffs defined by CRE in the present deliberation, equal to 0.49% (see section 3.4);
- K is the change in the tariffs, expressed as a percentage, resulting in particular from the reconciliation of the CRCP balance. K lies between +2% and -2%;

b) the forecast reference used to calculate the CRCP for the following year will be updated each year with regard to the costs for constituting and re-constituting the balancing reserves.

In addition, CRE may take into account, during annual updates of TURPE 6 HTB, changes in the incentive regulation of RTE's quality of service and continuity of supply (addition, modification or elimination of indicators, objectives or financial incentives).

2.2.3 Calculation of the CRCP balance as at 1 January of year *N*

The overall CRCP balance is calculated before the definitive closure of RTE's annual accounts. It is equal to the amount to be paid into or deducted from the CRCP for the year passed (year *N-1*), to which is added the balance of the CRCP not reconciled over previous years.

The amount to be paid into or deducted from the CRCP is calculated by CRE, as at 31 December of each year, based on the difference between the actual figure, for each item concerned, and the reference amounts defined in Annex 1. All or part of the difference is paid into the CRCP, the share being determined based on the coverage rate specified by the present deliberation.

The expenses and revenue items fully or partially covered through the CRCP for the TURPE 6 period are defined in section 2.3.3 of the present deliberation. The accounting data presented by RTE will be used as a basis for the expenses and revenues taken into account through the CRCP, when possible. Where appropriate, inclusion of the different items through the CRCP will be combined with effective and careful inspection of the costs incurred. Such inspections may, in particular, focus on the investments undertaken by RTE and on the expenses relating to the compensation of electricity losses, balancing services and various differences. The consequences of the audits conducted by CRE for TURPE 6 HTB will be taken into account through the CRCP. Any bonuses or penalties related to the incentive regulation mechanism will also be taken into account through the CRCP.

The projected CRCP balance as at 1 January 2021 is used to define the target revenues of TURPE 6 HTB, and will be reconciled over the four-year tariff period. The difference between the definitive balance of the CRCP (which will be determined after the closure of RTE's 2020 accounts) and the forecast balance taken into account in the present deliberation will be reconciled through the tariff update as at 1 August 2022. The reference amounts and the coverage rates used to calculate this definitive balance are defined in the deliberation of 17 November 2016 deciding on TURPE 5 HTB.

2.2.4 Calculation of the K coefficient for the reconciliation of the CRCP balance

The annual tariff update, as at 1 August of year *N*, uses a coefficient K, which aims to reconcile, as at 31 July of year *N+1*, the CRCP balance as at 1 January of year *N*. The coefficient K is capped at +/-2%.

The K coefficient is determined each year so as to enable the tariff change effectively implemented to cover, within the limit of its cap, the sum of the following costs to be recovered:

- the smoothed allowed revenue for year *N* defined by the present deliberation, indexed to inflation;
- the forecast reconciliation of the CRCP balance, for year *N*.

The forecast revenues resulting from the application of the tariffs effectively implemented over this period are based on assumptions of energy injections and withdrawals and power subscribed in RTE's network.

2.3 Incentive regulation for controlling costs

2.3.1 Incentive regulation for operating expenses

2.3.1.1 Absence of CRCP coverage for the majority of operating expenses

TURPE 5 HTB provides for a 100% incentive on net operating expenses, with the exception of certain predefined items: CRE therefore defines a trajectory for the tariff period, and RTE bears or benefits from any differences compared to this trajectory.

Given the positive results over the last ten years and the favourable feedback from participants to the public consultations of 14 February 2019 and 1 October 2020, CRE is re-adopting this principle for the TURPE 6 HTB tariff.

Therefore, with the exception of the expense and revenue items fully or partially covered through the CRCP, presented in section 2.3.3 of the present deliberation, RTE will bear or benefit from any difference compared to the trajectory set for the TURPE 6 period.

2.3.1.2 Mechanism on asset management expenses

The average age of the electricity transmission network is close to 50 years. The matter of the natural ageing of network assets and their renewal is therefore becoming increasingly important for the French electricity system.

In addition to the mechanical ageing of assets, RTE explains that it has noticed a more advanced state of disrepair than expected of certain assets and therefore plans to accelerate the renewal and maintenance of the assets concerned. This is particularly the case of structures with premature erosion in certain regions ("erosion" plan) and gas-insulated substations (GIS) whose sealing system is deteriorating faster than anticipated, which generates large emissions of SF_6, which is a greenhouse gas ("GIS" plan).

The grid renewal strategy envisaged by RTE is based first and foremost on a more effective management of network structures. Assets will be managed individually depending on their condition, which will lead to lengthening the lifetime of some components that can still be used and reducing the lifetime of less effective assets. This search for optimal solutions for assets' life cycles can change the ratio between operating expenses (OPEX) and capital expenses (CAPEX).

The effort devoted to grid renewal will intensify gradually, both through increased investment needs and a stronger repair and maintenance policy. CRE considers that this approach is relevant because poor maintenance of assets carries the risk of significant increases in investments in the future in response to insufficient maintenance.

According to RTE, the investment expenses devoted to grid renewal would total roughly an average €500 million/year over the next 15 years, compared to roughly €350 million/year over the 2016-2020 period. In addition, the effort to repair, maintain and rehabilitate structures aimed at extending their operational life results in a significant increase in operating expenses.

Within the framework of the examination of RTE's TYNDP, CRE is in favour of the principles of the asset management policy proposed by RTE, since it enables the maintaining of the quality of supply and the long-term optimisation of investment and operating expenses, and thus in the long run, a lower cost for users. In compliance with these principles, CRE considers that it is relevant to take into account, in the determination of the allowed revenue, the increase in the volume of work and activities identified by RTE as necessary to meet its needs. Therefore, in its public consultation of 1 October 2020, CRE stated its willingness to accept, for these items, sharp increases in OPEX trajectories over the TURPE 6 period compared to the levels spent during TURPE 5 HTB.

However, since there is an incentive on the OPEX trajectory, the non-execution of work volumes initially planned could give rise to undue benefits for RTE. CRE therefore considers that granting the OPEX increase must necessarily be accompanied by a regulatory framework protecting users in the event of non-execution of work and activities projected by RTE in its tariff proposal.

In its public consultation of 1 October 2020, CRE proposed implementing a specific regulatory mechanism associated with the effective execution of work and activities having served to build the TURPE 6 HTB trajectories. All participants that took part in the public consultation are in favour of the increase in financial trajectories relating to asset management being dependent on the achievement of the underlying operational objectives.

The present deliberation introduces a specific regulatory mechanism for the asset management based on the following principles:

- each year, RTE will transmit to CRE a follow-up report on all asset management expenses (technical and financial statement) as well as a follow-up report on the investments associated with the relevant plans and programmes;
- at the end of the TURPE 6 period, CRE will review the volumes of work effectively conducted by RTE in comparison with the reference trajectory of volumes listed in the confidential annex 6, defined on the basis of RTE's tariff proposal. If RTE has not executed all of the operations planned over this period within the framework of its asset management policy, the forecast expenses associated with the operations not carried out will be returned to grid users, which will be equal to the volumes not executed multiplied by the unit costs used to construct the tariff trajectory;
- this mechanism concerns four expense items:
  - the "GIS" plan;
  - the "corrosion" plan;
  - the substation rehabilitation and replacement policy;
  - the line rehabilitation and replacement policy;
- since each plan and policy has several types of operations, counterbalancing of operations within the same plan or same policy is authorised. This is not possible between plans and policies.

This specific regulation will cover approximately 30% of asset management OPEX and more than half of their increase compared to TURPE 5 HTB. The confidential annex 6 of the present deliberation specifies the operational terms for applying this mechanism, all of the cost items followed and subject to the incentive as well as the associated reference volumes and unit costs.

2.3.1.3 Incentive regulation for loss compensation expenses

In accordance with the provisions of Article L. 321-11 of the energy code, RTE freely negotiates with producers and suppliers of its choice contracts to procure energy and capacity to compensate power losses in its grid, based on competitive, non-discriminatory and transparent procedures such as public consultations and the use of organised markets.

Power losses in the public transmission grid for the TURPE 5 period represents about 11 TWh per year and an average €470 million in costs per year, i.e. 11% of RTE's allowed revenue. The coverage of costs to compensate power losses in the grid therefore has a major financial impact.

TURPE 5 HTB had introduced a mechanism aimed at incentivising RTE to control the cost of purchasing energy and capacity to compensate losses, dealing on the one hand with the loss volumes, and on the other hand, with the average price of purchasing energy and capacity to compensate losses. Indeed, although certain factors, over which RTE has little influence, have an impact on power losses and the costs of their compensation (weather conditions, production plans and exchanges at interconnections for example), CRE considers that RTE has levers at its disposal to act both on volumes (topology measures, coordination of maintenance schedules, etc.) and on the prices for purchasing energy and capacity (through an efficient procurement policy) to compensate losses.

The incentive mechanism in effect during the TURPE 5 period consists:

- for volumes: in comparing the annual volume of losses recorded by the operator with a reference volume determined each year by the product of the reference loss rate, set at 2.10% for TURPE 5 HTB and the volume of total injections in the transmission network. The operator keeps, or bears as the case may be, 10% of the difference in volumes valued at the operator's average purchase price for losses;
- for the average purchase price for losses: in comparing annually the purchase price of energy and capacity for RTE's loss compensation with a unit reference price determined each year using market prices recorded for a basket of reference products as defined in a confidential annex to the deliberation deciding on the TURPE 5 HTB tariff. The operator keeps, or bears as the case may be, 20% of the difference between the reference cost, which takes into account the reference price and the actual volume, and the actual cost.

Lastly, an annual cap on the overall bonus/penalty received for both incentive mechanisms is planned and set at €10 million per year.

CRE considers that this mechanism effectively incentivises RTE to control the volume of losses in the transmission grid and optimise its procurement strategy.

Therefore, in its public consultation of 1 October 2020, CRE proposed maintaining the mechanism in the TURPE 6 HTB while updating it marginally.

Concerning the incentive regulation for the purchase price for compensation of losses in the grid, most contributors to the public consultation of 1 October 2020, including RTE, are in favour of the developments presented by CRE. Concerning the changes proposed concerning the incentive regulation for loss volumes, participants' opinions were mixed. While several participants are in favour of CRE's proposal, others, including RTE, consider that the operator does not have sufficient control over the volumes of losses for this mechanism to be effective. RTE also contests the reference loss rate envisaged by CRE, since it would not take into account upcoming developments in the network, particularly with the commissioning of new interconnections and the development of renewable energy.

CRE considers that the incentive rate it proposes for TURPE 6 HTB, limited at 20%, reflects RTE's partial control over the volume of losses in the transmission grid. Moreover, CRE considers that the reference trajectory of volumes must be based on objectifiable data and therefore adopts an approach based on past volumes and not on projections. However, compared to the analysis conducted to build the reference trajectory in TURPE 5 HTB, CRE shortened the period taken into account to consider only the most recent past.

In the light of all of these elements, CRE implements, for the TURPE 6 period, the developments described in its public consultation of 1 October 2020 and reiterated below.

Incentive regulation mechanism for loss volumes

The mechanism relating to the incentive on the volume of losses for TURPE 6 HTB is based on the following principles:

- the reference loss rate used in the calculation of the reference loss volume is set at 2.20% of the volume of total injections in the transmission grid (versus 2.10% under TURPE 5), in line with the average loss rate seen in the transmission grid over the years 2016 to 2019;
- RTE is incentivised on the volume of losses in the transmission grid at the rate of 20%;
- the difference between the reference volume and the actual volume is valued at the reference average price for the purchase of energy and capacity to compensate losses (see below).

Incentive regulation mechanism for the average price of loss compensation

The principle of the mechanism relating to the regulation of the average price of loss compensation for TURPE 6 HTB remains identical to the one established for the TURPE 5 period, i.e. a strategy of progressive coverage of the price risk, by regularly purchasing quantities whose cumulated value can cover the total annual volume of losses, in energy and capacity.

However, the terms for purchasing capacity guarantees in the reference strategy have changed for TURPE 6 HTB, in order to better take into account actual auctions taking place in the capacity market, both in terms of prices and frequency.

In addition, the costs and risks inherent to the activity of loss coverage by system operators (e.g. transaction costs, effects of a market with imperfect liquidity) were incorporated in the TURPE 5 HTB model through a premium applied to the reference price calculated by the model. This premium is revalued for the TURPE 6 period to take into account the change in these risks.

The methodology for calculating the reference purchase price for the reference loss compensation for TURPE 6 HTB is contained in the confidential annex 5 to the present deliberation.

Cap and follow-up of the incentive regulation for the loss compensation mechanism

The cap on the overall incentive is set at €15 million/year for the TURPE 6 period, i.e. 0.3% of RTE's average allowed revenue over this period, in line with the relative level of the cap applied to Enedis.

2.3.1.4 Incentive regulation for costs of balancing reserves contracted

In accordance with the provisions of Article L.321-11 of the French Energy Code, RTE ensures that the reserves necessary for grid operation are available and operational. RTE thus constitutes reserves by prescription (for the Automatic Frequency Restoration Reserve – aFRR) or by concluding contracts ahead of real time (for the Frequency Containment Reserve – FCR, the Manual Frequency Restoration Reserve – mFRR and the Replacement Reserves – RR). Then, RTE activates the offers either on a balancing market or pro-rata (for the aFRR) to re-constitute ancillary services or margins for the different time periods. All of these costs represent, for the TURPE 5 period, a cost of roughly €200 million per year on average.

During the TURPE 5 period, CRE set up an incentive regulation on the volumes of all balancing reserves to incentivise RTE to control its balancing costs while fully covering it from the "price effect". The costs for constituting reserves were thus fully included within the scope of the CRCP in TURPE 5 HTB, but a bonus/penalty scheme for volumes was introduced in order to incentivize RTE on its costs..

The terms for contracting balancing reserves evolved during the TURPE 5 period, and new developments should be expected for the TURPE 6 period, in line with the European regulations or driven by CRE's requirements to improve the technical and economic efficiency of the balancing mechanism. The cost of balancing reserves is therefore subject to uncertainty.

While RTE does not have a perfect control and a foreseeability of these costs, it does have numerous levers to control their evolution. RTE can optimize the sizing of the different reserves, innovate with new products to improve balancing at a lesser cost or improve the market rules to promote the arrival of new players for the supply of these reserves or the European integration of the balancing market. The cost of balancing reserves dropped sharply during TURPE 5 HTB, from €238 million in 2017 to €196 million in 2019, i.e. a roughly 18% decrease. Multiple factors are behind this drop, but CRE considers that the principle of incentivising RTE was beneficial. However, the review of the mechanism in effect over the TURPE 5 period shows that an incentive on only the volumes, independently of prices, can give rise to premiums that are unrelated to the actual cost for grid users.

In this context, CRE proposed, in its public consultation of 1 October 2020, to incentivise RTE to control the cost of contracting all of the reserves for the TURPE 6 period, with an incentive rate limited to 20% to take into account the operator's partial control over this cost item.

Most participants were in favour of this proposal. A few participants however expressed reservations about RTE's little control over factors determining the cost of contracting reserves. RTE highlighted in particular, that reserve prices will all be based on market prices for TURPE 6 HTB, over which it has no leverage, and that reserves' volumes should increase in the middle term, in line with the evolution of the power mix and the provisions specified by the European codes for security criteria. Nevertheless, CRE reaffirmed that RTE, through the abovementioned levers, can control to a certain extent the evolution in reserves' contracting costs.

Therefore, the present deliberation introduces for TURPE 6 HTB an incentive mechanism for the cost of contracting all reserves, based on the following principles:

- a reference trajectory encompassing the costs of all reserves , including all balancing operations for the reconstitution of ancillary services (including balancing operations as a result of a balancing entity's failure, and those due to balancing generating a loss in the activated actor's ancillary services) and margins, is defined in the present deliberation (see section 3.1.2.3.2). CRE will update this reference trajectory each year from next year for the following year, taking into account:
  - the evolutions in the market prices and the contracting terms in the balancing market;
  - the evolutions of the sizing of the reserves and the types of products that will be adopted by CRE, in connection with the expected improvement in the technical and economic efficiency of the balancing mechanism;
- for each year *N+1*, this update will take place in Q4 of year *N* in order to have the best up-to-date vision of the balancing market, in collaboration with RTE and shared with all market participants through an *ad hoc* annual deliberation;
- the difference between the updated trajectory and the initial trajectory is fully covered by the CRCP;
- a 20% incentive rate is applied to the overall cost, which will limit the risk faced by the operator, since the differences between the reference trajectory and the reserve constitution costs effectively recorded will be covered 80% through the CRCP;
- the amount borne or kept by RTE under this mechanism is capped at €15 million/year.

2.3.1.5 Incentive regulation for congestion costs

Congestion corresponds to a situation where there is a physical constraint in the grid. Most of the time, the constraint corresponds to the risk of a lasting overload of an electrical line in the case of a loss of another grid element (grid sizing and operations in N-1). Two types of congestion can occur in the transmission network:

- national congestion, which are constraints in RTE's grid that it manages alone;
- international congestion, which are constraints in RTE's or in the neighbouring TSO's grids that require joint management by RTE and its neighbours.

Over the TURPE 5 period, there is a 100% incentive on national congestion costs since this type of congestion is relatively foreseeable and controllable by RTE, while international congestion costs are, in contrast, fully compensated in order to incentivise RTE to maximise the capacity available at interconnections.

For the TURPE 6 period, CRE identified several challenges:

- the growing integration of renewable energy in public electricity transmission and distribution grids makes grid adaptations necessary. Within this framework, the use of optimum sizing as proposed by RTE in the TYNDP will gradually be accompanied by the periodic implementation of generation limits and will therefore lead to an increase in national congestion costs;
- the establishment of methodologies for sharing international congestion costs (redispatching and countertrading) at European level, currently under negotiation, combined with the increase in cross-border capacity made available to the market and the application of the 70% rule for cross-border exchanges, could result in an increase in these costs, particularly because of the risk of a partial transfer of congestion costs from neighbouring countries to France.

In its tariff proposal, RTE anticipates a significant rise in congestion costs over the TURPE 6 period – an average €44 million/year compared to an average €12 million/year over TURPE 5.

In this context, CRE proposed, in its public consultation of 1 October 2020, revising the current mechanism which it deems unsuited to the challenges identified for the TURPE 6 period. CRE therefore proposed setting the same incentive on national and international congestion, at 20% of all costs. This incentive regulation must, in particular, serve to balance the incentives given to RTE to, on the one hand, develop flexibility (impact on national congestion) and, on the other hand, limit the costs transferred by neighbouring countries (impact on international congestion).

Most participants were in favour of this incentive mechanism, sharing the arguments put forward by CRE. RTE however, was not in favour of the implementation of an incentive on international congestion, considering that the 70% rule for cross-border capacity will generate additional international congestion difficult to foresee given the uncertainty surrounding the final cost-sharing methodology that will be adopted at European level.

CRE reiterates however that the cost-sharing methodology will not be effective during TURPE 6 HTB and that the reference international congestion cost trajectory adopted by CRE complies with RTE's proposal and therefore incorporates assumptions of an increase compared to the average level observed during TURPE 5 HTB.

Therefore, CRE decides, within the present deliberation, to set a 20% incentive on RTE's national and international congestion costs for the TURPE 6 period. The cost trajectories adopted for the TURPE 6 period are presented in section 3.1.2.3.2 of the present deliberation.

2.3.2 Incentive regulation for investments

A major increase in RTE's investment expenses is expected for the TURPE 6 period. RTE attributes these considerable investment projections to the need to renew the grids and to adapt them to energy transition requirements.

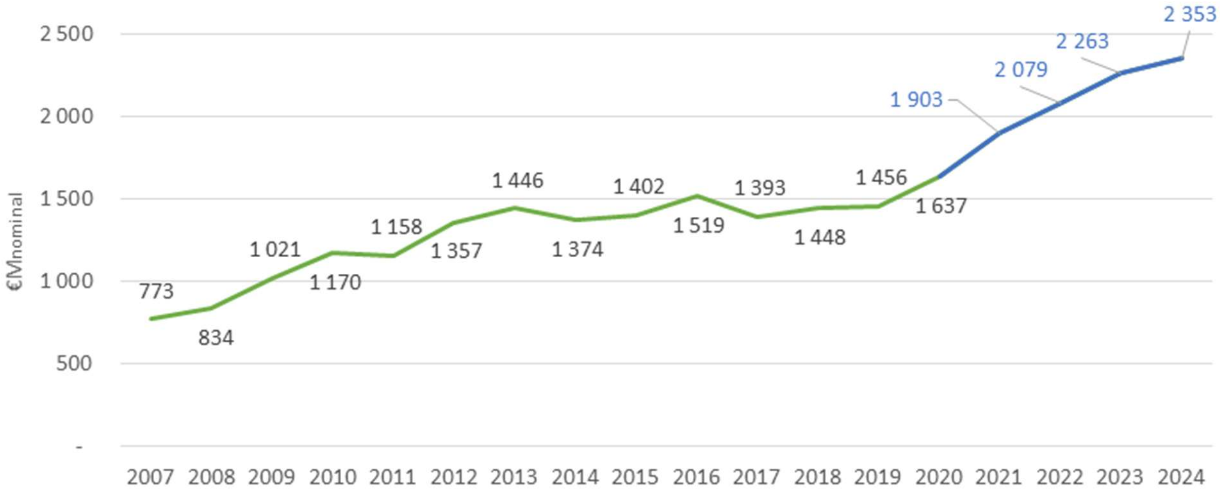

Figure 1 : RTE's actual (in green) and forecast (in blue) gross investment expenses between 2007 and 2024

During this period, continued stagnation of electricity consumption is expected, which leads CRE to be particularly attentive to the examination of all new investment projects that will be submitted by the TSO.

Article 18 of regulation (EU) 2019/943 on the internal market in electricity[29] provides for the pricing methods to give appropriate incentives, both in the short and long term, to the transmission system operators to support efficient investments.

The regulatory framework, whose role is to align as much as possible the interest of operators with that of the community, must therefore encourage RTE to prioritise and carry out the most useful investments for the community in the most cost-effective manner. In that regard, CRE reiterates that every investment project must be the subject of robust cost/benefit analyses so as to avoid passing on unnecessary costs to grid users. In order to ensure sustainability of investment expenses, CRE has changed certain aspects of RTE's incentive regulation for investments in the TURPE 6 HTB.

2.3.2.1 Incentive for controlling and prioritising investment expenses

In its examination of RTE's TYNDP, CRE considered that the transformations caused by the energy transition and the connection of renewable energy, including marine energy, and the necessary renewal of the grid require significant investments in order for the grids to accompany the energy transition and maintain their level of performance. At the same time, CRE also stated that given the magnitude of investments, it is essential for RTE to use the levers at its disposal to reduce the associated expenses, prioritise the most useful investments for the community and complete them in the most cost-effective way.

In order to meet these requirements, CRE indicated in its public consultation of 1 October 2020, that it wished to give incentive to RTE to control and prioritise its grid investment expenses, beyond the specific incentive for controlling project costs (see sections 2.3.2.3 and 2.3.2.3) which is not intended to incentivise RTE to make only the investments most useful to the community. CRE therefore proposed to establish an incentive regulation which consists in defining an envelope above which the investment costs incurred by RTE could give rise to a penalty. Most participants that answered the public consultation, including RTE, are in favour of the mechanism proposed by CRE. Among the few participants that opposed it, SER in particular, fears that, because of the mechanism, RTE will delay necessary investments in the long term for accommodating renewable energy. CRE considers that the cap is set at a sufficiently high level that prevents giving incentive to RTE to not make investments necessary for the energy transition.

The present deliberation introduces, for the TURPE 6 period, the mechanism based on the following principles:

- all grid investments will enter the AuC and then the RAB as of their commissioning and the associated capital expenses will be covered through the CRCP;

[29] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market in electricity (recast)

- TURPE 6 HTB defines a four-year envelope which is an investment cap. RTE has an incentive not to exceed this envelope, and therefore, to control its expenses and prioritise its projects:
    - if the sum of investment expenses over the tariff period is lower than this envelope, no penalty or bonus will be applied to RTE;
    - however, if the sum of investments over the tariff period exceeds this envelope, then a penalty, equal to 20% of the overrun, will be applied to RTE through the CRCP;
- the difference between the investment expenses and the envelope defined by CRE will be calculated over the tariff period, i.e. four years. A multi-annual envelope gives RTE the flexibility to manage any project delays or periodic additional costs, and to implement the multi-annual optimisation strategies necessary for controlling investment expenses;
- public or private subsidies, associated with the investments concerned by this mechanism and which RTE plans to receive, are deducted from the forecast investment expenses in order to define the envelope amount; similarly, the subsidies received by RTE will be deducted from the investments actually made during the TURPE 6 period (see section 3.1.3.2);
- in terms of scope, the envelope covers all investments with the exception of "non-grid" investment expenses, investment expenses devoted to connections of offshore wind farms and high-voltage, direct current interconnection projects. A specific regulatory framework is applied to "non-grid" investment expenses. In addition, offshore power connection projects and new high-voltage, direct-current interconnection projects are very large-scale projects, whose timetable can vary significantly and outside RTE's control, with a very substantial impact on investment expenses;
- in line with RTE's tariff proposal and excluding projects that have already been explicitly rejected by CRE[30], the cap is set at the level defined in section 3.1.3.2 of the present deliberation. The four telecommunication projects rejected are as follows: the deployment of its own telecommunication infrastructures, Hermès, site-to-site LAN, and the INUIT add-on. However, if CRE approves these projects and the projects associated with these four projects, once their technical and economic relevance has been demonstrated, the forecast expenses associated with these projects over the TURPE 6 period presented by RTE at the time of CRE's approval of the annual investment programme referred to in Article L. 321-6 of the energy code, will automatically be added to the cap;
- each year, RTE will transmit to CRE, within the framework of the assessment of the execution of the investment programme, an implementation report for year *N-1*, which will specify any differences between the actual trajectory and the forecast trajectory of net investment expenses falling within the scope of the envelope cap, and will explain the choices made in terms of the prioritisation of investments and the measures taken to comply with the envelope defined at the start of the tariff period.

2.3.2.2 Incentive to control the costs of major projects

The mechanism in effect over the TURPE 5 period specifies that grid development projects with a budget of over €30 million must be audited, enabling a target budget to be set, with a bonus or penalty attributed to the operator based on the difference between this target budget and actual expenses and with a neutrality band of +/-10% on the target budget. The bonus is equal to 20% of the difference between 90% of the target budget and actual investment expenses, and the penalty corresponds to 20% of the difference between the actual investment expenses and 110% of the target budget. CRE also extended the incentive regulation mechanism for RTE's investments to offshore wind energy connection projects by the deliberation of 24 January 2019[31].

In its public consultations of 14 February 2019 and 1 October 2020, CRE indicated its wish to maintain, for the TURPE 6 period, the incentive mechanism established over the TURPE 5 period, while reducing the neutrality band to +/-5% on the target budget and by extending the mechanism to all development, renewal and connection projects, including offshore wind farm connection projects. However, with regard to interconnection projects for which a cross-border cost allocation decision is made, CRE considers that it is relevant to maintain a neutrality band of +/-10% (see section 2.3.2.4). Most contributors, including RTE, are in favour of the mechanism proposed by CRE. RTE wishes however for the neutrality band to be adapted to each project, based on the type of project, and therefore on the risks associated.

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[30] Deliberation by the French Energy Regulatory Commission of 20 December 2018 approving RTE's investment programme for 2019: https://www.cre.fr/Documents/Deliberations/Approbation/Programme-d-investissements-2019-RTE

[31] Deliberation by the French Energy Regulatory Commission of 24 January 2019 deciding on the extension of the incentive regulation for RTE's investments to offshore wind farm connections and amending the "TURPE 5 HTB" deliberation: https://www.cre.fr/Documents/Deliberations/Decision/Extension-du-mecanisme-de-regulation-incitative-des-investissements-de-RTE-aux-travaux-de-raccordement-des-parcs-eoliens-en-mer2

For TURPE 6 HTB, for all investment projects for which the commitment decision will be made as from the publication of the present deliberation and whose estimated budget exceeds or is equal to €30 million:

- CRE will audit the budget presented by the TSO, prior to the commitment of the work-related expenses, and will define a target budget;
- regardless of the investment expenses made by RTE, the asset will enter the regulated asset base at its real value when it is commissioned (minus any subsidies);
- if the investment expenses incurred by RTE for this project are between 95% and 105% of the target budget, no bonus or penalty will be applied;
- if the investment expenses incurred are less than 95% of the target budget, RTE will receive a bonus corresponding to 20% of the difference between 95% of the target budget and the actual investment expenses;
- if the investment expenses incurred by the TSO are higher than 105% of the target budget, RTE will be applied a penalty of 20% of the difference between the actual investment expenses and 105% of the target budget.

In compliance with the connection agreement model approved by CRE on 8 November 2018 regarding tenders 1 and 2[32] and the specifications of the competitive dialogue procedure No 1/2016 covering offshore wind power generation facilities in an area off the coast of Dunkirk (tender 3), it is specified that the retained applicant must constitute financial guarantees to cover the risk of stranded costs. Therefore, in the case of a failure of an applicant, RTE will bill this candidate the stranded costs it bears, and will, as needs be, withdraw the relevant amounts from the financial guarantees. In order to prevent grid users from bearing the costs that moreover will have been covered by the defaulting winner of the tender, CRE specifies that in the event of a failure by a winner of a tender for the construction of an offshore wind farm before the connection is commissioned, RTE's investment expenses in the connection of the wind farm concerned will not be included in AuC during the period between when the first winner defaults and when a new winner will have advanced to a level of work comparable to that reached by the first winner at the time of its failure.

At this stage, the envelope for projects concerned by the incentive for controlling the costs of major projects during TURPE 6 HTB is estimated at approximately €3.1 billion.

In addition, the projects for which an incentive regulation was defined during the TURPE 5 period will keep the regulatory treatment of that period.

2.3.2.3 Incentive to control the costs of grid projects excluding major projects

The incentive mechanism for controlling the costs of projects of an amount greater than or equal to €30 million described in section 2.3.2.2 of the present deliberation concerns a limited number of projects.

In its public consultations of 14 February and 1 October 2020, CRE proposed an incentive mechanism based on the selection, by CRE, and without any predefined criteria, of a few projects or project categories whose budget is lower than the €30 million threshold, in order to audit their budget and apply an incentive regulation identical to that applicable to investment projects whose budget exceeds or is equal to €30 million.

Most contributors to the public consultation of 1 October 2020 were in favour of the mechanism proposed by CRE. Some of them however wished to draw CRE's attention to the implications of multiplying the number of projects subjected to an audit.

The present deliberation introduces this incentive mechanism.

2.3.2.4 Incentive for new interconnection capacity projects

The regulatory framework of TURPE 5 HTB provides for an incentive mechanism aimed at encouraging the realisation of interconnection projects that are economically relevant for the community, in the most cost-efficient manner.

The incentive mechanism is based on three distinct incentives:

- a financial incentive for constructing interconnections within the shortest possible time, reflected in the attribution of a fixed bonus paid upon the commissioning of the project;

[32] CRE deliberation of 8 November 2018 approving the model of specific conditions relating to the "Implementation and funding of connection infrastructure", of the agreement for connection to the public electricity transmission grid of production from offshore renewables that have been subject to a competitive tendering procedure mentioned in article L. 311 10 of the energy code for which the adopted applicants were designated before 1 January 2015: https://www.cre.fr/Documents/Deliberations/Approbation/Conditions-particulieres-relatives-a-la-Realisation-et-financement-des-ouvrages-de-raccordement-de-la-convention-de-raccordement-au-reseau-pub

- an incentive for the minimisation of project implementation costs, taking the form of a bonus or penalty, based on the difference between the project's target budget and actual investment expenses;
- an incentive for the use of the installation, taking the form of a bonus or penalty, based on the difference between actual flows and flows initially forecasted by CRE.

The mechanism also provides for two remuneration floors to reduce the TSO's risk in the event of unfavourable circumstances possibly leading to major penalties:

- if the actual flows are lower than the initially projected flows, the penalty corresponding to the use of the installation cannot exceed the fixed bonus defined by CRE prior to the expense commitment decision;
- if the actual cost exceeds the target budget, the penalty is limited so that all of the cumulated incentives cannot lead to a project rate of return lower than the WACC - 1%.

In its public consultation of 1 October 2020, CRE proposed maintaining the mechanism in effect in TURPE 5 HTB, while simplifying it and keeping only one floor covering all three incentives.

Indeed, CRE noted that, for the Celtic Interconnector and the Biscay Gulf Interconnector projects, the floor regarding the sum of the fixed bonus and the incentive for the use of the installation does not enable the appropriate setting of the incentive for the use of the interconnection, once the fixed bonus is set at nil. However, the incentive for the use of the installation is important since it gives the TSO an incentive (i) to complete projects whose benefits for the community are considerable and to maximise the reliability of its cost/benefit analyses and (ii) to maximise the availability of the installation, which can bring benefits to the community.

Contributors to the public consultation were divided with regard to CRE's proposal. While some of them consider simplification desirable, others thought that the incentive for the effective use of the installation is not very relevant in practice and is difficult to apply, because the use of the interconnection is out of the TSO's control. CRE considers that an incentive based on actual flows is necessary to ensure that a large bonus is not granted to a project that ultimately is of no use to the community.

Given all of these elements, CRE decides that the incentive mechanism for new interconnection capacity projects for the TURPE 6 HTB period will be based on three incentives:

1. the financial incentive for constructing interconnections within the shortest possible time is reflected in the attribution of a fixed bonus, expressed in constant euros, the amount of which is defined by CRE prior to the TSO's commitment decision. This fixed bonus is calculated based on the benefit for the community estimated by CRE on the basis of a cost/benefit analysis of the project. It is paid only after the project is commissioned, which is an incentive for completing the investment within the shortest possible time;
2. the incentive for the minimisation of project implementation costs, taking the form of a bonus or penalty, based on the difference between the project's target budget and actual investment expenses;
    - if the investment expenses incurred by the TSO for this project are between 90% and 110% of the target budget, no bonus or penalty will be applied;
    - if the investment expenses incurred are less than 90% of the target budget, the TSO will receive a bonus equal to 20% of the difference between 90% of the target budget and the actual investment expenses;
    - if the investment expenses incurred are higher than 110% of the target budget, the TSO will be applied a penalty of 20% of the difference between the actual investment expenses and 110% of the target budget;
3. the incentive for the use of the interconnection takes the form of a bonus or penalty, calculated at the end of each year as from the commissioning of the installation, the level of which depends on actual flows compared to the flows initially forecasted by CRE. The bonus or penalty is applied during the first ten years of operation of the infrastructure.

If the actual cost exceeds the target budget, or if actual flows are lower than the flows initially projected by CRE, the amount of the penalty over the TSO's overall remuneration is limited so that all of the cumulated incentives cannot lead to a project rate of return lower than the WACC - 1%.

The parameters used to calculate bonuses and penalties will be set in an *ad hoc* tariff decision relating to each project concerned, as was the case within the framework of TURPE 5 HTB.

Lastly, CRE considers that the target budget must be set when the decision is made to undertake the project, i.e. for example, when the cross-border cost allocation decision is made, if this applies to the project. This will better align the cost target with the amount on which the project decision is based. In order to not expose the TSO to a major risk linked to setting the target budget too early, CRE decides to apply, in this case, a neutrality band of +/- 10% around the target budget.

2.3.2.5 Incentive for controlling costs of "non-grid" investments

TURPE 5 HTB introduced a mechanism incentivising RTE to control its capital expenses similar to its operating expenses over a scope of investments referred to as "*non-grid*" investments including assets such as real estate, light vehicles and information systems. In consists in defining, for the tariff period, the trajectory of capital expenses associated with these investments, which are excluded from the scope of the CRCP. At the end of the period, the effective value of these fixed assets is included into the RAB.

The goal is that, for these three items for which arbitration between investment and operating expenses is possible, RTE will have the same incentive concerning both OPEX and CAPEX.

This mechanism fulfilled its role over the TURPE 5 period, since no difficulty or misapplications were observed and RTE had an effective incentive for its OPEX and CAPEX. Therefore, CRE proposed, in its public consultation of 1 October 2020, to maintain the mechanism.

Most stakeholders who expressed their view on this topic during the public consultation are in favour of maintaining the mechanism and invite CRE to pursue its reflections on the implementation of an *ad hoc* mechanism for information system expenses since this will represent a major cost item in the future.

The mechanism for TURPE 6 HTB is therefore the same as for TURPE 5 HTB. It consists in defining for the tariff period, the trajectory of capital expenses associated with real estate, light vehicle and information system investments and excluding them from within the scope of the CRCP. The differences between the reference capital expenses and the effective expenses will be kept fully by RTE.

Throughout the TURPE 6 period, the capital expenses for these categories of assets will be calculated using the projected book values defined in the present deliberation. At the end of the tariff period, the effective value of AuC and assets put into service during this period will be taken into account in the AuC and the RAB, and therefore used for the calculation of normative capital expenses to be recovered, which will enable the sharing of gains or extra costs with users for the next tariff periods.

With regard to the scope of projects covered by this mechanism, CRE decides to exclude the projects relating to telecommunication networks since these projects are closely associated with RTE's grid investment strategy, as well as the Lille and Marseille real estate projects (see section 2.3.2.6). If these projects are validated within the framework of the approval of RTE's investment programmes, and if the associated expenses exceed €30 million, these projects will be subject to incentive regulation for controlling the costs of major projects (see section 2.3.2.2).

The amount of investments subject to this incentive mechanism is €209 million/year, i.e. roughly 10% of the total investments planned by RTE over the TURPE 6 period.

2.3.2.6 *Ad hoc* regulatory framework for the Lille and Marseille property projects

RTE's investment expenses related to its real estate holdings totalled roughly €60 million per year over the 2017-2019 period and breaks down into (i) residential housing for employees, (ii) routine projects corresponding to major maintenance, redevelopments and light renovations, and (iii) exceptional projects. The latter concerns rehabilitation and construction projects and represented approximately 80% of RTE's real estate- related investment expenses over the TURPE 5 period. Over the TURPE 6 period, RTE plans to spend an average €81 million per year on real estate investments. According to RTE, the portion of exceptional projects in the real estate- related investment expenses should remain the same, at 80%.

Among these "exceptional" projects, RTE plans in particular for the construction of the Lille and Marseille regional headquarters in order to bring together employees currently distributed across several locations, at a single regional site. The investment expenses for these projects should amount to a total of €144 million. The construction work for these two real estate projects was initially scheduled for the 2021-2025 period and RTE planned to sell the sites it currently occupies in 2025.

In its public consultation of 1 October 2020, CRE noted that, in Lille and Marseille, the economic relevance of these relocation projects resided mainly, given RTE's analyses, in the increased value in the long term (in the case of selling) of the two new buildings that RTE would have acquired, as well as in the investments in the existing sites that would have been avoided, as these investments would not have added any value to the sale of these sites according to RTE.

In this context and in the light of the significant expenses for the construction of the Lille and Marseille regional headquarters, CRE considers, on the one hand, that these projects should not pose an unjustified risk to grid users regarding the long-term valuation of these sites, and on the other hand, that these two projects should not result in the short-term increase of expenses to be covered by the transmission tariff. Therefore, in its public consultation of 1 October 2020, CRE proposed establishing an *ad hoc* regulatory framework for these two real estate projects, which would therefore no longer be subject to the tariff framework relating to the treatment of real estate asset disposals (see section 2.1.2.4.2).

However, stakeholders' opinions were divided in the public consultation of 1 October 2020 regarding the implementation of the *ad hoc* regulatory framework envisaged by CRE. Employee unions and grid operators in particular, highlighting the risk of insufficient coverage of costs, were not in favour of the proposal.

Therefore, CRE decides not to introduce the mechanism proposed in the public consultation.

In addition, RTE recently informed CRE of the difficulties encountered in carrying out these projects, causing major delays. With regard to Marseille, the project initially proposed by RTE has been compromised and a new site selection procedure is in progress.

Given the uncertainties surrounding these projects, CRE requests RTE to once again submit these projects for approval when this uncertainty is lifted. Furthermore, CRE decides to not include these projects within the scope of the incentive for controlling "non-grid" investment costs. The capital expenses associated with these projects will therefore be covered in the CRCP.

Lastly, CRE will apply to these projects the incentive for controlling the costs of major grid projects specified in section 2.3.2.2.

2.3.2.7 Grid use indicators

While RTE projects a major increase in its investments in the upcoming years, it is essential to ensure that operators' investment and operating expenses are justified and useful for the community. To do so, it is valuable to be able to assess the use of the grid and its evolution, especially since the emerging new flexibility can theoretically improve its use. It is with this in mind that in its public consultation of 14 February 2019, CRE requested system operators to work on the definition of follow-up indicators for the use of infrastructure which would then be transmitted regularly. Such indicators must enable a better understanding of the evolution of grid structure and use over time.

To this end, CRE and RTE worked to define indicators to follow the use of the public transmission grid in order to have a vision of the flows in the network.

All connections are operated based on standard ampacity (maximum current-carrying capacity) which is used to define flow capacity in accordance with averaged local and seasonal weather conditions. Since ampacity calculation also includes load duration curves, and the network is sized for full grid operation (in *N*) and in operation in case of hazards (*N-1),* it is natural to have transit values per connection notably lower than the ampacity of the connection, on an annual average. However, in order to clarify the importance of monitoring grid use, an approach based on ratios between effective and maximum ampacities is envisaged.

In its public consultation of 1 October 2020, CRE proposed implementing and following four indicators based on actual flows in the transmission network:

- the average flow in the grids power lines;
- the percentage of lines never reaching 10% of their ampacity during the year;
- the percentage of lines reaching at least 50% of their ampacity during the year;
- the average percentage of hours where 50% of ampacity is reached.

Most contributors to the public consultation are in favour of this proposal.

Each year, as from the entry into effect of TURPE 6 HTB, RTE will submit to CRE, by 1 April of each year at the latest, the results of these four indicators as well as, for each transmission grid line and hour, the data relating to the effective and maximum ampacities.

2.3.3 Coverage of certain items in the CRCP

Network tariffs are calculated using revenue and expense assumptions that serve to define trajectories for the different items over the entire period covered by these tariffs.

As indicated in section 2.1.3 of the present deliberation, an *ex post* adjustment mechanism, the expenses and revenues clawback account (CRCP), takes into account the differences between actual expenses and revenues on the one hand, and projected expenses and revenues for certain items previously identified, on the other hand.

In its public consultation of 14 February 2019, CRE re-specified the principles concerning the incentive for different expense and revenue items in the infrastructure tariffs. Therefore, the inclusion of an item in the CRCP is based on the following two factors:

- predictability: a predictable item is an item for which it is possible, for the operator and for CRE, to predict with reasonable confidence, the level of costs incurred and the revenues perceived by the operator over a tariff period;
- control: a controllable item is an item for which the operator is able to control the level of expenses/revenues over the course of a year, or has a power or influence with regard to its level, if it results from a third party.

These principles were shared widely by the contributors to the public consultation.

On this basis, in its public consultation of 1 October 2020, CRE presented the CRCP scope it intended to adopt for TURPE 6 HTB. The public consultation participants are generally in favour of CRE's proposal. Some participants suggested a few modifications with regard to the inclusion of certain items in the CRCP, such as normative capital expenses related to information systems and costs related to the interTSO compensation mechanism.

With regard to information systems, CRE considers that the regulatory framework which would apply to them is likely to promote the most optimal choice between OPEX and CAPEX (section 2.3.2.5.). In addition, CRE highlights that the IS CAPEX linked to grid digitalisation will be fully covered in the CRCP and will not be included in this incentive mechanism. In addition, CRE has not adopted the inclusion in the CRCP of costs related to the InterTSO mechanism requested by certain participants, including RTE, who consider that the TSO has little to no influence over this expense item. For such an item that has not seen any major change in several tariff periods, a stable regulatory framework should be maintained between tariff periods.

The items included within the scope of the CRCP for TURPE 6 HTB, which have not changed compared to TURPE 5 HTB, are as follows:

- for the following expense and other related items:
  - the normative capital expenses borne by RTE fully covered, with the exception of those that are concerned by the incentive regulation mechanism for "*non-grid*" capital expenses, and for which only the inflation difference is taken into account in the CRCP (see section 2.3.2.5);
  - the expenses related to loss compensation, fully covered, and subject moreover, to an *ad hoc* incentive regulation (see section 2.3.1.3);
  - expenses related to the implementation of the interruptibility mechanism, fully covered;
  - R&D operating expenses, based on specific conditions (see section 2.5.1);
  - the amounts adopted for the mechanism for taking into account smart grid industrial deployment projects (see section 2.5.2), fully covered;
  - the cost of studies not followed through relating to large projects previously and explicitly approved by CRE, fully covered;
  - any balances, positive or negative, in the suppliers' capacity imbalance settlement account and the imbalance settlement account of capacity portfolio managers;
- for the following revenue and other related items:
  - the revenues received by RTE as part of all the tariff components, fully covered;
  - revenues from interconnection capacity allocation and revenues from capacity mechanisms (designated henceforth as "interconnection revenues"), net of compensation paid by RTE in case of capacity curtailments at interconnections, fully covered;
  - net revenues related to contracts between TSO, fully covered;
- for the financial incentives generated by the following incentive regulation mechanisms;
  - incentive relating to the cost for compensating power losses in the transmission grid (see section 2.3.1.3);
  - incentive for controlling the costs of major grid investment projects (see section 2.3.2.2);
  - incentive for new interconnection capacity projects (see section 2.3.2.4);
  - incentive relating to the continuity of supply (see section 2.4.2).

In addition, CRE decides to extend the CRCP mechanism to the following items:

- rebalancing costs and any penalties paid by capacity mechanism actors, fully covered;
- gains made from the disposal of real estate and land, 80% covered;
- the costs for contracting flexibility for the purpose of congestion management within the framework of calls for tenders to be conducted by RTE in accordance with the roadmap validated by CRE during the examination of the TYNDP, fully covered;
- the compensation paid to offshore wind energy producers if the connection deadline is missed or in case of damage or dysfunctions in the connection installations leading to a partial or total limit on production. In compliance with the provisions of the order of 10 November 2017[33], CRE will determine the amount of compensation to be borne by RTE within the limit of 40% of the payments made, and within the limit of a cap of €70 million per calendar year;
- reductions, penalties and compensation related to the interruptibility mechanism and voltage ancillary services, fully covered.

Moreover, compared to the mechanism in effect in TURPE 5 HTB, CRE decides to modify the conditions for covering the following items:

- the expenses associated with national and international congestion, covered 100% and 0% respectively in TURPE 5 HTB, will be 80% covered in TURPE 6 HTB (see section 2.3.1.5);
- the balancing reserve constitution expenses[34], fully covered in TURPE 5 HTB, will be 80% covered in TURPE 6 HTB (see section 2.3.1.4);
- reductions, penalties and compensation related to balancing services, fully covered in TURPE 5 HTB, will be 80% covered in TURPE 6 HTB, in line with the regulatory treatment adopted for expenses for constituting and reconstituting balancing reserves (see section 2.3.1.4);
- the net book value of assets demolished, fully covered in TURPE 5 HTB, is governed by a specific framework in TURPE 6 HTB, in line with the tariff coverage conditions adopted in the ATRT7 and ATRD6 tariffs (see section 2.1.2.4.2);
- the compensation paid by RTE to DSOs for long outages, fully covered beyond €15 million in TURPE 5 HTB, will be fully covered above €9 million in TURPE 6 HTB (see section 2.4.2);
- the expenses and revenues at the interface between RTE and new exempted interconnections were fully covered in TURPE 5 HTB. This item included the congestion costs generated by flows circulating on this type of assets, the compensation paid by RTE in the case of cross-zonal capacity curtailments as well as the revenues coming from any payments by operators of such assets to RTE when a profit-sharing mechanism is implemented. For the TURPE 6 period, the congestion costs generated by flows circulating on this type of assets will be included in the item relating to national and international congestion costs and will therefore be 80% covered. The compensation paid by RTE in the event of cross-zonal capacity curtailments will be excluded from the scope of the CRCP, like the existing regulatory treatment regarding compensation paid by RTE to its other clients when it does not comply with its contractual commitments relating to programmed interruptions. Lastly, the revenues coming from any payments by operators of such assets, when a profit-sharing mechanism has been implemented, remain fully covered in the CRCP.

In addition, in accordance with the introduction of new mechanisms, CRE decides to include in the CRCP:

- the bonuses and penalties relating to the asset management mechanisms. In that regard, at the end of the TURPE 6 period, CRE will review the volumes of work effectively conducted by RTE in comparison with the reference trajectory of volumes listed in annex. If RTE has not performed all of the operations planned over this period within the framework of its asset management policy, the forecast expenses associated with the operations not performed will be returned to grid users, and will be equal to the volumes of work not performed multiplied by the unit costs used to construct the tariff trajectory, through the CRCP balance at the end of the period (see section 2.3.1.2). Moreover, the price effect of the unit costs of the sub-items "painting of pylons" and "rehabilitation of power transformers" under the asset management policy is 50% covered in the CRCP (see section 3.1.2.4.2). Therefore, 50% of the difference between the actual unit costs and the reference unit costs, defined in the confidential annex 6, applied to the work volumes performed by RTE will be partly covered in the CRCP;

[33] Order of 10 November 2017 fixing the scale and amount of the compensation set out in 4° of article L. 341-2 of the energy code, to be borne by the system operator: https://www.legifrance.gouv.fr/jorf/id/JORFTEXT000036068912/.
[34] These expenses include the costs for contracting frequency ancillary services, manual frequency restoration and replacement reserves as well as the costs for the reconstitution of ancillary services and margins.

- the penalties related to the incentive mechanism for controlling and prioritising grid investment expenses (see section 2.3.2.1);
- the bonuses and penalties related to the incentive mechanism for controlling grid project costs excluding major projects (see section 2.3.2.3);
- the capital expenses associated with the projects to acquire the Lille and Marseille regional headquarters (see section 2.3.2.6);
- any penalties generated by the incentive regulation mechanisms for the quality of data transmission and external innovation (see sections 2.5.3 and 2.5.4).

Lastly, the differences between the updated trajectory and the initial trajectory of balancing reserves (see section 2.3.1.4) and, if applicable, the voltage ancillary services (see section 3.1.2.3.2), will be fully covered in the CRCP.

2.4 Incentive regulation for quality of service and continuity of supply

Article L. 341-3 of the French energy code states that CRE "*may propose [...] appropriate short- or long-term incentives to encourage transmission and distribution system operators to improve their performance particularly as regards the quality of the electricity [...]*".

The incentive regulation for RTE's quality of service and continuity of supply aims at improving the quality of service provided to electricity grid users in the fields deemed particularly important for the proper functioning of the electricity market and grids.

2.4.1 Incentive regulation for quality of service

For the TURPE 5 period, quality of service (excluding the incentive regulation for quality of supply in section 2.4.2 and for data in section 2.5.3) was monitored by RTE through five indicators:

- customer claims (rate of response within deadlines);
- commitment thresholds relating to the quality of electricity as regards compliance with contractual commitments;
- timeframe for performing meter repair;
- access to the market (rate of availability of balancing mechanism portals and accuracy of trend data in the balancing mechanism);
- grid connections (commissioning and transmission of technical and financial proposals within deadlines).

In addition, the mechanism in effect over the TURPE 5 period, specifies that RTE must publish, once a year, the results of a satisfaction survey done on its customers. RTE submits, at least once a year, to the committee dedicated to power transmission system users (CURTE), the results of these quality indicators in order to identify the main challenges associated with quality of service.

During the consultation of 17 October 2019 on quality of service for grid users, stakeholders expressed a need for follow-up on three main topics: the average timeframes and costs for grid connection, the timeframes for installing/changing meters and voltage waveform quality.

In this context, in order to respond to the needs identified by participants, CRE suggested in its public consultation of 1 October 2020, to introduce nine new indicators for RTE and to attach a financial incentive to the indicator for compliance with meter repair intervention deadlines. Most contributors are in favour of the introduction of all of the indicators presented in the consultation. In particular, several participants reiterated the importance of the following proposals:

- follow-up of power not evacuated by producers following RTE's activities in its grid;
- follow-up of voltage waveform quality, which is a particularly important topic given the growing frequency of situations of high voltage in the transmission network, situations that may have a negative impact on the activity of certain grid users;
- follow-up of average costs and timeframes for grid connection.

However, RTE is not in favour of a financial incentive on the timeframe for meter repair interventions, unless the calculation of this indicator excludes elements that are not within its scope of responsibility. RTE is also opposed to the implementation of an indicator on the timeframes for installing/changing meters since it has not recorded any customer claims on this topic in several years. Lastly, RTE requests for the current indicator for compliance with the connection deadline contained in the technical and financial proposal to be eliminated, on the grounds that it includes external administrative timeframes over which RTE has no influence.

Regarding the first point, CRE considers that it will be difficult to provide a framework and audit this notion of the operator's "responsibility" within the calculation of the indicator as proposed by RTE, and decides to maintain the follow-up of the existing indicator for TURPE 6 HTB. On the matter of changing and installing meters, given the results presented by RTE, CRE decides not to establish the indicator envisaged initially. Lastly, CRE does not share RTE's position concerning the timeframes contained in the technical and financial proposal, and reiterates that this indicator remains relevant within the framework of following up grid connection timeframes.

Therefore, CRE adopts the 14 follow-up indicators below:

- Grid connections:
    - follow-up of compliance with the deadlines in the technical and financial proposal;
    - follow-up of compliance with the deadlines in the connection agreement;
    - follow-up of the differences between the costs in the connection agreement and actual costs;
    - follow-up of the differences between the costs in the technical and financial proposal and +/-15% of actual costs;
    - follow-up of average connection timeframes by segment (offshore wind, onshore renewable energy, distributors and customers);
- Metering:
    - follow-up of compliance with meter repair intervention deadlines;
- Claims:
    - follow-up of the rate of response within 10 days;
    - follow-up of the rate of claims processing within 30 days;
    - follow-up of the average overall duration for claims processing;
- Voltage waveform quality:
    - follow-up of the average duration of maximum voltage exceedance, by voltage level;
    - follow-up of the average frequency of voltage in the exceptional high end of the voltage range, by voltage level;
- Continuity of supply:
    - follow-up of compliance with contract commitments in the transmission grid access contract related to quality of electricity;
    - follow-up of compliance with work dates and durations planned by RTE in the public transmission grid for industrial clients;
    - follow-up of power not evacuated by producers due to RTE's activities on the public transmission grid.

Regarding the quality of voltage waveform, CRE introduces at this stage two new indicators for TURPE 6 HTB, but it may be relevant to supplement them with other indicators. CRE therefore requests RTE to initiate works within its "voltage ancillary services" working groups, in order to meet market participants' expectations on this matter.

In addition, RTE will also implement an online platform accessible to users to make works planning more transparent. After carrying out its work, RTE will send a questionnaire to its clients to measure their satisfaction regarding the planning of the works to assess any areas for improvements.

Lastly, CRE requests RTE to publish once a year, the above mentioned indicators on quality of service as well as the results of its satisfactions surveys. A recap of the results of the three previous years must also be presented. CRE also requests RTE to have CURTE discuss at least once a year the results of the indicators on quality of service in order to identify the main challenges of quality of service.

All of the components of the quality of service follow-up mechanism for TURPE 6 HTB are summarised in Annex 2.

2.4.2 Incentive regulation for quality of supply

2.4.2.1 Incentive regulation for quality of supply

Quality of supply is an essential counterpart to the tariffs paid by grid users. The incentive regulation for quality of supply aims at guaranteeing that the productivity gains made by RTE do not come at the expense of a drop in quality of supply. In that regard, CRE has established, since TURPE 3 HTB, incentives for the improvement of continuity of supply, and more specifically, on the average outage duration. This mechanism was renewed and reinforced in 2013 under TURPE 4 HTB, by extending the scope of the incentives to the average outage frequency. Since TURPE 5 HTB, it is based on a progressive linear incentive scheme.

For TURPE 5, the incentive for year *N* (in €million) is determined by the following formula:

$$I_Y = 17 \times (EOT_{ref} - EOT_N) + 109 \times (AOF_{ref} - AOF_N)$$

Where:

- EOT_N is the equivalent outage time, i.e. the average outage duration for the year, and corresponds to the ratio between power not distributed (excluding exceptional events[35]) and the average power supplied, expressed in MW ;
- AOF_N is the average outage frequency (long and short[36]) of year *N* and corresponds to the ratio between the number of long and short outages and the number of installations connected to the transmission grid;
- EOT_{ref} is the reference equivalent outage time, equal to 2.8 minutes/year;
- AOF_{ref} is the reference average outage frequency, equal to 0.46 outages/year.

The annual incentives applying to the equivalent outage time (EOT) and the average outage frequency (AOF) is based on a valuation of the non-distributed energy used for network planning. This valuation leads to an annual incentive on the EOT of €17 million per minute per user per year, and on the AOF, of €109 million per outage per user per year[37]. The amount of the incentive for a year *N* is capped at €45 million in order to limit the financial risk related to this regulation mechanism.

Noting that quality of supply has reached a satisfactory level[38] and is consistent with the grid sizing strategy envisaged by RTE in its TYNDP, CRE indicated in its public consultations of 17 October 2019 and 1 October 2020, its intention to stabilise for TURPE 6 HTB the quality of supply objectives set for RTE at the level of the objectives defined in TURPE 5 HTB. CRE therefore proposed making the incentive regulation asymmetrical as concerns the two indicators, keeping the targets defined in TURPE 5 HTB, in order to incentivise RTE to maintain the current quality of supply level without seeking to improve it over the next tariff period (which could cause overinvestments in the grid, not necessary for the collectivity). This asymmetrical regulation would consist in not paying RTE a bonus when it has beaten the EOT or AOF targets. Most participants are in favour of the establishment of an asymmetrical regulation, considering, like CRE, that it gives RTE an incentive to maintain the current quality of supply level and not to invest more than necessary.

RTE does not agree with this asymmetrical regulation mechanism. It does not share CRE's analysis according to which its investment decisions could be guided by the pursuit of "overperformance" in quality of supply so as to obtain bonuses through this regulation. Moreover, the goal of maintaining the current quality level, which is desirable and expressed in the TYNDP, would be best reached, according to RTE, by re-adopting the mechanism in effect in TURPE 5 HTB.

CRE highlights that simulations show that the risk of penalties obtained with the asymmetrical regulation mechanism and its configuration is limited, given in particular the possible counterbalancing between the results of the different indicators.

Therefore, the present deliberation introduces, for TURPE 6 HTB, an asymmetrical incentive regulation for the two quality of supply indicators, maintaining all of the parameters (targets, magnitude and cap on the incentive) which remain unchanged compared to TURPE 5 HTB:

- the reference equivalent outage time EOT_{ref} is equal to 2.8 minutes/year;

[35] Exceptional events are specifically described in the TURPE 5 HTB deliberation. They are in particular the atmospheric phenomena of an exceptional nature given their impact on the grids, characterised by an annual probability of incidence of less than 5% for the given geographical area once at least 100,000 end users supplied by the public transmission and/or distribution grids without electricity in one day and for the same reason.
[36] Short outages have a duration between 1 second and 3 minutes. Long outages have a duration higher than 3 minutes.
[37] This means, for example, that if each user has an outage once in the year, RTE receives a penalty of €109 million.
[38] Supply quality in the electricity transmission network has improved considerably over the last few decades. For example, the equivalent outage time went from an average 3.93 minutes per year during TURPE 4 to 2.62 minutes over the last three years of TURPE 5 HTB; the average outage frequency, went from 0.44 to 0.38. RTE's customer surveys show that grid users are generally satisfied.

- the reference average outage frequency AOF_{ref} is equal to 0.46 outages/year;
- the overall incentive amount for a year *N* (in €million) is given by:

$$I_N = \mathrm{Min}\big(17 \times \big(EOT_{ref} - EOT_N\big) + 109 \times \big(AOF_{ref} - AOF_N\big)\,;0\big)$$

- the cap on the incentive is set at €45 million/year.

2.4.2.2 Mechanism related to long outages in the public distribution grid resulting from the public transmission grid

For the TURPE 5 period, CRE introduced a mechanism making RTE bear the cost of the consequences of long outages in the public distribution grid due to the public transmission grid, by refunding distribution system operators (DSOs) the compensation made to their clients. TURPE 5 HTB provided for coverage of the reimbursement of this compensation based on a trajectory of €7.5 million/year, corresponding to the annual amount of compensation that RTE would have to pay, in expectancy, to the DSOs. In addition, to avoid exposing RTE to a very high financial risk, the amounts paid by RTE to the DSOs above a certain cap, set at €15 million/year for TURPE 5 HTB, are compensated through the CRCP.

In its tariff proposal, RTE stated that it was in favour of maintaining the mechanism since it made the operator accountable for all of the consequences of outages to the grid it manages. However, RTE proposed:

- on the one hand, lowering the level of the annual compensation amount covered by the tariff, in consistency with the amounts recorded and estimated by RTE over the TURPE 5 period (an average €2.5 million/year over the years 2018 and 2019, excluding the year 2017 considered as an exceptional year);
- and on the other hand, lowering the cap of €15 million/year to €5 million/year in order to have more coverage against weather events, which in its opinion, are responsible for most of the costs borne over the TURPE 5 period and for which RTE has no control.

Considering that RTE only has partial control of these costs in the case of high-impact weather events, CRE, in its public consultation of 1 October 2020, proposed lowering the trajectory of this item to €1.6 million/year, corresponding to the average compensation paid by RTE to the DSOs over the period from 1 August 2017 to 31 December 2019, and lowering the threshold for inclusion in the CRCP to €9 million/year, in order to maintain a risk level for RTE equivalent to that of TURPE 5 HTB.

A great majority of participants are in favour of this proposal. While RTE also agrees with the principle of the proposal, it however requested that the threshold for CRCP inclusion be set at €3.2 million/year, in order to balance the maximum level of penalties and that of bonuses, respectively -€7.4 million/year and +€1.6 million/year, with the mechanism envisaged.

CRE considers that lowering the threshold, from €15 million for TURPE 5 HTB to €9 million, as proposed in the consultation for TURPE 6 HTB, will further cover RTE from the consequences of extreme weather phenomena for the TURPE 6 period (compared to the past tariff period). CRE however decides to also use, in its assumptions, the compensation made or to be made by RTE for outages that occurred over the period from 1 January 2020 to 30 June 2020.

Therefore, the present deliberation implements the following mechanism for the TURPE 6 period:

- coverage by the tariff of €1.8 million/year of RTE's reimbursement to the DSOs, of the compensation paid by the latter to their clients in the case of long outages due to the transmission grid; and
- inclusion in the CRCP of the amounts paid by RTE to the DSOs above €9 million/year.

The components of CRE's mechanism for following the continuity of supply for TURPE 6 HTB are presented in annex 3.

2.5 Incentive regulation for R&D and innovation

In the context of a rapidly evolving energy sector, particularly that of electricity, CRE attaches specific importance to innovation, the development of smart grids and grid adaptation to the energy transition. System operators must have the necessary resources to successfully carry out their research and development (R&D) and innovation projects, which may require large information system budgets, essential for providing an efficient and high-quality service to network users, and to develop their network operations tools. In return, system operators must use these resources transparently and efficiently. More generally, they must develop their practices, and network and market access conditions as much as necessary to promote innovation by all electricity system actors.

Article 18 of regulation (EU) 2019/943 on the internal market in electricity provides for the pricing methods to give appropriate incentives, both in the short and long term, to the transmission system operators to support related research activities and facilitate innovation in the interest of users.

2.5.1 R&D regulation

In order to meet these requirements, the incentive regulation for R&D is currently based, for all operators on:

- a trajectory of R&D costs, with an asymmetrical incentive: at the end of the tariff period, the amounts not spent over the period are returned to users while the operators bear the costs over the established trajectories. This approach serves to not encourage the operator to reduce its R&D expenses;
- preparation of a detailed annual report to be sent to CRE, which assesses the R&D actions undertaken, supplemented by a bi-annual public report.

Over the first three years of the TURPE 5 period, RTE's R&D expenses totalled an average €33 million/year, a level comparable to the target trajectories set by CRE. Moreover, over the 2017-2019 period, RTE obtained €3.2 million in cumulated subsidies compared to the projected €4.5 million. RTE's R&D expenses were driven mainly by two subjects: "asset management", whose goal in particular is to anticipate installation renewal needs and improve the performance of grid maintenance, and grid "functioning and operation".

In its public consultations of 14 February 2019 and 1 October 2020, CRE proposed maintaining the R&D cost coverage terms so as to not encourage operators to arbitrate between savings on their R&D expenses and the preparation of the future, and to introduce the possibility of revising this trajectory midway into the tariff period. CRE also proposed increasing the transparency of the projects and associated expenses by requesting operators to consult the market at the start of the tariff period regarding the main research fields they intend to pursue. Most participants that answered the public consultations were in favour of the system proposed. Moreover, participants commended RTE's organisation of a consultation on its R&D topics at the start of the tariff period.

Given all of these elements and its own additional analyses, for the TURPE 6 HTB period, CRE sets up incentive regulation based on the following principles:

- the incentive mechanism for controlling RTE's R&D expenses is maintained. An R&D cost trajectory is defined with the possibility, if RTE submits a reasoned request to CRE, of revising this trajectory midway into the tariff period in order to afford the operator more latitude for adapting its programme. At the end of the TURPE 6 period, RTE will submit a financial assessment of its R&D to CRE. Any amounts not spent over the period will be returned to users through the CRCP, while the operator will bear any trajectory overruns;
- transparency and verification of the efficiency of R&D spending are reinforced through two exercises, with the format to be determined conjunctively between CRE, RTE and the other operators:
    - annual transmission to CRE of technical and financial information for all ongoing and completed projects, instead of the current report to CRE;
    - bi-annual publication by RTE of a report intended for the public, in line with the mechanism currently in place. The reports will have to be harmonised between the operators having an incentive regulation mechanism for R&D, in particular thanks to standardised indicators, and enhanced with concrete elements concerning the benefits of projects for network users, as well as systematic feedback on the demonstrator projects financed by the tariff;
- CRE requests RTE to consult the market and R&D ecosystem participants before the end of 2021 on the major research topics it plans to develop.

Lastly, RTE shall publish its R&D roadmap for the 2020-2030 decade at the end of Q1 2021 with a detailed focus on the actions that will be undertaken over the TURPE 6 period.

Trajectory of R&D expenses for TURPE 6

R&D expenses under TURPE 6 HTB are reduced by the amount of subsidies received. Therefore, if RTE obtains additional subsidies, they can be used to finance its R&D activities.

RTE presented, for the TURPE 6 period, the following R&D expenses trajectory:

Table 1 : RTE's forecast R&D expenses for TURPE 6 HTB (in €million nominal)

In nominal €million	2021	2022	2023	2024	Total 2021-2024
RTE proposal – R&D (gross)	38.9	39.8	40.3	41.4	160.4
Subsidies	1.1	1.1	1.2	1.2	4.5
RTE proposal – R&D (subsidies deducted)	**37.8**	**38.7**	**39.1**	**40.2**	**155.9**

This overall budget of €155.9 million for TURPE 6 represents a 15% increase compared to the overall trajectory of TURPE 5 HTB. RTE's ambitious programme for TURPE 6 is based on the five strategic R&D programmes in TURPE 5[39], which must make the transmission grid and power system more resilient against disruptive evolutions, while accompanying the energy, digital and societal transitions. The budget increase aims, in particular, to address the new challenges of the energy transition, digital transformation and the architecture of electricity markets. In addition, this increase is consistent with the recent recommendations of the International Energy Agency and the Intergovernmental Panel on Climate Change (IPCC) to increase national R&D budgets so as to support the energy transition. CRE therefore adopts this trajectory.

CRE will review, at the end of the tariff period, the sums actually spent by RTE and will return to users, through the CRCP, any difference between the projected and actual trajectory, if RTE has not spent the entire envelope.

2.5.2 Smart grid projects

A smart grid counter was introduced for electricity system operators since TURPE 5 HTB, enabling them, during the tariff period, to obtain additional funding. Therefore, RTE is authorised to request, once per year, coverage of operating expenses relating to the deployment of smart grid technologies not specified in the tariff deliberation, for projects representing at least €3 million, provided that it demonstrates that the cost of these projects will be more than compensated for by the savings they will generate for grid users in the long term. This mechanism responds to a need for flexibility for the fast rollout of innovative solutions that will be valuable in the long term for the community, as an alternative to infrastructure investments or postponements.

RTE did not make use of the smart grid mechanism over the 2017-2020 period. In its tariff proposal, the operator stated that, on the one hand, the €3 million threshold was too high for most of the projects that might be concerned, and that, on the other hand, many smart grid projects involved investment expenses (and not operating expenses) not eligible for the mechanism in effect under TURPE 5 HTB.

In its public consultations of 14 February 2019 and 1 October 2020, CRE proposed lowering the current threshold of the smart grid counter to €1 million for RTE for the next tariff period, in line with the threshold set for all gas operators, without modifying the scope of expenses and the eligible projects. Most participants that answered the public consultations were in favour of CRE's proposal. Some system operators however expressed reservations about the scope of expenses eligible for the mechanism, and requested for the coverage of additional expenses associated with certain IS investments to also be examined within the framework of the smart grid counter.

Given all of these elements and its additional analysis, CRE decides, for the TURPE 6 tariff period, to continue the principle of a smart grid counter. The eligibility threshold of this mechanism is set at €1 million. The operating expenses as well as the normative capital expenses associated with IS investments of an amount higher than this threshold are also eligible for this mechanism. The financial consequences of the implementation of this mechanism, such as the integration of any additional OPEX and normative capital expenses, will be taken into account in the CRCP.

2.5.3 Data publication

The provision by RTE of market data to market participants is of major importance for these participants, both from the point of view of data quality and of the operator's timeframes for publishing and transmitting the data. For TURPE 5 HTB, two indicators cover the publication of data:

[39] These five programmes are: Change in grid infrastructure; Asset management; Functioning and operation of the electricity system; Foresight, market and energy transition; Environment and society

- the monthly rate of availability of RTE's services portal, on which it publishes numerous market data. RTE's performance regarding this indicator was satisfactory over the 2017-2019 period, remaining above 99%;
- the rate of accuracy of the trend data of the balancing mechanism, whose values were also higher than 99% over the 2017-2019 period.

Despite this good performance, feedback from contributors to CRE's public consultation of 17 October 2019 showed that this did not respond to all of their needs. Participants identified priority data, especially in connection with the balancing mechanism and the capacity mechanism, for which the quality of data and compliance with data provision timeframes are critical.

CRE also considers that access to data is a priority topic, since these data are essential for improving the services provided to end clients and for innovation. With this in mind, and taking into account the needs expressed by participants, CRE proposed in its public consultation of 1 October 2020, to introduce follow-up indicators on compliance by RTE with deadlines for publication (or transmission) of data identified as a priority for participants (three pieces of data relating to the capacity mechanism[40] and one piece of data relating to the balancing mechanism[41]).

Most participants were in favour of this proposal by CRE. RTE however requested the exclusion from the calculation of these indicators deadlines that would depend on third parties (e.g. DSOs).

Moreover, additional exchanges took place between RTE and CRE, enabling a reassessment of the relevance of certain indicator proposals presented in the abovementioned public consultation and a better understanding of the proposals of certain participants.

Given all of these elements, CRE decides to follow, for TURPE 6 HTB, the following six indicators:

- the monthly rate of availability of RTE's services portal;
- the accuracy rate of the trend data of the balancing mechanism;
- the quality of the effective level of capacity and the level of estimated and definitive capacity obligations transmitted by RTE to the stakeholders concerned;
- the deadline for the publication by RTE of the declaration of the evolution of the certified capacity level[42] updated in the certified capacity register;
- the deadline for transmission by RTE of the certification contract to the capacity operator[43];
- the deadline for transmission by RTE of the verification of the order execution in the balancing mechanism. More precisely, RTE shall follow two additional monthly indicators to report on its performance regarding the deadline for transmitting its verification of the execution of the balancing order:
  - the first indicator will cover transmission by RTE of the verification of balancing order execution using data at RTE's disposal within contract deadlines[44];
  - the second indicator will cover the number of load curves received by RTE within contract deadlines from the DSOs, in relation to the number of sites connected to the public distribution grid taking part in the balancing mechanism, for injection and withdrawal (corresponding to the theoretical number of load curves that RTE should receive to perform verification of balancing order execution.) The data held by the DSOs on a week W (from Saturday to Friday) are expected contractually by RTE on Friday at noon of week W+1. The monthly indicator will thus reflect whether the load curves necessary for the verification of balancing order execution by RTE have been made available to the operator within the deadlines.

CRE requests RTE to publish, once per year, all of the indicators followed. For each publication, the results of the three previous years shall be recapped with regard to indicators for which such a record exists.

In addition, if specific needs are reported by market participants or identified by CRE at a later time, CRE reserves the possibility of updating the list of priority data and introducing an incentive for the publication of such data. In that case, this update will be done in coordination with RTE and brought to the knowledge of all participants.

[40] These are i) the certification and capacity obligation parameters specified in the rules ii) the declaration of the evolution of the informative parameters for producer certification and iii) the levels of updated certified capacity published by RTE in the register.
[41] This is the verification of the execution of orders in the balancing mechanism.
[42] The deadline in the capacity mechanism rules is 5 working days after this declaration at the latest (section 7.6.1.4)
[43] The deadline in the capacity mechanism rules is, at the latest, 15 working days after the date of receipt by RTE of the certification request of the capacity operator (section 7.5.1.5 for capacity operators connected to the public distribution grids and section 7.5.2.1 for capacity operators connected to the transmission network).
[44] The deadline in the balancing rules is Friday between the 14th and 20th day of month M+1 (section 4.6.1.3.3.1).

The incentive will be addressed in accordance with the framework defined in section 2.5.4 “Promote external innovation” of the present deliberation.

2.5.4 Promote external innovation

In the context of energy transition, during its different deliberations and thematic reports, CRE formulated a certain number of requests to system operators regarding the establishment of developments to facilitate innovative uses in their networks and therefore ensure the successful achievement of the missions assigned to them by law and regulations. However, system operators’ deadlines for implementing certain new actions required by legislative and regulatory texts or requested by CRE are not always satisfactory and are sometimes incompatible with the pace of innovations. CRE considers that the implementation of these actions in a timely manner is essential in a context marked by rapid transformations in the power system and its uses.

On that basis, CRE proposed in its public consultations of 17 October 2019 and 1 October 2020, to establish an incentive regulation for compliance by RTE of deadlines for carrying out actions identified as priorities to promote innovation pursued by market stakeholders. Four priority actions were presented during the public consultation of 1 October 2020, in connection with the proposals expressed previously by market participants, and associated with implementation deadlines defined by CRE in line with regulations or after consulting with RTE:

- implementation of a tender for the constitution of the automatic frequency restoration reserve, as at 1 October 2021;
- publication of the map of all congestion in France, as at 1 January 2023;
- implementation of an IS tool to correct balancing perimeters for local flexibility sources, as at 1 March 2023;
- implementation of a contractual framework for flexibility sources taking part in congestion management, as at 1 October 2024.

A large majority of participants are in favour of the mechanism presented by CRE. No participant identified any other priority actions, but a few requested a more rapid implementation of certain actions.

However, RTE is not in favour of the mechanism, considering that it does not have the financial and human resources to meet the objectives presented by CRE in its public consultation. RTE also wishes for CRE to take into account the COVID-19 crisis when setting deadlines (potential delays external to RTE). Moreover, the operator expressed its disagreement with the date set for the publication of the map of congestion, reiterating that as at 01/01/2023, only eight regional renewable energy grid integration plans (S3REnR) will have been revised, which will not make it possible to publish a map of all congestion in France. RTE states that these congestion maps are prepared, for each region, within a maximum timeframe of six months following the publication of the revised regional plan, and that this timeframe should be the target of the goal set by CRE.

CRE shares RTE’s view of the relevance of taking into account the revised regional plans to prepare a map on the location of congestion relating to production, and understands the maximum operating timeframe to which RTE can commit. However, the publication of a map of congestion does not require taking into account the revision of the regional plans if that revision is not scheduled in the near future. Therefore, CRE requests RTE to publish the map of congestion, including for regions whose regional plan revision is far off and without waiting for that revision, in order to respond to market participants’ need to have that map as soon as possible.

Given all of the elements, TURPE 6 HTB sets an incentive regulation mechanism for compliance by RTE of deadlines for implementing actions identified as “priorities”, which is based on:

- a reduced list of priority actions to be included in the mechanism: in order to be able to respond quickly to innovation, the list of priority actions may be updated during the TURPE 6 period in line with legislative and regulatory developments and priority work identified by CRE, and after consultation of market participants. Priority actions may relate, in particular, to integration of flexibility and to balancing mechanisms and would respond, for example, to the following issues: implementation of European platforms, participation of batteries and other flexibility sources in market mechanisms, etc. ;
- for each of these actions, an implementation deadline is associated, based on legislative and regulatory texts when the action is required by these texts, or established in coordination with the operators when the actions are connected with work deemed a priority by CRE. The list of priority projects identified to date as well as their implementation deadlines are indicated below:
    - implementation of a tender for the constitution of the automatic frequency restoration reserve, as at 1 October 2021;

    - publication of a framework agreement for storage and load shedding flexibility taking part in congestion management, as at 1 January 2022;
    - publication of a map of congestion across the entire French public transmission grid as at 1 January 2023 at the latest, then an update of the congestion map of each region upon the revision of its regional plan for the connection of renewable energy to the grid, within a maximum timeframe of six months following the publication of each revised regional plan;
    - implementation of an IS tool to correct balancing perimeters when local flexibility is activated, operational as at 1 March 2023;
- non-implementation of these priority actions within the deadlines, in that it constitutes an obstacle to efficient access to the networks or to the proper functioning of the market, leads to the attribution of a penalty. Calculated monthly, the amount of this penalty is progressive, in order to penalise major delays more heavily. The amounts are as follows:
    - for a project implemented within 6 months following the date set by CRE, a penalty of €100 k/month of delay is applied;
    - for a project implemented within 6 to 12 months following the date set by CRE, the penalty is increased to €200 k/month of delay for the months above the sixth month;
    - for a project implemented later than 12 months following the date set by CRE, the penalty is increased to €400 k/month of delay for the months above the twelfth month;
- the overall amount of all of the penalties applied to RTE is capped at €10 million/year.

3. LEVEL OF EXPENSES TO BE COVERED AND TRAJECTORY OF THE TARIFFS FOR THE USE OF THE PUBLIC ELECTRICITY TRANSMISSION GRIDS

3.1 Level of expenses to be covered

3.1.1 RTE's tariff proposal

RTE supports the need for a major increase in investments over the TURPE 6 period, in order to enable connection of electricity generation from renewable energy, the renewal of its assets, the maintenance of a high level of quality of supply and the development and modernisation of its information system: investments would therefore increase from an average €1.5 billion/year over the TURPE 5 period to an average €2.2 billion/year over the TURPE 6 period.

This growth in investments would lead to a 23% increase in the RAB between 2019 and 2024. The impact of this increase in the RAB on the tariff is partly offset by a drop in the operator's financing costs. In its proposal, RTE requests that its WACC be set at 5.35% nominal before tax (instead of 6.125% during TURPE 5 HTB) and thus foresees a decrease in capital expenses of about 0.5% between 2019 and 2021 followed by an average increase of 4.7% per year over the 2021-2024 period.

RTE also proposed an increase in its net OPEX of roughly +15% between 2019 and 2021, followed by an average increase of +1.8% per year between 2021 and 2024[45].

RTE thus requests a total of expenses to be covered, net of interconnection revenue, of €4,511 million[46] in 2021, i.e. +€446 million (+11.0%) more than the expenses recorded in 2019, followed by an average increase of +3.7% per year. Given the drop in withdrawals anticipated by RTE on its grid, this increase would result in an average tariff increase of +6.25% per year over the entire TURPE 6 period.

Tariff impacts of COVID-19

The tariff proposal submitted by RTE to CRE was initially based on an electricity balance taking into account actual amounts from January to May 2020 and an assumption of a drop in volumes withdrawn in the second half of 2020, partly related to the COVID-19 crisis. This evolution affects the forecast transmission revenues for the year 2020 and therefore the CRCP balance as at 31 December 2020.

Secondly, RTE estimated the downward effect of the anticipated consequences of the COVID-19 crisis on the energy volumes injected into and withdrawn from its network for the TURPE 6 period. It expects a return to normal in 2024 and this affects the level of certain expense items and that of its tariff revenues. The other repercussions of the COVID-19 crisis on RTE's activities, its expenses and revenues trajectories, and the achievement of the objectives set by the incentive regulation in effect are difficult to quantify by the operator as at the date of publication of the present deliberation, whether it be for the year 2020 or the years 2021 to 2024. However, at this stage, RTE does not anticipate any major impact in its activities for the 2021-2024 period justifying a change in the expenses trajectories of its tariff proposal.

CRE wishes to conduct an analysis, cutting across all operators, of the impacts of this health crisis on all of their activity, in terms of operating expenses, trajectory and cost of investments but also quality of service. For that purpose, it will conduct a specific exercise in Q1 2021. If regulatory changes were to be envisaged within this framework, they will be addressed in a public consultation.

3.1.2 Operating expenses

3.1.2.1 Approach adopted by CRE

The objective of the incentive regulation of net operating expenses is, by allowing operators to keep the differences between the actual trajectory and the tariff trajectory, to improve their efficiency over the tariff period. The efficiency level revealed during the TURPE 5 tariff period must be taken into account to establish the TURPE 6 HTB, so that grid users benefit from these productivity gains over time.

For these reasons, CRE requested RTE to submit its tariff proposal in the light of the latest actual figures, justifying any significant deviation compared to the actual 2019 figure.

[45] Including inflation assumption
[46] Excluding CRCP reconciliation

CRE commissioned Schwartz & Co to audit RTE's net operating expenses (excluding purchases related to electricity system operation). Work was conducted between May and September 2020. The auditor's report, based on RTE's updated proposal, was published together with the public consultation of 1 October 2020.

This audit provided CRE with a good understanding of RTE's operating expenses and revenues as well as its "non-grid" investments over the TURPE 5 period. It also thoroughly analysed the forecast operating expenses and "non-grid" investments presented by the operator for the upcoming tariff period (2021-2024). More precisely, this audit enabled:

- to provide expertise on the relevance and justification of the operator's net operating expenses trajectory for the next tariff period;
- to assess the level of actual expenses (2017-2019) and forecast expenses (2021-2024);
- to formulate recommendations about the efficient level of net operating expenses to be taken into account for TURPE 6.

The conclusions of the audit report gave rise to a debate with RTE as from July 2020. RTE was therefore able to comment on the results of the auditor's work.

In its public consultation of 1 October 2020, CRE had considered a range with the "high end" being the trajectory of net operating expenses as proposed by RTE, and the "low end" being the trajectory recommended by the consultant, to which it had added its own preliminary analyses regarding the purchases relating to electricity system operation.

Following the public consultation, discussions continued between RTE and CRE on a certain number of net operating expense items. The level finally adopted by CRE is the result of these exchanges with the RTE and its own analyses.

3.1.2.2 Inflation trajectory

CRE's and the auditor's analyses concerned the tariff proposal submitted by RTE.

However, in compliance with what it stated in its public consultation of 1 October 2020, CRE adjusted the inflation assumption for the years 2020 and 2021 based on the draft finance law for the year 2021, and based on the latest IMF estimates for the years 2022 to 2024. All of the trajectories presented below are corrected for this new inflation trajectory.

Table 2 : Inflation trajectory adopted in RTE's tariff proposal and in the present deliberation

	2020	2021	2022	2023	2024
Forecast inflation adopted in RTE's tariff proposal	0.4%	1.40%	1.60%	1.70%	1.70%
Forecast inflation adopted in the deliberation	0.2%	0.6%	1.0%	1.2%	1.5%

Moreover, the amount of net operating expenses subject to an incentive adopted in the calculation of the definitive allowed revenue takes into account the difference between the forecast inflation adopted in the present deliberation and actual inflation.

3.1.2.3 Purchases related to electricity system operation

3.1.2.3.1 RTE's proposal

With regard to purchases related to electricity system operation, RTE's proposal totals an average €1,036 million/year over the TURPE 6 period. RTE's proposal would lead to an increase in these expenses of +€184 million in 2021 compared to actual expenses in 2019, i.e. a +22% increase.

The forecast purchases relating to electricity system operation presented by RTE in its tariff proposal for the TURPE 6 period are presented in the table below:

Table 3 : RTE's proposal - purchases relating to electricity system operation (in €million$_{nominal}$)

In€million$_{nominal}$	2019 Actual	2021	2022	2023	2024	TURPE 6 HTB average
Purchases for loss compensation	423	555	542	538	543	545
Purchases for ancillary services and balancing reserves	304	346	343	342	346	344
of which frequency/balancing control	*196*	*238*	*235*	*232*	*234*	*235*
of which voltage control	*108*	*108*	*108*	*109*	*112*	*109*
Congestion expenses	10	26	37	50	62	44
TSO exchange agreements	-1	0	0	0	0	0
ITC[47]	22	21	21	21	21	21
Imbalance settlement account balance[48]	11	0	0	0	0	0
Capacity mechanism balance	0	0	0	0	0	0
Interruptibility	79	83	83	83	83	83
Total	**848**	**1,031**	**1,026**	**1,033**	**1,055**	**1,036**

The main factors of the increase requested by RTE are:

- a significant increase in the energy and capacity purchase cost for loss compensation (+€122 million between 2019 and the 2021-2024 average, i.e. +29%) essentially driven by an increase in energy and capacity prices, and to a lesser extent, by a higher forecast average volume of losses;
- an increase in the cost of purchases relating to ancillary services and balancing reserves (+€40 million between 2019 and the 2021-2024 average, i.e. +13%), due in particular, according to RTE, to the implementation of expected changes in the balancing reserve markets as of 2021 (contracting modes, implementation of the European platforms, introduction of new products such as "frequency" products and the downward manual frequency restoration reserve, etc.). In particular, with regard to the automatic frequency restoration reserve, RTE considers it will have to revise upward its sizing concurrently with the switch to the tender procurement and believes that this change could increase the cost;
- an increase in the cost of congestion (+€34 million between 2019 and the 2021-2024 average, i.e. +342%, this increase breaking down into +€15 million for national congestion and +€19 million for international congestion). RTE states that this anticipated increase is due to the implementation of generation curtailment in the national grid and the evolution in methodologies for sharing international congestion costs among transmission system operators at European level.

3.1.2.3.2 CRE's analysis

Following its analyses, CRE adopts the trajectories presented in the following sections, leading to purchases for electricity system operation totalling an average €965 million/year over TURPE 6 HTB, i.e. an adjustment of -€81 million/year (-8%) compared to RTE's proposal. This trajectory corresponds to an average increase of +€108 million,

[47] Inter-TSO compensation, which aims to compensate each TSO for the costs generated by cross-border flows in their network.

[48] This is an account recording all of the financial flows related to RTE's activations in the balancing mechanism. The balance is rebilled to balance responsible parties through the *ex post* correction of the k factor within the framework of imbalance settlements, thus balancing the account.

i.e. 13% compared to the value observed in 2019. This trajectory remains upward compared to TURPE 5 HTB because of the increase in market prices affecting the cost of loss purchases, and the anticipated increase in congestion, in compliance with the TYNDP projections.

Loss purchases (item in CRCP subject to an *ad hoc* incentive regulation – see section 2.3.1.3)

The purchase trajectory for loss compensation presented by RTE in its tariff proposal was reassessed at the end of October 2020 by the operator to incorporate the most recent data for its energy and capacity market price forecasts, as well as actual costs of purchases already made for loss compensation. This update leads RTE to propose an average €540 million/year for the TURPE 6 period (compared to €545 million/year in its tariff proposal).

RTE based its proposal on the market prices published in October 2020 for calendar baseload products covering the delivery years in question. They total an average €45.2/MWh for quotes covering the TURPE 6 period, compared to an average €36.7/MWh for the calendar baseload products for the years 2017-2019 at the time TURPE 5 HTB was prepared. For capacity, the price assumptions adopted by RTE are based on the result of auctions held in October 2020 and covering the delivery years 2021 and 2022. In these auctions, capacity prices ranged between €18 k/MW/year and €33 k/MW/year, compared to capacity prices ranging between €0 and €19 k/MW/year for 2019 and below €10 k/MW/year for 2017 and 2018.

In addition, RTE forecasts an increase in its loss volumes, particularly in connection with the update of its forecasts concerning the commissioning of certain projects over the TURPE 6 period, and with regard to interconnection projects in particular. RTE proposes an average loss rate applied to the forecast total injection volumes in the transmission grid of 2.25%.

CRE considers that the price assumptions adopted by RTE are relevant. However, concerning the volumes, CRE adopts a reference loss rate of 2.20%. CRE considers (see section 2.3.1.3.) that the loss rate must be based on the most recent loss rates observed and not on forecasts. RTE based its forecasts on assumptions deemed too uncertain by CRE (timeline for commissioning of some grid interconnections and impact of other investments that will come into operation and may reduce losses in particular).

The impact of this adjustment is an average -€13 million/year (i.e. -2% compared to RTE's proposal). The trajectory adopted by CRE for this item is therefore an average €527 million/year.

The trajectory of loss volumes associated with the trajectory of purchases for loss compensation adopted by CRE is as follows:

Table 4 : Forecast for reference loss volumes

In TWh	2021	2022	2023	2024
Forecast for reference loss volumes	10.9	10.9	11.0	11.2

Purchases related to frequency ancillary services and balancing reserves (item partly covered in CRCP – see section 2.3.1.4)

CRE adopts an adjustment of -€36 million/year, i.e. -16% compared to RTE's proposal. The assumptions adopted by CRE as well as their impact in terms of adjustments are presented below for each type of reserve:

- frequency containment reserve: keeping the current prices for the year 2021, in connection with the postponement of the implementation of the new terms for the certification of hydraulic capacity to 1 January 2022 (-€13 million only for year 2021);
- automatic frequency restoration reserve: non-inclusion of the increase in volumes envisaged by RTE, since the work relating to the development of the sizing method and the associated consultation are still in progress (CRE therefore did not take a position on the relevance of this development and the matter will only be put before CRE in spring 2021), and the modification of the contracting price for this reserve in accordance with the timeline for tender implementation(-€29 million/year);
- manual frequency restoration and replacement reserves: consideration of the results of the call for tenders for the year 2021 (+€5 million only for the year 2021);
- additional costs related to reconstitution of margins: inclusion of the costs observed over the TURPE 5 period (-€5 million/year);
- additional costs related to reconstitution of ancillary services: inclusion, on the one hand, of the costs observed over the TURPE 5 period (-€2 million/year), and on the other hand, the additional costs related

to the postponement of the implementation of the new terms for certifying hydraulic capacity participating in the frequency containment reserve (+€35 million only in 2021).

The trajectory adopted by CRE for this item is therefore €218 million in 2021 and an average €199 million/year over the TURPE 6 period.

CRE also reiterates that this trajectory will be reassessed each year in accordance with the regulatory framework defined for the TURPE 6 period (see section 2.3.1.4).

Purchases related to voltage ancillary services (item not in the CRCP, with a 100% incentive)

The trajectory of purchases related to voltage ancillary services presented by RTE in its tariff proposal was reassessed in November 2020 by the operator to take into account the anticipated increase in the remuneration of the synchronous compensation service offered by hydraulic units. This update leads RTE to propose an average €112 million/year for the TURPE 6 period (compared to €109 million/year in its tariff proposal).

The adjustments adopted by CRE for this item incorporate the most recent information available on the forecast evolution of the power generation capacity for voltage control and on the values of the indexes defined in the rules and used for the price calculation, as well as an adjustment of the remuneration of the synchronous compensation service offered by hydraulic units. These adjustments represent a drop of -€3 million/year compared to RTE's last trajectory. The trajectory adopted by CRE for this item is therefore an average €108 million/year.

The purchases related to the voltage ancillary services item is not included within the scope of the CRCP and therefore has a 100% incentive. However, RTE forecasts a major change in the rules relating to voltage ancillary services over the TURPE 6 period. These new rules will depend on work in progress and a consultation with grid users; their consequences on the tariff trajectory are still uncertain. Therefore, the trajectory of this item can be revised during the tariff period in the case of a development in the rules having major consequences on the trajectory.

Congestion expenses (item partly covered in the CRCP – see section 2.3.1.5.)

In its tariff proposal, RTE presents a significant increase in expenses related to national and international congestion bringing them to an average€44 million/year (€10 million in 2019).

RTE states that the increase in national congestion expenses (an average €26 million/year compared to an average €7.7 million/year over 2017-2019) is due mainly to the increase in generation curtailment as part of the optimal sizing planned in the TYNDP, and to a lesser extent, "historical" congestion occurring in the large transmission network.

The increase proposed by RTE however corresponds to an average generation curtailment cost assumption not representative of the growing share of wind power under contract for difference support scheme (versus purchase obligation) for 2025, and a trajectory of "historical" congestions occurring in the national transmission network not based on the past average. CRE therefore corrected this trajectory and as a result adopts an adjustment of an average -€11 million/year for national congestion costs (i.e. -43% compared to RTE's proposal).

The increase in international congestion expenses (an average €18 million/year versus an average €4 million over 2017-2019) is due, according to the operator, to the increase in redispatching and countertrading costs it will bear, particularly in connection with the modification expected in the method of allocating costs at the borders of North Italy and the France-Spain border. CRE adopts RTE's assumptions on this matter.

Therefore, the trajectory adopted for TURPE 6 HTB totals an average €33 million/year, which remains three times higher than the average congestion costs borne by RTE in 2019.

Interruptibility[49] (item 100% covered in CRCP)

The trajectory presented by RTE in its tariff proposal totals an average €83 million/year, corresponding to the average tender amounts, excluding reductions, between 2017 and 2020. This item is fully covered in the CRCP.

On the suggestion of RTE, CRE also took into account the average allowances in 2017 and in 2019[50], leading to a trajectory of €74 million/year over the TURPE 6 period (-€9 million/year compared to the average proposed by RTE).

Expenses related to interTSO compensation (ITC) (item not included in the CRCP, with a 100% incentive)

In its calculation for TURPE 6, RTE used the average export balance over 2012-2019 excluding the years 2016 and 2017, to calculate the forecast compensation costs. RTE considers that for the years 2016 and 2017, the French

[49] Through this interruptibility mechanism, RTE may suspend, in less than 5 or 30 seconds, one or several industrial consumers connected to the electricity transmission grid who have been selected through calls for tenders and are paid by RTE for this service.
[50] CRE does not adopt, in its analyses, the allowances observed in 2018 given their exceptional nature.

export balance was exceptionally low, because of the unavailability of nuclear power generation, and that these years were therefore not representative of the trend.

CRE does not adopt this re-processing requested by RTE and therefore adjusts its proposal by an average -€6 million over the TURPE 6 period based on the average ITC costs observed over 2017-2019, in line with the methodology used for most cost items. The trajectory adopted by CRE for this item is therefore an average €15 million/year.

Exchange contracts between TSO (item covered 100% in the CRCP)

CRE adopts a trajectory at -€0.2 million/year, corresponding to the average expenses and revenues associated with mutual assistance observed over the 2017-2019 period.

Balance of the imbalance settlement account (item not included in CRCP, with a 100% incentive)

CRE adopts RTE's trajectory. This is set at zero since the imbalance settlement account is designed to even out imbalances and therefore has no impact on TURPE.

Capacity mechanism balance (item covered 100% in the CRCP)

CRE adopts RTE's trajectory.

Summary

The trajectories set by CRE for purchases related to electricity system operation over the TURPE 6 period are presented in the following table:

Table 5 : RTE's net purchases for electricity system operation over the TURPE 6 period (in €million$_{nominal}$)

In € m$_{nominal}$	2019 Actual	2021	2022	2023	2024	TURPE 6 average
RTE's proposal		1,031	1,026	1,033	1,055	1,036
Adjustments adopted by CRE		-51	-89	-91	-91	-80
Trajectory adopted by CRE	**848**	**980**	**937**	**942**	**964**	**956**
Purchases for loss compensation	423	544	518	517	530	527
Purchases for ancillary services and balancing reserves	304	325	301	300	303	307
of which frequency/balancing control	196	*218*	*194*	*191*	*192*	199
of which voltage control	108	*107*	*107*	*109*	*111*	108
Congestion expenses	10	22	29	37	42	33
TSO exchange agreements	-1	-0.2	-0.2	-0.2	-0.2	-0.2
ITC	22	15	15	15	15	15
Imbalance settlement account balance	11	0	0	0	0	0
Capacity mechanism balance	0	0	0	0	0	0
Interruptibility	79	74	74	74	74	74

Therefore, the trajectory set by CRE forecasts a +16% increase in RTE's purchases related to electricity system operation between 2019 and 2021. These net operating expenses then progress by an average -0.6% per year over the 2021-2024 period.

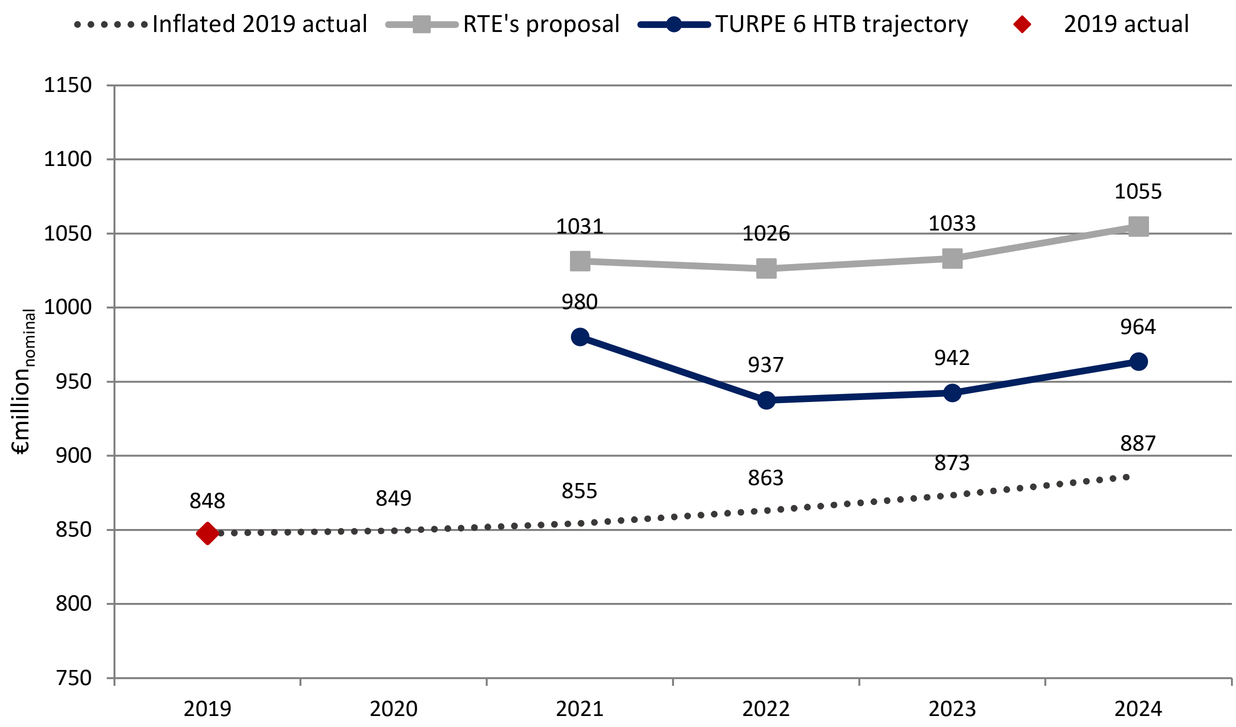

Figure 2 : RTE's net purchases relating to electricity system operation (in €million nominal)

3.1.2.4 Net operating expenses excluding purchases related to electricity system operation

3.1.2.4.1 RTE's proposal

RTE's proposal totals an average €2,166/year. The net OPEX excluding purchases related to electricity system operation would increase in 2021 by +€231 million, i.e. +12.4% compared to 2019 actual expenses. Expenses would then increase over the 2021-2024 period by an average +2.4% per year.

The forecast net operating expenses excluding purchases related to electricity system operation presented by RTE for the TURPE 6 period are presented in the table below:

Table 6 : RTE's proposal – Net OPEX excluding purchases relating to electricity system operation (in €million$_{nominal}$)

In €million$_{nominal}$	2019 Actual	2021	2022	2023	2024	TURPE 6 average
RTE's proposal – Net OPEX (excluding purchases relating to electricity system operation)	1,858	2,089	2,138	2,196	2,242	2,166
Evolution (%)		*+12.4%*	*+2.3%*	*+2.7%*	*+2.1%*	
of which Purchases of equipment and services	635	790	803	817	834	811
of which Asset management	*265*	*317*	*332*	*337*	*345*	*333*
of which Staff expenses	904	974	1,005	1,035	1,055	1,017
of which Taxes	545	585	606	627	652	617
of which Other operating expenses	92	97	99	100	100	99
of which Other operating revenues	-318	-356	-374	-383	-399	-378

The main items explaining RTE's proposal for 2019-2021 are as follows:

- "purchases of equipment and services": an increase of +€154 million between 2019 and 2021, i.e. +24.3%, with an increase in particular of +€52 million for asset management, and +€16 million for information systems. On the one hand, the increase in investments is accompanied, according to RTE, by an increase in net operating expenses, both related to maintenance of new installations such as offshore connections, and to the adaptation of engineering needs and corporate functions. On the other hand, RTE's asset management policy, which aims to seek optimal solutions for assets' life cycles enabling the optimisation of operating and investment expenses, accelerates spending on grid repair and maintenance (in particular for pylon painting, replacing disconnectors and insulators and installation of overhead lines). This acceleration is due to both the increase in the volume of operations to be performed and the increase in the unit cost of these operations. For information systems, RTE anticipates an increase in the cost of licences, a growth in the number of applications and new cybersecurity requirements;
- "staff expenses": a +€70 million increase between 2019 and 2021, i.e. +7.7%, particularly in connection with the increase in staff;
- "taxes": a +€40 million increase between 2019 and 2021, i.e. +7.3%, mainly a result of the increase in the sub-item "Pylon tax" because of the assumption of an increase in the unit tax on pylons;
- "other operating revenues": a +€37 million increase between 2019 and 2021, i.e. +11.8%, primarily in connection with the anticipated increase in capitalised production, which itself is linked to the increase in investments.

The impact of the COVID-19 crisis is estimated by RTE at €19.7 million in additional costs over the entire TURPE 6 period, concentrated over the year 2021 [confidential].

3.1.2.4.2 CRE's analysis

The auditor's analysis covered the updated tariff proposal submitted by RTE on 15 July 2020. Following its work, the auditor recommended an overall downward adjustment of the trajectory of net operating expenses (excluding purchases related to electricity system operation) by an average -€155 million per year (i.e. -7.2%).

Table 7 : Auditor's proposal – Net OPEX excluding purchases relating to electricity system operation (in €million$_{nominal}$)

In €million$_{nominal}$	2021	2022	2023	2024	TURPE 6 average
RTE's tariff proposal	2,089	2,138	2,196	2,242	2,166
Actual costs 2019 (inflated)	1,873	1,891	1,914	1,943	1,905
Adjusted auditor trajectory	**2,006**	**2,012**	**2,006**	**2,018**	**2,011**
Difference compared to RTE's proposal	-83	-126	-189	-224	-155

The main adjustments recommended by the auditor cover the "Asset management", "Information system", "Staff expenses" and "Taxes" items.

CRE, as part of the work carried out since the public consultation of 1 October 2020, has made a certain number of adjustments to the trajectory proposed by the auditor. The main adjustments CRE adopts compared to RTE's proposal are presented below.

Drop in production taxes:

The draft finance law (DFL) for 2021 plans for a drop in production taxes, particularly on the regional levies and property taxes.

The present deliberation takes into account the associated reductions in expenses for RTE.

Given the timetables for the publication of the DFL and of its public consultation, CRE had not included this evolution in the low end of the range presented in the public consultation. This adjustment is therefore added to those presented in the public consultation.

Table 8 : Auditor's proposal – Net OPEX excluding purchases relating to electricity system operation incorporating the impact of the 2021 DFL (in €million$_{nominal}$)

In €million$_{nomianl}$	Actual 2019	2021	2022	2023	2024
RTE's proposal	1,858	2,089	2,138	2,196	2,242
Adjusted auditor trajectory		**2,006**	**2,012**	**2,006**	**2,018**
2021 DFL impact		-65	-68	-71	-74
Adjusted auditor trajectory incl. 2021 DFL impact		**1,941**	**1,944**	**1,935**	**1,944**

Asset management:

The auditor proposes a downward adjustment of -€39 million/year in the envelope devoted to asset management (-11.8% compared to RTE's proposal of an average €333 million/year). The auditor maintained most of RTE's volume assumptions in line with the doctrine validated by CRE within the framework of its examination of the TYNDP. It however proposes adjusting the trajectory of this item by revising downwards the unit costs proposed by RTE, in particular those of the sub-items "Routine maintenance", "Recurring maintenance policies" and "Rehabilitation and replacement policies". Lastly, the auditor observed that the unit costs adopted by RTE are much higher than the unit costs observed in 2019 indexed to inflation.

CRE's analysis

CRE shares the auditor's overall approach which mostly adopted the activity volume assumptions presented by RTE concerning asset management, since this policy is aimed at better medium-/long-term optimisation between operating expenses and investment expenses. However, CRE considers that the OPEX increase granted must necessarily be accompanied by a regulatory framework protecting users in the event of non-execution of work and activities projected by RTE in its tariff proposal, and it therefore established in that regard a specific regulation mechanism (see section 2.3.1.2).

With regard to unit cost assumptions, CRE also shares the auditor's general analysis, but made several adjustments, particularly regarding tree trimming and corrective policies. Moreover, RTE provided additional justifications for hygiene measures, maintenance of conversion stations, management of national security and operating stocks and securing power substations. Therefore, CRE adopts RTE's proposals concerning these items.

With regard to the unit costs for pylon painting and rehabilitation of power transformers, RTE did not provide sufficient quantitative justifications to explain the anticipated major increase in these unit costs. However, the changes in practices planned by RTE could effectively lead to unit cost increases higher than those retained. Therefore, CRE decides to integrate the price effect of the unit costs of these specific sub-items in the CRCP, at a level of 50%., Thus, 50% of the difference with the reference unit costs, defined in the confidential annex 6, and applied to the work volumes performed by RTE will be covered in the CRCP.

CRE adopts an average adjustment of €29 million/year compared to RTE's proposal and thus sets the average trajectory for the "asset management" item at €303 million/year over the TURPE 6 period.

Information systems:

The auditor proposes a downward adjustment of an average -€5 million/year of the trajectory of operating expenses associated with information systems (-€3.6% compared to RTE's proposal). The auditor essentially suggests using the level observed in 2019[51] indexed to inflation or to the average growth rates observed over the last few years. The adjustment recommended by the auditor mainly covers two sub-items:

- licences: the auditor performed a new calculation of the trajectory using the same assumptions as RTE and obtained a trajectory lower by -€2 million/year;
- Administration, Operation, Maintenance[52]: the auditor does not adopt any increases in this item compared to the level observed in 2019 since RTE did not sufficiently justify this increase in its forecast trajectory.

CRE's analysis

CRE shares the auditor's global approach regarding the IS operating expenses item. In particular, CRE adopts:

- the entire adjustment covering the cost of licences;
- part of RTE's trajectory concerning administration, operation, maintenance expenses; for the part of the increase which the operator effectively justifies by the arrival of new data centres, the commissioning of which will generate additional expenses for this item over the TURPE 6 period.

CRE also adopts two additional adjustments:

- exclusion of the operating expenses related to the Hermès project excluding INUIT (-€1 million/year), since this project has not been approved by CRE, like all fiberizing projects[53];
- incorporation of the OPEX savings generated by the INUIT project (see section 3.1.3.2), in line with the assessment made by RTE in the project's economic review (an average -€2 million/year).

Therefore, for this information system operating expense item, CRE adopts an average adjustment of -€6 million/year leading to an average trajectory of €135 million/year for the TURPE 6 period.

Staff expenses:

The auditor proposes a downward adjustment of -€22 million/year in the envelope devoted to staff expenses (-2.2% compared to RTE's proposal).

The adjustment proposed by the auditor covers mainly the sub-item "Permanent staff" and results from:

- the downward revision in the growth of staff proposed by RTE. The auditor proposes to index the growth in staff to the increase in assets and/or the volumes of maintenance actions;
- the downward adjustment of NMW[54] and the age and job-skill coefficient[55] based on the historical averages observed, in coherence with what it recommends for Enedis;

[51] The operating expenses associated with information systems recorded during the years 2017, 2018 and 2019 are €118 million, €118 million and €125 million respectively.
[52] These are costs for the leasing of materials, software and hardware maintenance and labour expenses for the surveillance of applications and servers.
[53] In CRE's deliberation of 20 December 2018 approving RTE's investment programme for the year 2019
[54] NMW: national minimum wage. The evolution of this index, which is the essential parameter of the main part of remuneration, is determined within the framework of branch negotiations with employer associations and trade unions.
[55] This index reflects the change in the average cost of RTE's workforce.

- the downward revision of assumptions of incentives and retirement contributions based on the average observed between 2017 and 2019, excluding exceptional incentives;
- the downward revision of additional remuneration assumptions, in particular, with regard to mobility allowance.

CRE's analysis

CRE agrees with the general analysis of the auditor, but made several adjustments. CRE shares the auditor's proposal to size staff increases in coherence with the increase in assets and/or action volumes planned by RTE for the next tariff period.

With regard to assumptions concerning the change in national minimum wage for the electricity and gas industries, CRE does not adopt the auditor's adjustment, but RTE's proposal. However, CRE adopts the auditor's adjustment associated with the age and job-skill coefficient [confidential] and the auditor's adjustment concerning incentives and profit – sharing contributions.

Therefore, for this expense item, CRE adopts an average adjustment of -€14 million/year leading to an average trajectory of €1,003 million/year for the TURPE 6 period.

Taxes:

The auditor proposes a downward adjustment of -€4 million/year on the envelope fortaxes, i.e. a 0.6% difference compared to RTE's proposal. This adjustment mainly concerns the regional levies (CFE - CVAE[56]) and the property taxes for which the auditor conducted a separate analysis of the collection basis and the forecast contribution rates, in particular by studying the record of municipal and inter-municipal rates.

CRE's analysis

CRE agrees with the auditor's adjustments of the "taxes" item.

Therefore, for this expense item, CRE adopts an average adjustment of -€4 million/year (excluding 2021 DFL impact) leading to an average trajectory of €543 million/year for the TURPE 6 period (also taking into account the 2021 DFL impact).

Efficiency objective:

In addition to the item-to-item analysis, the auditor assessed RTE's forecast expenses and revenues on the basis of an overall net OPEX analysis (excluding purchases relating to electricity system operation), in order to evaluate the evolution of RTE's overall efficiency. The auditor therefore compared the efficiency level reached over the 2017-2019 period with the forecast efficiency levels corresponding to RTE's tariff proposal as well as with the auditor's proposal resulting from the item-to-item analysis. This analysis breaks down into the assessment of the evolution of two ratios: "*Net OPEX on a like-for-like basis per kilometre of line*" and *"net OPEX on a like-for-like basis per number of transformers".*

To obtain the "*net OPEX on a like-for-like basis*", the auditor deducted from the net OPEX the expenses and revenues resulting from constraints that were external or too unforeseeable as well as items reflecting a growth in scope (for example, expenses due to legal obligations to control brush and undergrowth, painting expenses, compensation, penalties and reductions related to ancillary services and balancing, etc.).

The operator's analysis reveals that the two indicators increase in constant euros over the TURPE 6 period leading to a decline compared to 2019 of 5.7% in 2024 for the "*net OPEX on a like-for-like basis per kilometre of line*" ratio and 3.5% for the "*net OPEX on a like-for-like basis per number of transformers*" ratio.

The auditor therefore recommends an additional adjustment compared to the trajectory proposed following the item-for-item analysis aimed at recovering in 2024 the level of efficiency measured in 2019 through the two indicators considered.

The auditor therefore proposes an additional drop in the net operating expenses trajectory (excluding purchases relating to electricity system operation) of roughly €56 million/year, which corresponds to a productivity target for the operating expenses at nearly 1.7% as from 2022.

CRE's analysis

CRE considers that the principle of an efficiency goal as proposed by the auditor is relevant to the extent that it encourages the operator to maintain its overall efficiency level. The two indicators used are relevant and commonly used in international comparison studies of system operators. Moreover, RTE's performance in these two indicators

[56] CFE: Companies' property tax Companies' value-added contribution

improved between 2017 and 2019 and there is no reason for it to decline during TURPE 6 HTB given that the scope of the indicator excludes expenses seeing sharp increases. CRE however considers that the objective proposed by the auditor is too ambitious. CRE adopts an average adjustment of -€15 million/year over the TURPE 6 period.

Summary:

CRE's analysis leads to adopting a trajectory of net operating expenses for RTE (excluding purchases relating to electricity system operation) for the TURPE 6 period of an average €2,001 million/year over the period (2019-2021 evolution of +5.6% and average annual evolution of +1.3% over the 2021-2024 period). The trajectory proposed by CRE presents a €165 million/year difference compared to RTE's proposal of €2,166 million/year including €70 million/year due to the drop in production taxes.

The trajectory of net OPEX excluding purchases related to electricity system operation adopted over the TURPE 6 period is as follows:

Table 9 : Trajectories of net OPEX excluding purchases related to electricity system operation adopted by CRE (in €million$_{nominal}$)

In €million$_{nominal}$	2019 Actual	2021	2022	2023	2024	TURPE 6 average
RTE's proposal – Net OPEX excluding purchases relating to electricity system operation)	1,858	2,089	2,138	2,196	2,242	**2,166**
		-125	-140	-185	-198	**-162**
Trajectory of net OPEX excluding purchases related to electricity system operation	**1,858**	**1,964**	**1,998**	**2,011**	**2,044**	**2,004**

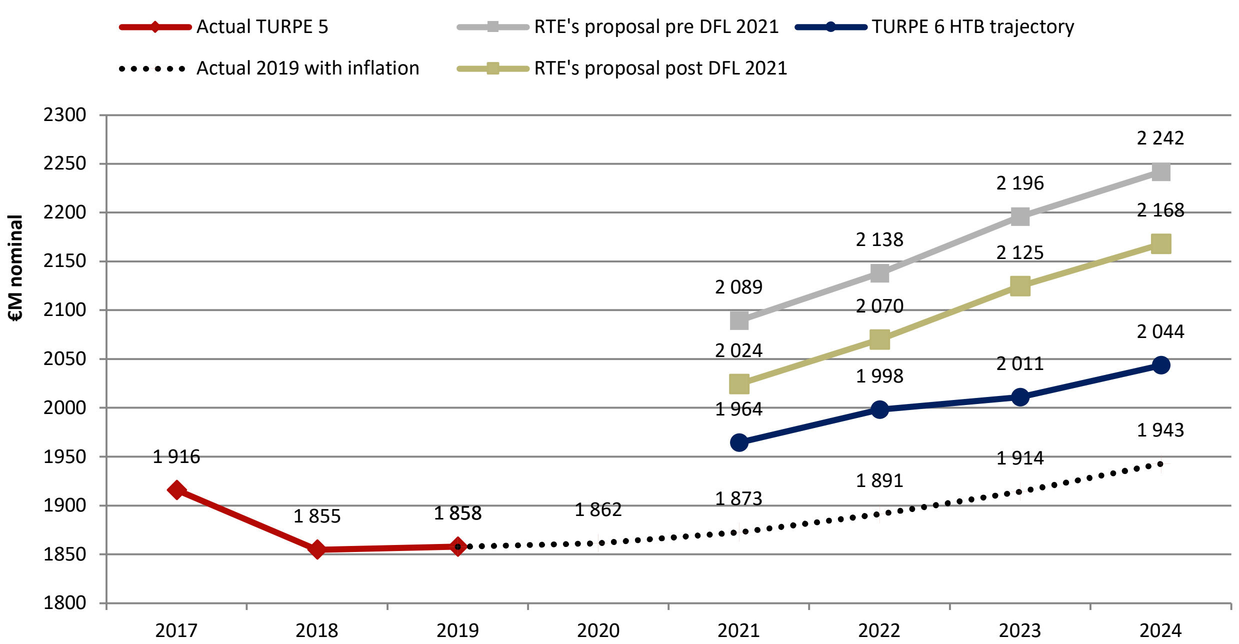

Figure 3 : Trajectories of net OPEX (excluding purchases related to electricity system operation) (in €million$_{nominal}$)

3.1.2.5 Summary

The following table summarises the trajectory of net operating expenses, resulting from the adjustments adopted by CRE for TURPE 6 HTB.

Table 10 : CRE trajectory – RTE's net operating expenses for TURPE 6 HTB

In €million$_{nominal}$	2019 Actual	2021	2022	2023	2024	TURPE 6 average
CRE trajectory - Net OPEX excluding purchases related to electricity system operation	1,858	1,964	1,998	2,011	2,044	2,004
CRE trajectory - purchases related to electricity system operation	848	980	937	942	964	956
CRE trajectory – Total net operating expenses	2,706	2,944	2,936	2,953	3,007	2,960

The trajectory adopted by CRE:

- gives RTE:
  - the means to conduct a proactive asset management policy by adopting its operations volumes assumptions in line with the TYNDP and which should enable it to control investments;
  - an increase in its staff in due proportion to the evolution of maintenance operations planned and enabling the successful implementation of projects to connect offshore wind farms and interconnection projects, and IS projects;
  - the means to address its growing IS needs and in particular its cybersecurity challenges, while taking into account the savings made possible by the projects previously undertaken;
  - the means to carry out an ambitious R&D policy;
- enables users to benefit from:
  - the drop in production taxes decided within the framework of the 2021 draft finance law;
  - cost reductions made possible by certain IS project investments;
  - an additional productivity effort during the TURPE 6 period.

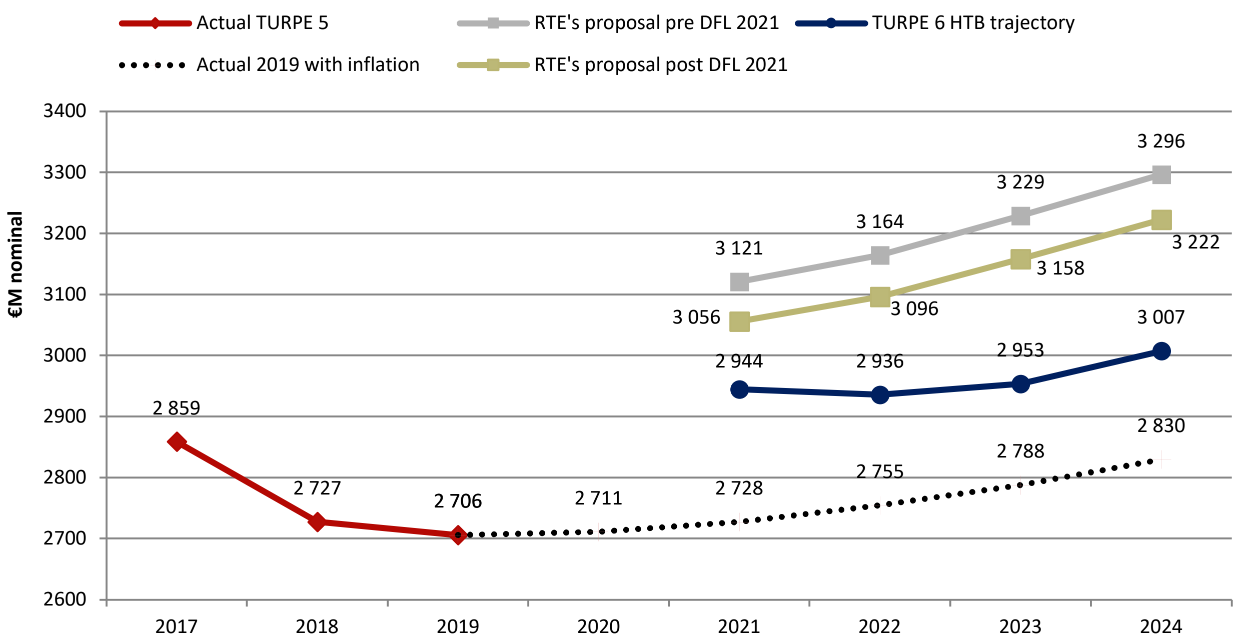

Figure 4 : Trajectory of net operating expenses (in €million$_{nominal}$)

3.1.3 Calculation of normative capital expenses

3.1.3.1 Weighted average cost of capital (WACC)

RTE's proposal

RTE presented a proposal for a weighted average cost of capital (WACC) of 5.35% nominal, before corporate tax, down compared to that of TURPE 5 HTB (6.125%). In addition, it proposed a rate of 2.55% nominal, before corporate tax, for the remuneration of AuC. This proposal is based on the conclusions of a study commissioned by RTE from an external consultant.

RTE proposes an upward revision of the asset beta, to 0.45 compared to 0.37 for TURPE 5 HTB. It justifies this increase by (i) the growth in investment needs and the greater complexity of projects, (ii) the change in electricity system management in a context of energy transition, (iii) the potential variation in the risk to which RTE is exposed because of changes in the regulatory framework, (iv) the mode envisaged for remunerating AuC and fully depreciated assets in service, which have increased and (v) the asset beta benchmark of comparable European regulated system operators determined by its consultant[57].

CRE's preliminary analysis

CRE examined the different parameters used in the calculation of the weighted average cost of capital. It commissioned a study by an external consultant to audit RTE's return on capital proposal. This study was published within the framework of the public consultation of 1 October 2020. On the occasion of this public consultation, CRE published a possible WACC ranging from 4.2% to 4.7%, nominal before tax.

CRE's public consultation

Among the contributors to the public consultation of 1 October 2020, most of them welcomed the drop in the remuneration rate envisaged by CRE, and agreed with the need to take into account the drop in market interest rates and the drop in the corporate tax rate in the calculation of the WACC. However, RTE and its shareholders defended a more moderate drop in the WACC, particularly through an increase in the beta, justified, in their opinion, by a greater risk profile (citing for example the increase in investments). RTE based its proposal on the betas of a panel of European regulated network operators.

Parameters adopted for TURPE 6 HTB

For the present deliberation, CRE adopts a WACC of 4.6% (nominal, before tax) to remunerate RTE's RAB. The values adopted by CRE for each of these parameters are shown in the table below:

Table 11 :Parameters in the calculation of the capital expenses of TURPE 6 HTB

Parameters in the calculation of capital expenses	TURPE 5 HTB	TURPE 6 HTB	
Nominal risk-free rate	2.7%	1.7%	A
Debt spread	0.6%	0.7%	B
Asset beta	0.37	0.37	C
Equity beta	0.73	0.78	D = C×(1+F/(1-F)×(1-G))
Market risk premium	5.0%	5.2%	E
Leverage (debt/(debt + equity capital))	60%	60%	F
Corporate tax (CT)	34.43%	26.47%	G
Tax deductibility for financial expenses	75%	100 %	H
Cost of debt (nominal, before CT)	3.7%	2.4%	I = (A+B)×(1-H×G)/(1-G)
Cost of equity (nominal, before CT)	9.7%	7.8%	J = (A+D×E)/(1-G)
WACC (nominal, before CT)	**6.125%**	**4.6%**	I×F+J×(1-F)

Compared to the values adopted in TURPE 5 HTB, the main developments concern:

[57] On the basis of its benchmark, the consultant commissioned by RTE presents a range of asset betas of comparable regulated European operators from 0.33 to 0.41 depending on the sample adopted and the reference period.

- the risk-free rate adopted standing at 1.7% is down 100 basis points compared to that adopted for the TURPE 5 tariff period (2.7%). This drop is justified by the significant and long-term fall in interest rates.

  CRE bases its decision concerning the value of the risk-free rate on the observation of the yields of French government bonds (“OAT”), considered as the most low-risk investments, for a period of ten years, and for OATs with a maturity of 15 years. Compared to TURPE 5 HTB, the maturity of the bonds considered went from 10 to 15 years. The lengthening of this maturity aims to better reflect the financing conditions of comparable operators.

- the asset beta, set at 0.37, stable compared to the level adopted for the previous period.

  CRE bases its decision concerning the asset beta on market observations and the betas of the activity of electricity operators in Europe. It also takes into account RTE’s regulatory framework which continues to protect the level of RTE’s revenues from most risks.

- furthermore, CRE takes into account the developments set out by the draft finance law for 2021, which confirms the expected drop in the standard corporate tax rate gradually until 2022, when a standard corporate tax rate of 25.0% will apply uniformly to all companies. Therefore, for the TURPE 6 period, CRE adopts a corporate tax rate of 26.47%, which is the average corporate tax rate applicable to RTE over the 2021-2024 period. The effect of this drop in the tax rate represents roughly 20 basis points in the drop in the WACC for TURPE 6 HTB compared to that in effect over the TURPE 5 period.

In compliance with what is described in section 2.1.2.3, the AuC are remunerated at the nominal cost of debt, before tax, i.e. 2.4%.

3.1.3.2 Investments

RTE’s proposal

The trajectory of investment expenses presented by RTE for the TURPE 6 period in its updated tariff proposal of July 2020 is marked by a growth in investments, with average expenses of €2,149 million/year over this period, compared to roughly €1,456 million in 2019, i.e. an increase of approximately +50%.

The investment expenses envisaged by RTE over the next tariff period compared to the current tariff period are presented in the graph below:

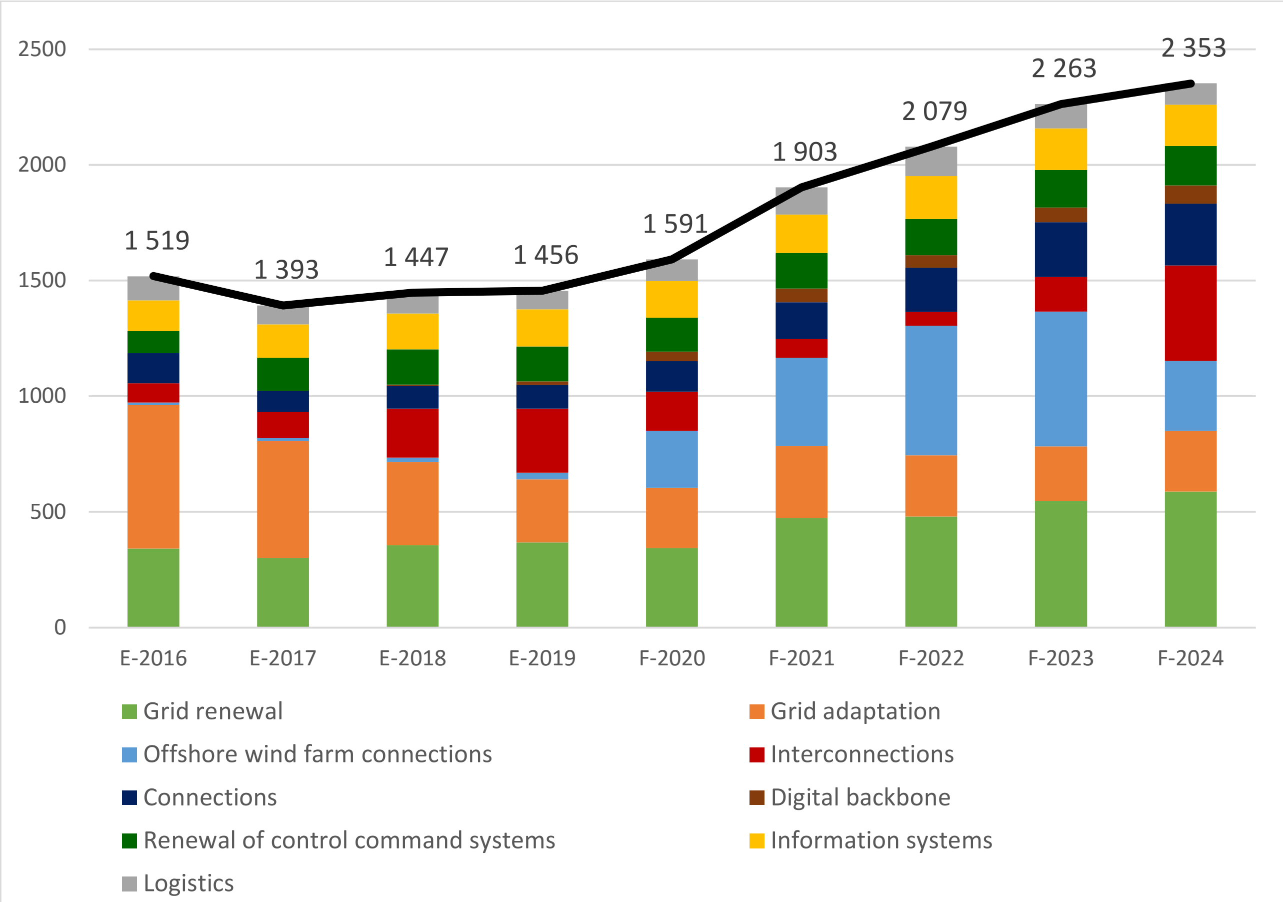

Figure 5 : Trajectory of RTE's investment expenses (in €million$_{nominal}$)

In particular, RTE projects:

- a major increase in expenses related to **offshore wind farm connections** (€457 million/year over the TURPE 6 period compared to €29 million in 2019) and to other **connections** (€213 million/year over the TURPE 6 period compared to €102 million in 2019), particularly for onshore renewable energy;
- a substantial increase in expenses related to the grid's **digital backbone** (€64 million/year over the TURPE 6 period compared to €15 million in 2019) related to the inclusion of telecommunications projects for an amount of roughly €40 million/year over the upcoming tariff period;
- a considerable increase in investment expenses associated with **grid renewal** (an average €522 million/year over the TURPE 6 period compared to €368 million in 2019). As specified in RTE's TYNDP, the annual expenses related to grid renewal will grow progressively over the tariff period, despite the asset management policy resulting in operating expense increases which should enable renewal needs to be limited;
- a small drop in **adaptation** expenses (an average €268 million/year over the TURPE 6 period compared to €273 million in 2019) and **interconnection** expenses (€176 million/year over the TURPE 6 period compared to €277 million in 2019). These expenses are marked in particular by the finalisation of the Savoie-Piémont project and the acceleration in the Celtic Interconnector and Biscay Gulf projects at the end of the tariff period;
- a +12% increase for **information systems** (€178 million/year for TURPE 6 HTB compared to €159 million in 2019). This increase illustrates the major importance of this item for the next tariff period, which is one of the pillars of RTE's transformation project and an essential requirement for the proper functioning of the electricity system;
- a +53% increase for **real estate**, with an average proposal of €81 million/year for TURPE 6 HTB compared to €53 million in 2019. This increase is driven by the construction of the regional headquarters of Lille and Marseille (an average €36 million/year) and the priority projects of restructuring or reconstruction of grid maintenance groups and sub-station unit divisions (an average €24 million/year).

CRE's analysis

The views of the contributors to the public consultation of 1 October 2020 are divided. While the majority reiterates that grid investments are one of the necessary elements for attaining energy transition objectives, others fear the impact of an increase in investment expenses on the electricity bill.

In compliance with its examination of RTE's TYNDP, CRE considers that an increase in investments in the power transmission grid has been made necessary by the energy transition and the need to renew the grid. In this context, it is even more important to ensure the relevance of the investment choices and to make them at the best cost.

Therefore, the present deliberation introduces a four-year cap accompanied by a financial incentive on some of RTE's investment expenses for the TURPE 6 period in order to encourage RTE to control and prioritise its investments, as explained in section 2.3.2.1. This cap is set at €3,967 million$_{\text{real}}$.

The projects that have been rejected by CRE, such as telecommunications infrastructure projects, within the framework of the approval by CRE of RTE's investment programmes, are not included in the investment trajectory set by the present deliberation, nor in the investment cap. The telecommunications projects concerned are as follows: the deployment of its own telecommunications infrastructure, Hermès, site-to-site LAN, and the INUIT extension. The investment and cap level could be subject to an update if satisfactory justifications brought by RTE lead CRE to approve these projects over the TURPE 6 period.

The projects for connection of offshore wind farms and high-voltage direct-current interconnections, which present high unit amounts and whose timetables depend heavily on factors outside of RTE's control, are not included in the four-year cap. For these two items, which are necessary for the energy transition, CRE adopts the investment expense trajectory proposed by RTE.

As previously stated, the four-year cap is set at €3,967 million$_{\text{nominal}}$[58]).

Table 12 : Grid investment expenses net of subsidies included in the cap (€million$_{\text{nomianl}}$)

€million$_{\text{nominal}}$	2021	2022	2023	2024	Total TURPE 6
Grid investment expenses net of subsidies included in the cap	1,011	973	963	1,020	3,967

Analysis of "*non-grid*" investments

"*Non-grid*" investments are subject to an incentive on the capital expenses (see section 2.3.2.5). The goal of this incentive regulation mechanism, which concerns expenses in information systems, real estate and light vehicles, items that can be subject to arbitration between investment expenses and operating expenses, is to encourage RTE to optimise all of these expenses on a whole in the interest of grid users.

For this purpose, a trajectory of capital expenses corresponding to the projected expenses for these three sub-items is set at the start of the tariff period, with a 100% incentive, such that the gains or losses are fully kept by the operator.

The auditor analysed the forecast trajectory of investments associated with these three sub-items in RTE's proposal, in order to assess its efficiency, and proposed some investment adjustments[59].

RTE's proposal for non-grid investments for the TURPE 6 period are summarised below:

[58] As a reminder, this trajectory is indicative and only serves to perform the follow-up explained in 2.3.2.1.

[59] The auditor's choice to study RTE's proposal in terms of investment expenses, while the TURPE 6 deliberation will ultimately define a capital expenses trajectory, enables analysis of RTE's proposal other things being equal, leaving aside the changes that could occur in the rate or mode of remuneration.

Table 13 :RTE's proposal – "*Non-grid*" investments for the TURPE 6 period (€million nominal)

€million nominal	Actual 2019	2021	2022	2023	2024	TURPE 6 average
RTE's proposal – "*non-grid*" investments	**215**	**257**	**288**	**261**	**247**	**264**
Information systems	159	167	186	180	179	178
Real estate	53	86	98	77	63	81
Light vehicles	4	5	5	5	5	5

With regard to the information systems, the trajectory proposed by the auditor for the TURPE 6 period is lower by roughly -€17 million/year on average compared to that of RTE (i.e. -9%). The auditor considers that certain non-priority projects, i.e. of which the main requirement is not related to a regulatory, obsolescence or security constraint, can be postponed by a year, leading to a drop in expenses over the TURPE 6 period. The auditor also recommended not including the expenses associated with a telecommunications project that RTE had included in one of its "non-grid" IS projects (the INUIT project), since this telecommunications project, like all the projects to develop its fibre optics network, had not been approved by CRE[60]. Moreover, the auditor considers that the new projects presented by RTE between its initial proposal and its updated proposal, are not priorities and can be postponed to TURPE 7. Lastly, the auditor also recalculated certain trajectories maintaining RTE's assumptions, leading to minor adjustments, and applied a standard method to resize RTE's diffuse adjustments, these adjustments enabling uncertainty of IS projects to be taken into account, particularly surrounding deployment timetables.

With regard to the real estate item, the trajectory proposed by the auditor for the TURPE 6 period is lower by roughly -€14 million/year on average compared to that of RTE (i.e. -17%). A large majority of the adjustments made by the auditor concerns "exceptional" projects and, to a lesser extent, projects related to its housing stock:

- project to construct the Lille and Marseille regional headquarters: the auditor adjusted the trajectory presented by RTE, and adopted the least expensive site for Marseille;
- projects for the restructuring or reconstruction of RTE's grid maintenance groups and sub-station unit divisions: the auditor applied the average unit cost observed over the 2017-2019 period for each type of operation;
- other exceptional projects: a project, lately identified by RTE, to upgrade the air conditioning system of dispatching rooms was deemed unessential by the auditor for the TURPE 6 period and therefore deferrable to the next tariff period. For the redevelopment of the H24 rooms, the auditor suggested using a single unit cost of work applied to all sites;
- project to renew the housing stock: the auditor revised downwards RTE's objective for the annual renovation of its housing stock.

With regard to light vehicles, the trajectory proposed by the auditor for the TURPE 6 period corresponds to an average trajectory of €4 million/year compared to €5 million/year proposed by RTE, i.e. an average drop of -€1 million/year. In that regard, the auditor considered that the growth of the vehicle fleet, which RTE attributed to the development of its activities and the increase in investments in the grid, was not justified.

The views of the contributors to the public consultation of 1 October 2020 were divided concerning the trajectory levels recommended by the auditor, particularly concerning information systems. Several participants drew CRE's attention to the essential role of IS tools, which will respond to energy transition challenges affecting the development of the grid and generating a greater need for digitalisation of RTE's internal processes. They also wished for the adjustments that will ultimately be adopted regarding IS project expenses to enable RTE to continue to operate the electricity system under satisfactory conditions.

<u>CRE's analysis</u>

CRE globally agrees with the auditor's approach concerning the three "*non-grid*" investment sub-items.

With regard to IS, CRE adopts an adjustment of an average -€11 million/year compared to RTE's proposal (i.e. -6%), corresponding to the inclusion of a portion of the adjustments related to the non-prioritisation of a few projects for

[60] CRE's deliberation of 20 December 2018 approving RTE's investment programme for the year 2019. In its proposal for TURPE 6, RTE included an average €6 million/year in investment expenses related to the Hermès project within the scope of INUIT.

which RTE has not provided sufficient justifications, and to the inclusion of the adjustments resulting from trajectory recalculations by the auditor. CRE does not adopt the adjustment proposed by the auditor regarding the INUIT project, because these additional expenses are necessary for the materialisation of the benefits of the project. CRE however corrected the trajectory of the operating expenses of the telecommunications projects so as to integrate the savings made possible by this project (see section 3.1.2.3). Lastly, CRE does not adopt the adjustment proposed by the auditor regarding the diffuse adjustments, considering that the method used by RTE is more relevant.

In total, CRE adopts an increase in investments related to IS projects of almost 5% on average, on a comparable basis, over TURPE 6 HTB compared to 2019. This decision materialises the fundamental importance, in CRE's eyes, of RTE's information systems for the French electricity system. TURPE 6 HTB therefore gives RTE all of the resources necessary to contribute to the energy transition and to continue to improve the functioning of the electricity market.

Concerning real estate, CRE adopts an adjustment of an average -€7 million/year compared to RTE's proposal excluding the Lille and Marseille projects (i.e. -15%) based on the following analysis:

- inclusion of all of the adjustments to the projects for the reconstruction or restructuration of the grid maintenance groups and sub-station units, since the elements provided by RTE did not justify the economic value of certain significant projects responsible for the increase in the unit cost and the volumes of the different operations;
- rejection of the auditor's adjustment proposal regarding the two other exceptional projects (upgrading of the air conditioning system of the dispatching rooms and development of the H24 rooms) and regarding the project to renovate the housing stock, since RTE's arguments presented to CRE to justify the trajectories are relevant.

In addition, with regard to the Lille and Marseille projects, since the public consultation of 1 October 2020, RTE informed CRE of a postponement of the Lille project because of an administrative appeal related to its building permit, and its wish to launch a new call for tender for the Marseille project because of a termination of commercial relations with the developer initially adopted. As a result, and given the uncertainty concerning the amount and the timetable of these two projects, in compliance with section 2.3.2.6, CRE decides not to attach an incentive to them under the incentive for controlling non-grid capital expenses, and adopts the last investment trajectories updated by RTE. These investments will therefore be treated like grid investments and will be subject to the incentive regulation for controlling the costs of major projects.

Moreover, CRE requests RTE resubmit these two projects for its approval once they are mature.

With regard to light vehicles, CRE agrees with the auditor's analysis and therefore adopts an adjustment of an average -€1 million/year compared to RTE's proposal.

All of the adjustments adopted by CRE for these three "*non-grid*" categories, excluding the Lille and Marseille projects, represents an average -€18 million/year compared to RTE's proposal excluding the Lille and Marseille projects (i.e. -8%), and leads to an average trajectory of €209 million/year, as presented in the table below:

Table 14 : RTE's "*non-grid*" investments for the TURPE 6 period (€million$_{nominal}$)

€million$_{nominal}$	2021	2022	2023	2024	TURPE 6 HTB average
RTE's proposal – "*non-grid*" investments (excluding Lille and Marseille projects)	220	239	230	220	227
Adjustment adopted by CRE	-8	-18	-23	-24	-18
Trajectory adopted by CRE	**211**	**221**	**207**	**196**	**209**
Information systems	162	174	167	163	167
Real estate (excluding Lille and Marseille projects)	45	43	36	28	38
Light vehicles	4	4	4	4	4

Table 15 : Investments in the Lille and Marseille building projects

€million$_{nominal}$	2021	2022	2023	2024	TURPE 6 HTB average
RTE's proposal	38	49	31	28	36
Trajectory adopted by CRE	1	46	15	28	23

The present deliberation adopts, for RTE's investment expenses for TURPE 6 HTB, the trajectory summarised in the table below:

Table 16 :Investment trajectory adopted by CRE (€million$_{nominal}$)

In €million$_{nominal}$	2021	2022	2023	2024	TURPE 6 HTB average
Grid adaptations	311	265	236	263	268
Connections to offshore wind farms	383	560	582	303	457
Digital backbone	46	16	18	16	24
Interconnections	80	61	150	412	176
Connections	158	190	236	267	213
Grid renewal	473	479	548	588	522
Renewal of control command systems	153	157	162	170	161
Information systems	162	174	167	163	167
Real estate and logistics	77	117	79	85	90
Total	1,844	2,020	2,178	2,267	2,077

3.1.3.3 Investment subsidies and contributions received from third parties

The subsidies and contributions received from third parties correspond in particular to the European subsidies received within the framework of interconnection projects, the share of S3REnR and more generally to the share borne by RTE's clients within the framework of grid connections. In its tariff proposal for TURPE 6 HTB, RTE plans to receive the following subsidies and contributions from third parties:

Table 17 : Estimate of third-party subsidies and contributions received by RTE (€million nominal)

In €million nominal	2021	2022	2023	2024
Third-party subsidies and contributions	226	234	323	482

The third-party subsidies and contributions effectively received by RTE will be deducted from the value of assets entering the RAB.

3.1.3.4 Normative capital expenses

The forecast RAB and AuC amounts adopted by RTE for the TURPE 6 period are as follows:

Table 18 : Regulatory asset base and assets under construction (€million nominal)

In €million nominal	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Regulatory asset base (RAB)	14,313	14,770	15,499	15,934	16,656	15,715
Assets under construction (AuC)	1,979	2,500	2,405	2,669	2,789	2,591

The forecast RAB and AuC amounts adopted for the normative capital expenses for the TURPE 2021-2024 period are as follows:

Table 19 : Trajectory of capital expenses

In €million nominal	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Depreciation covered by the tariff	859	946	978	1,027	1,080	1,008
Return on capital, assets in service	877	679	713	733	766	723
Return on capital, AuC	73	60	58	64	67	62
Total capital expenses	**1,809**	**1,685**	**1,749**	**1,824**	**1,913**	**1,793**
Of which "non-grid" CCN (excluding Lille and Marseille projects)	148	189	207	223	235	213

As presented in section 2.3.2.5, for the TURPE 6 period, CRE is readopting an incentive regulation mechanism for "*non-grid*" capital expenses.

The forecast RAB trajectories taken into account within the framework of the incentive regulation mechanism for "*non-grid*" capital expenses are as follows:

Table 20 : "*Non-grid*" regulatory asset base (€million$_{nominal}$)

In €million$_{nominal}$	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Information systems RAB (as at 01.01.Y)	286	407	440	463	486	449
Real estate RAB (as at 01.01.Y) (excluding Lille and Marseille projects)	251	299	329	354	368	337
Light vehicle RAB (as at 01.01.Y)	22	22	20	18	17	20
Total "*non-grid*" RAB	**559**	**728**	**790**	**835**	**871**	**806**

The forecast AuC trajectories taken into account within the framework of the incentive regulation mechanism for "*non-grid*" capital expenses are as follows:

Table 21 : "*Non-grid*" assets under construction (€million$_{nominal}$)

In €million$_{nominal}$	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Information systems AuC (as at 01.01.Y)	215	214	218	232	225	222
Real estate AuC (as at 01.01.Y) (excluding Lille and Marseille projects)	56	76	64	54	46	60
Light vehicle AuC (as at 01.01.Y)	1	1	1	1	1	1
Total "*non-grid*" AuC	273	291	284	287	272	283

The forecast amounts of "*non-grid*" capital expenses are as follows:

Table 22 : "*Non-grid*" capital expenses (€million nominal)

In €million nominal	2021	2022	2023	2024	TURPE 6 average
Information system capital expenses	143	159	174	185	165
Information systems return on capital	*24*	*25*	*27*	*28*	*26*
Information systems depreciation	*120*	*134*	*147*	*158*	*139*
Real estate capital expenses (excluding Lille and Marseille projects)	38	41	43	44	42
Real estate return on capital	*16*	*17*	*18*	*18*	*17*
Real estate depreciation	*23*	*25*	*26*	*26*	*25*
Light vehicle capital expenses	7	7	6	6	6
Light vehicle return on capital	*1*	*1*	*1*	*1*	*1*
Light vehicle depreciation	*6*	*6*	*5*	*5*	*5*
Total "*non-grid*" capital expenses	**189**	**207**	**223**	**235**	**213**

3.1.4 Revenues from interconnection capacity allocation and capacity mechanisms

As owner and operator of electricity interconnections between France and its neighbouring countries, RTE receives revenues from, on the one hand, the allocation of interconnection capacity, and on the other hand, the capacity mechanisms established in France and neighbouring countries, for the contribution of its interconnection capacity to the security of supply.

Under the provisions of article 19 of regulation (EU) 2019/943[61], the revenues resulting from the allocation of capacity must be used first and foremost for a) "*guaranteeing the actual availability of the allocated capacity including firmness compensation*" and b) "*maintaining or increasing cross-zonal capacities*". Once these priority objectives have been fulfilled, the revenues may be taken into account to fix the network access tariffs. In line with these provisions, interconnection revenues, similar to the costs aimed at guaranteeing the firmness of products allocated, as well as the normative capital expenses of investments to maintain or increase interconnection capacities, are included in the CRCP.

In its public consultation of 1 October 2020, CRE presented RTE's proposal concerning interconnection revenues, including both the revenues resulting from interconnection capacities and from capacity mechanisms. This trajectory corresponded to average revenues of €363 million/year over the TURPE 6 period.

Table 23 : RTE's proposal - Projected interconnection revenues over the TURPE 6 period

€million nominal	2021	2022	2023	2024	TURPE 6 average
Interconnection revenues	426	321	354	350	363

This forecast trajectory was updated to take into account the most recent information available. In particular:

- the assumptions of price spreads between France and its neighbours were updated to take into account the quotes from 19 to 30 October 2020;
- the assumptions of available capacity were updated to take into account the progress in the construction or maintenance work on certain infrastructure (Savoie-Piémont project, IFA2 project and the reinforcement of the Avelin-Avelgem-Horta line in particular);

[61] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market in electricity

- the assumptions of revenues resulting from capacity mechanisms were updated to take into account the result of the auction of 25 October 2020 concerning the French capacity mechanism for the year 2022 and the result of the capacity mechanism auction in the United Kingdom for delivery periods from October 2022 to the end of September 2024.

The update of these assumptions leads to a forecast revenue trajectory of an average €366 million/year over the TURPE 6 period.

CRE adopts this trajectory for the preparation of TURPE 6 HTB.

Table 24 : TURPE 6 – Interconnection revenues (€million$_{nominal}$)

€million$_{nominal}$	2021	2022	2023	2024	TURPE 6 average
Interconnection revenues	419	360	343	342	366

3.1.5 CRCP as at 1 January 2021

The total estimated amount of RTE's CRCP balance under TURPE 5 HTB to be taken into account in the calculation of the allowed revenue is +€5.8 million in favour of RTE, therefore being added to the allowed revenues of TURPE 6 HTB. This balance is due mainly to:

- tariff revenues lower than estimated (€304 million); this difference is due to the climate contingency seen in the first few months of the year 2020 and by the impact of the COVID-19 crisis on electricity consumption, corresponding to a drop in the quantities withdrawn in RTE's grid by about 30 TWh, i.e. -9% compared to the quantities withdrawn in 2019;
- interconnection revenues higher than expected (€120.4 million) which breaks down into a drop in revenues resulting from interconnection capacity allocation by €135 million compared to forecasts, i.e. -32%, and an increase in revenues resulting from capacity mechanisms by €255.4 million (the TURPE 5 HTB forecast included an assumption of €11.9 million in revenues for the English capacity mechanism, but did not include any revenues in connection with the French capacity mechanism);
- purchases relating to electricity system operation lower than estimated by €136 million; this difference is due in particular to a forecast cost of frequency ancillary services lower than estimated by €105 million;
- normative capital expenses lower than expected by €71 million, because of lower recurring investment expenses, compared to RTE's forecast trajectories.

Table 25 : CRCP balance as at 1 January 2021

	Amount (€million2020)
CRCP balance as at 1 January 2020	2,8
Consideration of the staggering of the deductible for the Window building in accordance with the TURPE 5 HTB deliberation	20,1
Forecast differences in 2020 for items included in the CRCP	-17,2
of which difference anticipated for tariff revenues	*303,9*
of which difference anticipated for interconnection revenues	*-120,4*
of which difference anticipated for purchases related to electricity system operation	*-135,6*
of which difference anticipated for normative capital expenses	*-71,0*
of which difference anticipated for net book value of demolished assets	*-4,7*
of which difference anticipated for ancillary service compensation	*19,3*
of which inflation difference anticipated for OPEX outside CRCP	*-8,8*
Discounting at the risk-free rate of 2.70%	0,1
Forecast CRCP balance as at 1 January 2021 (€million2021)	5,8

CRE readopts the CRCP reconciliation method used for TURPE 5 HTB. The CRCP balance for TURPE 5 HTB, as at 1 January 2021, will therefore be reimbursed through equal instalments over the four-year period of TURPE 6 HTB, i.e. €1.5 million/year to be added to the expenses to be covered.

The CRCP balance for 2020 taken into account by the present deliberation is a provisional amount. The definitive amount will be taken into account when the tariffs are updated as at 1 August 2022.

3.1.6 Allowed revenue for the 2021-2024 tariff period

RTE's allowed revenue for the 2021-2024 period is defined as the sum of the following elements:

- net operating expenses (see section 3.1.2);
- normative capital expenses (see section 3.1.3);
- interconnection revenues (see section 3.1.4);
- reconciliation of the CRCP balance calculated as at 1 January 2021 (see section 3.1.5).

It breaks down as follows:

Table 26 :Allowed revenue for the TURPE 6 HTB period (€million$_{nominal}$)

In €million$_{nominal}$	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Purchases related to electricity system operation	848	980	937	942	964	956
Net operating expenses excluding purchases related to electricity system operation	1,858	1,964	1,998	2,011	2,044	2,004
Normative capital expenses	1,809	1,685	1,749	1,824	1,913	1,793
Interconnection revenues	-450	-419	-360	-343	-342	366
CRCP reconciliation	29	1	1	1	1	1
Allowed revenue	**4,094**	**4,212**	**4,326**	**4,435**	**4,580**	**4,388**

The average level of RTE's expenses to be covered for the TURPE 6 period (net OPEX + normative CAPEX – interconnection revenues) will total an average €4,387 million per year. Over the 2019-2024 period, it will be updated by an average +2.4% per year, as a result of an increase in operating expenses by an average +2.3% per year, an increase in normative CAPEX by an average +1.1% per year and a drop in interconnection revenues by -5.4% per year.

RTE's allowed revenue (expenses to be covered to which CRCP reconciliation is added) thus changes by +2.9% between 2019 and 2021, and by an average +2.8% per year over the TURPE 6 period.

3.2 Withdrawal and injection assumptions

3.2.1 Changes recorded in the period covered by TURPE 5 HTB

TURPE 5 HTB projected over the 2017-2020 period a stability in power subscribed and an average change in energy withdrawn of -1.1% per year, excluding climate effects.

Over the 2017-2019 period, subscribed power was lower by an average 4.6 GW per year compared to the forecast trajectory of TURPE 5 HTB, i.e. -4.8%, because the forecast provided by RTE for the preparation of TURPE 5 HTB did not take into account the elimination of subscribed power for HTB 3 customers. Energy withdrawn was lower by an average 7.3 TWh per year compared to the forecast trajectory of TURPE 5 HTB, i.e. -1.7%. With an adjustment for climate variations, the difference is an average 6.7 TWh. This drop in withdrawals, greater than what was forecasted, is mainly due to efforts to control energy demand and the faster development of renewables connected to the public distribution grid, whose production reduces net withdrawals of distribution substations from the public transmission network.

For 2020, the estimates of the effects of the COVID-19 crisis show a difference between forecast and actual withdrawals of -27.5 TWh, i.e. -6.5% excluding climate effects, and -29.9 TWh, i.e. -7.1% including climate effects.

Table 27 :Power subscribed and energy withdrawn in the transmission grid over the TURPE 5 period

		2017		2018		2019		2020	
		Proj. TURPE 5	Actual	Proj. TURPE 5	Actual	Proj. TURPE 5	Actual	Proj. TURPE 5	Estimated
Power subscribed (GW)		95.5	90.9	95.5	90.5	95.5	91.3	95.5	86.2
Energy withdrawn (TWh)	Under actual weather conditions	434.6	431.7	431.5	424.4	426.9	415.0	420.5	390.6*
	excluding climate effects*		429.6		424.7		418.5		398.1*

**includes an initial estimate of the effect of the COVID-19 crisis*

3.2.2 RTE's proposal

3.2.2.1 Withdrawals

RTE anticipates a 14.9 TWh drop in energy withdrawn, i.e. -3.6% between 2019 and 2021 due to the effect of COVID-19. Over the 2021-2024 period, RTE projects a near stability, due to:

- a structural drop related to the pursuit of the deployment of energy efficiency solutions, and the development of production connected to the distribution grids which will reduce net demand for the transmission grid, offset partially by a slight increase in the consumption of direct clients;
- a lasting drop in consumption because of the COVID-19 crisis, but whose effect will dissipate gradually

Table 28 :Forecast trajectory of energy withdrawals for 2021-2024 (source: RTE)

In TWh	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Forecasts in the initial tariff proposal (April 2020)	415.0	410.7	406.9	404.3	403.0	406.2
Updated forecasts (July 2020)	415.0	400.1	399.3	398.9	399.0	399.3
Of which DSO withdrawals	*345.1*	*332.5*	*331.7*	*331.3*	*331.2*	*331.7*

Moreover, RTE expects subscribed capacities to globally remain stable compared to the previous period. The COVID-19 effect is comparatively less marked than for withdrawals.

Table 29 :Forecast trajectory of subscribed capacities for 2021-2024 (source: RTE)

In GW	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Forecasts in the initial tariff proposal (April 2020)	91.3	90.9	90.8	90.6	90.6	90.7
Updated forecasts (July 2020)	91.3	90.6	90.6	90.6	90.6	90.6

3.2.2.2 Injections

RTE projects a small increase in total injections in the transmission grid[62] between the 2017-2019 period and the TURPE 6 period (2021-2024). RTE anticipates a drop of about 0.2% between 2019 and 2021, followed by a 0.8% increase per year between 2021 and 2024. This increase is due mainly to the development of renewables production in the HTB1 network.

Table 30 :Forecast trajectory of injections for 2021-2024 (source: RTE)

In TWh	Actual 2019	2021	2022	2023	2024	TURPE 6 average
Total injections	490.9	489.8	491.0	496.0	501.8	494.6
Of which injections subject to the injection component (HTB3 and HTB2)	451.4	444.7	442.0	442.6	443.7	443.2
Of which injections not subject to the injection component (HTB1)	39.5	45.1	49.0	53.4	58.1	51.4

3.2.3 CRE's analysis

CRE analysed the trajectories for withdrawal, subscribed capacities and injections presented by RTE for the 2021-2024 period.

[62] These injections correspond to all of the energy injected in the transmission network by producers directly connected to the transmission grid as well as to backfeed from the distribution grids.

For the preparation of the tariff proposal, CRE had requested operators to coordinate to produce forecasts based on common assumptions. In compliance with this request, RTE and Enedis worked jointly to present consistent trajectories.

CRE considers that RTE's forecasts are consistent, both with the last values actually recorded and the developments underway in the electricity system. These developments mainly result from the development of decentralised production from renewable energy sources in a context of stable demand. Moreover, these assumptions take into account the impacts of the COVID-19 crisis on electricity consumption and therefore on withdrawals, which extend up to the year 2024.

CRE therefore adopts RTE's assumptions concerning withdrawals, subscribed capacities and injections. These assumptions, particularly the drop in withdrawals, mechanically increase the unit tariff.

3.3 Consideration of the tariff reduction for electricity-intensive customers

Article L. 341-4-2 of the energy code, created by article 157 of law no. 2015-992 of 17 August 2015 on the energy transition for green growth, provides for a reduction to be applied to the tariffs for the use of the public electricity transmission grid paid by sites that are heavy electricity consumers having a foreseeable or countercyclical consumption profile.

This article states in particular that "*the tariffs for the use of the public electricity transmission grids applicable to sites that are heavy electricity consumers having a foreseeable and stable or countercyclical consumption profile are reduced by a percentage set by decree compared to the tariff for the use of the public transmission network normally paid. This percentage is determined taking into account the positive impact of these consumption profiles on the electricity system*".

Decree no. 2016-141 of 11 February 2016 on the electricity-intensive status and the reduction in the tariff for the use of the public transmission grid granted to heavy electricity users specifies the categories of beneficiaries of this mechanism, the conditions that must be met by these sites in order to obtain the reduction and the reduction percentage they can claim.

Article D. 341-11-1 of the energy code, as amended by decree no. 2017-308 of 9 March 2017 amending the provisions relating to the electricity-intensive status and the reduction in the tariff for the use of the public transmission grid granted to heavy electricity users, states that "*for application of the second paragraph of article L. 341-4-2, compensation is paid to the infrastructure operators mentioned in the third paragraph, other than the public transmission system operator, which covers the net expenses they incur because of the application of the provisions of the present section. The amount of this compensation is established by the Energy Regulatory Commission in the light of the accounts of the concerned system operator*".

In accordance with article L. 341-4-2 of the energy code, the TURPE HTB level takes into account the loss of revenues that this mechanism implies for RTE.

In its public consultation of 1 October 2020, CRE stated that the loss of revenues due to this mechanism over the TURPE 6 period would total €179 million/year, i.e. RTE's estimate (€173 million) adjusted for the tariff evolution and structure developments.

CRE has updated this estimate to take into account the impact of the new TURPE 6 HTB tariffs. The trajectory adopted by CRE is presented in the table below:

Table 31 :Reduction for electricity-intensive sites (€million$_{nominal}$)

In €million$_{nominal}$	2021	2022	2023	2024	TURPE 6 average
Reduction for electricity-intensive sites	166	170	175	181	173

Since this item directly affects RTE's tariff revenues, it is included in the scope of the CRCP.

3.4 Trajectory of the tariffs for the use of the public electricity transmission grids

TURPE 5 HTB was characterised by an initial increase in the tariff level by +6.76%, which then changed according to inflation. With regard to TURPE 6 HTB, CRE, attached to the principle of tariff continuity, wishes to prevent an increase as at 1 August 2021 in the tariff level, possibly combined with the effects of tariff structure developments, from having too great of an impact on grid users. Therefore, the increase in the tariffs are smoothed over the TURPE

6 period on the basis of the trajectory of expenses to be covered and assumptions of withdrawals, subscribed capacities and injections as well as on the basis of the reduction granted to electricity-intensive sites over the tariff period.

The tariffs applicable as at 1 August 2021 are defined in chapter 5 of the present deliberation. They correspond to an average TURPE 6 HTB update for all users of +1.09% as at 1 August 2021 compared to the current tariffs and an average +1.57% per year over the entire tariff period, based on an average inflation assumption over the period of 1.07% per year.

The tariff update as at 1 August 2021, and the annual updates to the tariffs over the years 2022 to 2024, according to the principles defined in section 2.2.2, are determined so that the total projected revenues resulting from the application of the TURPE 6 HTB tariffs are equal, at discounted value from 2021 to 2024, to the total allowed revenue for the period.

Given the balance between forecast tariff revenues and allowed revenue over the 2021-2024 period and annual updates to the tariffs, annual differences between revenues and the allowed revenue may exist. The discounted sum of these annual differences over the period is, by construction, equal to 0.

Therefore, for the TURPE 6 period, the forecast allowed revenue and estimated revenues are as follows:

Table 32 :Projected allowed revenue and tariff revenues over the TURPE 6 period

In €million$_{nominal}$	2021	2022	2023	2024	Net present value
Forecast allowed revenue	4,212	4,326	4,435	4,580	16,823
Forecast tariff revenues (excluding reconciliation of the CRCP balance)	4,294	4,343	4,413	4,499	16,823
Annual differences between projected revenues and projected allowed revenue	82	17	-22	-82	0

For indicative purposes, the elements underlying this tariff balance are as follows:

Table 33 :Forecast evolution of TURPE HTB over 2021-2024

	2021	2022	2023	2024
Forecast inflation between *N-1* and year *N*	0.60%	1.00%	1.20%	1.50%
Update factor X	0.49%	0.49%	0.49%	0.49%
Forecast change as at 1 July of year *N* (excluding reconciliation of the CRCP balance)	1.09%	1.49%	1.69%	1.99%

4. STRUCTURE OF THE TARIFF FOR THE USE OF THE PUBLIC ELECTRICITY TRANSMISSION GRIDS

The tariff structure corresponds to the way in which grid costs are allocated to the different types of users, through different tariff components. This allocation aims to make each user pay the costs that they generate through their use of the power grid. In seeking to reduce and optimise their bill, the user reduces the costs they generate for the grid, in the short and long term.

The role of the tariff structure is strengthened by the transformation of the electricity system. While annual electricity consumption in France has globally been stable for several years now (apart from the drop seen in 2020 due to the COVID-19 crisis), the challenge for the network lies mostly in the capacity to meet peak electricity demand marked primarily by thermosensitive uses (electric heating). In addition, the accelerated development of wind and photovoltaic farms as well as new technologies (storage, electric vehicle steering, flexibility, etc.) raises new challenges while also bringing new opportunities to system operators.

In this context, CRE undertook work to develop the tariff structure, so that it can support the evolution in uses by correctly reflecting the associated costs and benefits. To this end, CRE drew on more refined grid data, submitted by operators, as well as on the load curves directly submitted by users, in response to CRE's different consultations. Given the challenges associated with tariff structure developments, the complexity of topics to be addressed and the need for visibility expressed by participants, CRE carried out very broad consultations on the changes envisaged, through three public consultations dealing with structure, between May 2019 and October 2020. Moreover, CRE shall publish the data, tools and models used to perform the structure work, with the exception of elements considered as secrets protected by law, so as to enable participants to adopt as best as possible the foundations and conditions for implementing these developments.

4.1 Grid pricing issues

4.1.1 Grid pricing principles

CRE builds the tariffs in compliance with several fundamental principles:

- "Stamp" pricing: pricing of network access is independent of the distance between the injection site and the withdrawal site;
- Standardised tariff: the same tariffs for network use apply across the whole national territory;
- Non-discrimination / cost reflection: pricing must reflect the costs generated by each user category independently of their final use of the electricity;
- Time and season variations: in compliance with article L. 341-4 of the energy code "*the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which consumption of clients on a whole is at its highest*". *They can also encourage their clients to limit their consumption during local peak periods [...]".*

Within this framework, CRE considers that in order to best meet the expectations of the different stakeholders, the tariffs for the use of the grids must reconcile the following objectives:

- Efficiency: a tariff signal best reflecting the grid costs generated by each user category serves to optimise investment needs in the long term because this information encourages the user to adapt their behaviour efficiently for the grid, which can imply different investment choices. The tariff signal thus ensures coordination between the investments made by the system operator and those made by users;
- Readability: the level of complexity of the tariffs must be adapted to the type of user of the voltage range in question. Grid costs vary in relation to time and localisation, based on congestion, the volume and cost of losses caused. A tariff perfectly reflecting costs would therefore be different at each hour and at each grid point. Such a tariff is not conceivable because it is too complex: it would not be very clear and the implementation costs related to its implementation would likely exceed the benefits. Therefore, the tariff structure is defined so as to reach the right balance between the reflection of investment and operating decisions by all participants (producers, customers and storage) on grid costs and the readability of tariffs through a limited number of relevant tariff coefficients;
- Feasibility: the tariffs must be implementable at a technical and operational level. The most significant example of this criterion is that meters must have the required number of indices;
- Acceptability: an evolution in the tariff structure will inevitably generate bill changes for all or part of users. This is particularly the case for users whose current tariff versions imperfectly reflect grid costs. The changes introduced by a new tariff must be gradual, so that all stakeholders maintain sufficient visibility

concerning TURPE evolutions. In addition, structure changes must not lead to bill changes that are clearly excessive compared to users' capacity to adapt.

These principles, unchanged since TURPE 5, were submitted for stakeholders' evaluation in CRE's public consultations of May 2019, March 2020 and October 2020. Contributors were widely in favour, supporting this approach for the TURPE 6 period.

4.1.2 The reflection of time and season variations on grid costs

The costs generated by grid use vary substantially depending on the period during which the grid is used. Basically, the increase in grid consumption at a time of low grid use generates a limited additional grid cost, related mainly to the increase in power losses, whereas a consumption increase when the grid use is high can generate congestion and cause, in the long term, costly grid reinforcement needs.

The power transmission grids are sized mainly to enable energy flow during the local peak (peak of the grid part in question) including when an infrastructure is unavailable. Therefore, the costs of these grids depend significantly on the power transmitted during the times when the grid is most heavily used. As illustrated in the following figure, these periods occur mainly in winter.

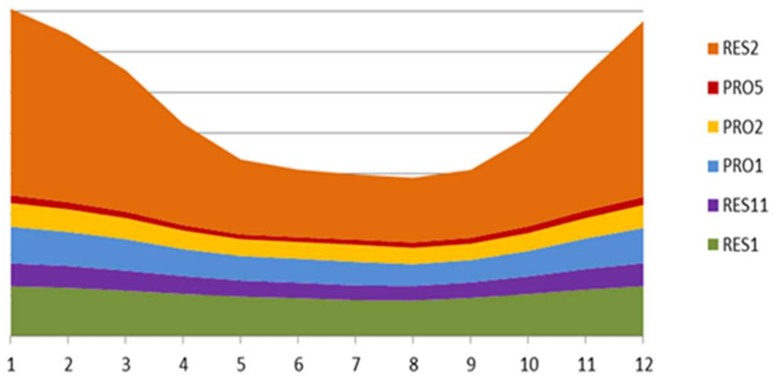

Figure 6 : Distribution, normalised to 100, of French electricity consumption of delivery points with low-voltage connections (<36 kVA) per month and per segment (source: Enedis)

This phenomenon is reflected by the time and season variations in tariffs: different tariffs based on the time of day and period of the year signal to users that the grid costs they generate are not the same based on the moment of use. By encouraging users to adapt their uses to optimise their individual bills, this tariff system serves to coordinate the operating and investment decisions of system operators and grid users. It thus contributes to better economic efficiency for the community as a whole. This approach has been used historically with success, in the form of integrated "peak /off-peak" supply offers, to limit the highest load demands at the start and end of the day, and therefore spread the load nationally during the day. Users' behaviour adapted, for example with the extensive use of load control for hot water tanks, to this type of tariff signals, generating in the long term significant savings in the sizing of the French electricity system.

4.1.3 Fair capacity/energy split

The need to set *ex ante* a clear and consistent tariff requires simplifications, while maintaining the objective of limiting local peaks at critical times for the grid.

Pricing based on subscribed capacity encourages each user to limit their individual peak and in so doing limit the grid peak. In that regard, it appears to be adapted to the specificities of the French network. However, a tariff passing on all costs based subscribed capacity would be counter-productive and would cause transfers among users. Users are not always present in exactly the same way at the highest load demand times: at an equal peak power, those present the longest during the highest load demand times generate more grid costs than those present only part of the time, which is reflected in pricing based on energy withdrawn.

One of the challenges of the tariff structure is to find the right balance between capacity-based and energy-based pricing.

4.1.4 Controlled bill increases

While the sending of economic signals is necessary for controlling grid costs and therefore bills in the long term, CRE is particularly attentive to the acceptability of tariffs in the shorter term and therefore to changes in bills associated with tariff structure modifications.

CRE took into account the concerns expressed by certain participants, in response to the different consultations, regarding their bill increases. It ensured that the changes introduced for the TURPE 6 period do not, in the short term, lead to consequences too significant or brutal in terms of billing for grid users. In particular, it has set up a smoothing over four years of the different changes (see section 4.3.3.2). Suppliers will therefore have an incentive to gradually take into account these developments in their offers, which will generate substantial grid savings that will benefit the community in the long term.

4.2 Conservation of the general structure of TURPE 5 HTB

4.2.1 Tariff components

The “grid costs” borne by the transmission and distribution system operators can be classified as follows:

- management and metering costs are costs that do not depend on the use of the grid as such, but on the type of service provided by the system operators based on voltage ranges and user categories concerned (costs of customer management, telephone assistance, billing and collection, maintenance of devices for measuring, metering and transmitting billing data, etc.);
- infrastructure costs are costs that are fixed in the short term (apart from congestion management costs, which are very low to date), but variable in the long term through investments;
- compensation costs for power losses are variable costs in the short term (and in the long term because of investments). Users’ contribution to these costs depends on the energy injected and/or withdrawn at the different times of the year;
- costs of reserves, corresponding to the costs for constituting balancing reserves (frequency control, reconstitution of ancillary services, manual frequency restoration and replacement reserves), interruptibility as well as voltage control costs;
- other costs, such as centrally-managed costs and other unallocated costs.

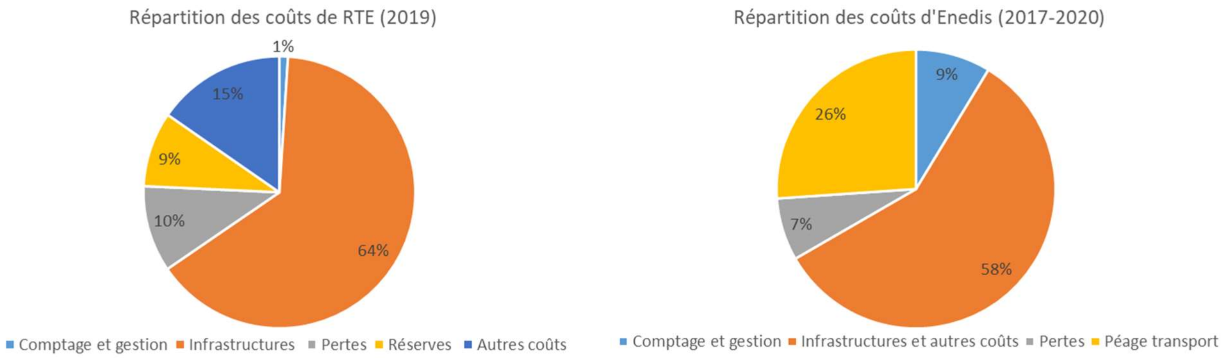

Figure 7 : Illustrative distribution of annual expenses borne by RTE and Enedis (source: RTE and Enedis data, CRE analysis)

These costs are passed on to grid users based on a set of components, differentiated by voltage level, which are as follows:

i. fixed components (€/year), which cover management and metering costs. These costs do not depend on grid use, but on the type of service provided by the system operators based on the voltage ranges and user categories concerned;
ii. a withdrawal component, which covers infrastructure costs, power losses compensation costs, reserves costs and the other costs not allocated by voltage range, such as centrally-managed costs. It includes:
    a. coefficients applied to subscribed capacity (€/kW/year), which reflect the contribution of users’ maximum demand to grid infrastructure costs;

b. coefficients applied to energy (€/kWh), which reflect, on the one hand, the contribution of the duration of use of the power subscribed to grid infrastructure costs and, on the other hand, the contribution of energy withdrawn to power losses compensation costs;

iii. an **injection component (€/MWh)**, which currently applies only to injections in the transmission grid at voltage ranges HTB 3 and HTB 2 and which reflect the contribution of energy injected to the cost for compensating power losses generated in the French grid by exported electricity, as well as the cost of power losses compensation billed to RTE under the Inter TSO compensation mechanism;

iv. **specific components** for specific services: subscribed capacity overruns, additional supply and backup, grouping, reactive energy, etc.

CRE considers that the recovery of costs according to the components presented above is appropriate, and proposed in its public consultations of May 2019 and March 2020, to maintain this breakdown in the following tariff. Contributors were largely in favour. CRE therefore decides to maintain for the TURPE 6 period the same tariff components as for TURPE 5.

4.2.2 Form of tariffs

In TURPE 5, CRE simplified the tariffs to move towards a model in which high-voltage users (HTB and HTA) are applied a tariff with five time categories, and low-voltage users a tariff with four time categories, based on seasons and time of the day. On top of this time differentiation, the tariff versions depend on the duration of use.

In its public consultations of May 2019, March 2020 and October 2020, CRE proposed maintaining the general form of tariffs, stating that following the harmonisation of tariffs introduced by TURPE 5, the current tariffs are a good balance between the pricing principles. Contributors were largely in favour. CRE therefore decides to adopt this proposal for the TURPE 6 period.

In its public consultation of May 2019, CRE proposed introducing a possibility of local flexibility regarding the definition of peak/off-peak times and low/high season for the tariff of the HTB1 and HTB2 voltage ranges, based on the flexibility model introduced for the HTA tariff in TURPE 5. CRE decides to adopt this proposal for the TURPE 6 period (see 5.2.1.4.2 and 5.2.1.4.3).

In addition, for the low-voltage level ≤ 36 kVA (private households and small businesses), options without seasonal differences had been maintained, due to the still limited proportion of Linky meters deployed during the TURPE 5 period and the goal to implement changes gradually. CRE stated in its different consultations that it wished to eliminate these options by the end of TURPE 6. Participants were generally in favour.

The form of tariffs adopted for the TURPE 6 period by voltage level is summarised in the table below:

Table 34 :Form of tariffs by voltage range

Expensive hours ← → Less expensive hours

	Super peak hours	Peak hours in high season	Off-peak hours in high season	Peak hours in low season	Off-peak hours in low season	
HTB3			✓			Energy-based tarif without time differenciation
HTB2 and HTB1	✓	✓	✓	✓	✓	Three versions (short/medium/long duration of use)
HTA	✓	✓	✓	✓	✓	Two versions (short/long duration of use)
BT > 36 kVA		✓	✓	✓	✓	Two versions (short/long duration of use)
BT ≤ 36 kVA		✓	✓	✓	✓	Two versions on 4 time categories (short/long duration of use)
				✓(*)	✓(*)	One version on 2 time categories (peak/off-peak hours) available until 2023 (*) : No seasonnal differenciation.
			✓			Two versions without time differenciation (short duration of use available until 2023 and long duration of use).

4.3 Evolution in the structure of TURPE 6 HTB

The tariff structure of TURPE 6 is based on the same principles as that of previous tariffs, with, in particular, the maintenance of the different components (metering, management, withdrawal, etc.) and the form of tariffs.

Work conducted by CRE, in collaboration with system operators and based on the detailed data they supplied, aim to guide the decisions of power grid users by conveying relevant price signals to them, reflecting the costs that their grid use generates for the community, in compliance with the principle of tariff equalisation.

4.3.1 Management component

The annual management component in the grid access contract covers the management costs for user files, physical and telephone reception of users, billing and collection.

According to the elements provided by RTE, its customer management costs over the 2015-2018 period totalled €37 million per year, while revenues resulting from the management component represented €31 million per year. In its public consultation of May 2019, CRE therefore envisaged increasing the component for management of users connected to the transmission grid by 18% in order to better cover the corresponding cost base. Since the management component had already increased by 11% between 2016 and 2020, CRE proposed in its public consultation of October 2020 to increase it by 6%.

Contributors to the public consultation were generally in favour of the increase in this component to cover RTE's management costs, but some participants deemed the increase too high.

CRE considers that the increase in the management component is necessary to fairly reflect RTE's management costs. Therefore, the management component of TURPE 6 HTB is reassessed at a level of €9,404 per year, enabling coverage of the corresponding cost base of €37 million per year, i.e. a 6.2% increase compared to the TURPE 5 HTB as at 1 August 2020.

4.3.2 Metering component

The metering component covers the cost of metering, control, transmission of meter readings, repair costs and, where applicable, the lease of metering devices.

The forecast trajectory prepared by RTE shows an increase in metering costs during the 2015-2022 period linked in particular to the "Continuous monitoring" project, followed by a drop as from 2023 related mainly to the decrease in the capital expenses associated with this project. In 2021, metering costs will have reached their maximum level of €30 million and the revenues associated with the metering component will have totalled €25 million. In 2025, this difference will have shrunk completely. The provisional nature of this difference leads CRE to not change the level of the metering component of TURPE 6 HTB compared to TURPE 5 HTB. It is only reevaluated to take into account the increase percentage set for 1 August 2021.

4.3.3 Withdrawal component

4.3.3.1 Method for constructing the withdrawal component

CRE consulted market participants about the changes envisaged regarding the construction of the withdrawal component, in March and October 2020. Participants were generally in favour. Some participants, including system operators, were particularly in favour of the methodology developments studied since these changes bring to light an access cost and increase capacity share in the tariffs. Conversely, some customers expressed their concern, particularly regarding the consequences on their bills of an increase in the capacity share.

For the TURPE 6 period, CRE adopts the changes presented during public consultations, but makes a few adjustments to respond to the legitimate concerns expressed by participants (see section 4.3.3.2).

As previously stated, the methodology adopted for TURPE 6 is based on the data submitted by system operators, which describe their costs, grids and energy flows more precisely than those transmitted for TURPE 5, as well as on the analysis of the load curves transmitted directly by grid users in response to the public consultation of October 2020. It builds on the method used for TURPE 5, while fine-tuning certain calculation stages, in particular:

- the determination of a cost function with economies of scale;
- the consideration of an access cost;
- the estimation of a local infrastructure cost;
- the calculation of marginal infrastructure costs;
- the allocation of costs for power losses compensation and balancing reserves based on energy flows between voltage levels.

The new method, described in detail in Annex 7, better reflects clients' access costs, which are hardly dependent on their effective use of the grid. The serving cost represents all of the costs for geographic coverage of the grid to supply all users, travelling to conduct interventions throughout the grid (taking into account smart metering which will reduce this travel), and specific regulatory constraints or requirements related to the physical scope of the grid.

In TURPE 5, the category of costs related to serving was not identified particularly because of the limitations on the data available at the time. The model adopted during the preparation of TURPE 5 was based on a national approach, with peak demand as the only factor behind infrastructure costs.

In TURPE 6, the tariff construction distinguishes:

- non-coincident peak load (local peak power related to the sum of users' load curves) as the factor behind the peak costs at the local level,
- coincident load (sum of users' individual load, used as a proxy for their number) as the reason for the access costs.

The main steps in the method are as follows:

- Step 1 – econometric study of infrastructure costs: this first step consists, using the analysis of the data of each grid pocket, in:
  - reconstituting the annualised cost of each pocket;
  - determining the variables most likely to explain the variations in costs between pockets;
  - deducing a cost function, to obtain marginal costs compared to the different cost drivers;
- Steps 2 and 2b – for the two main cost drivers selected (number of users, representing the access costs, and non-coincident peak load in each pocket, representing peak costs), the following step consists in transforming the local marginal costs into national tariff coefficients for subscribed capacity and energy withdrawn, using a large sample of representative users whose hour-by-hour grid use is known;
- Step 3 – adjustment and allocation of ancillary costs: this step consists firstly in adjusting the tariff coefficients homothetically to equalise the infrastructure revenues and expenses to be covered for each voltage range, then taking into account the ancillary costs (power losses, reserves, HTB 3) not included in the cost function established in step 1, and passing them on to consumers by integrating them in the tariff coefficients obtained in steps 2 and 2b.

The main steps of this method are shown in the diagram below:

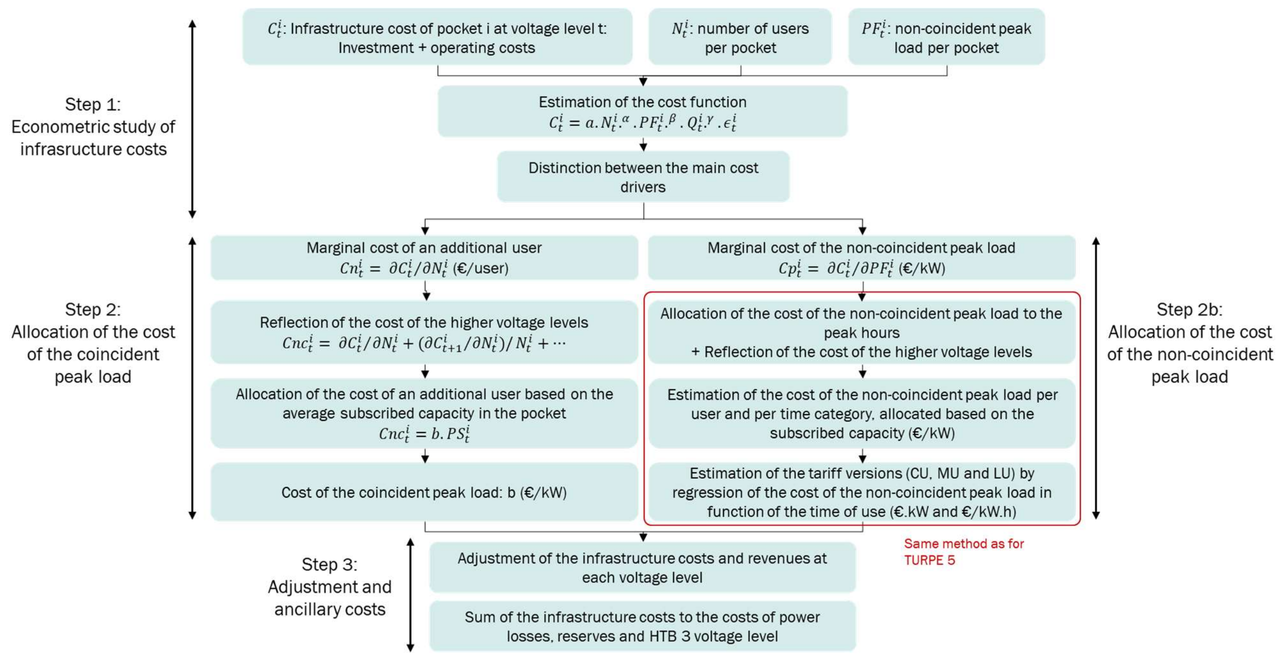

Figure 8 : Steps of the method adopted for TURPE 6

Cost allocation takes into account the fact that each user uses not only the voltage range to which they are connected, but also, by way of cascading, all of the voltage levels upstream of their own. For the HTB 3 network, steps 1 and 2/2b are simplified.

4.3.3.2 Effects of the change in method and smoothing of changes for HTB 1 and HTB 2 over four years

These developments lead, compared to TURPE 5 and at a constant overall tariff level, to changes in the tariffs and bills of certain users:

- an increase in the capacity coefficients, particularly for users choosing the short-use tariff versions. The inclusion of access costs (through an increase in the capacity coefficients, similarly for each voltage level – except HTB 3 – for all tariff versions and all time categories), these being largely independent of effective grid use, necessarily leads to bill increases in greater proportions for users having the shortest use durations. Nevertheless, CRE made sure that these increases remain bearable for all user categories (see section 4.1.4);
- an adjustment of the tariff differentiation between seasons and times of the day in order to better correspond to the reality of today's grids' load profiles;
  - energy coefficients are lower in the low season and higher in the high season for medium-voltage and low-voltage levels: the method adopted by CRE for the pricing of infrastructure costs in TURPE 6, being based on the marginal cost principle, leads to attributing most of the infrastructure costs to the times that are critical for the grid, more heavily than for TURPE 5. High consumption times occur most often during the high season, which has the main effect of reducing the cost of hours during the low season. Therefore, the method results in a greater time differentiation of the infrastructure costs allocated to the coefficients applied to energy withdrawn;
  - conversely, the time difference is less marked for the highest voltage levels (HTB 1 and HTB 2) except for users with the shortest use durations: the method adopted by CRE for TURPE 6 henceforth prices infrastructure costs and ancillary costs distinctly. The latter costs, which include the costs for power losses compensation and reserves, have a more moderate time differentiation compared to that of infrastructure costs (with HTB power losses and reserves varying less than withdrawals, HTB power losses rates and the reserves rates are higher in the low season). These ancillary costs, which represent €2 billion per year, i.e. roughly 13% of costs covered by TURPE HTB and TURPE HTA-BT, are, in proportion, higher for the high voltage levels. Therefore, for these voltage levels, the inclusion of ancillary costs generates increases in the energy coefficients in summer for long-use HTB 2 and HTB 1 users and medium-use HTB 2 users. Compared to TURPE 5, the total effect is a lowering of the time differentiation for HTB 2 and HTB 1 levels (except for short-use users). Since the public consultation of October 2020, CRE however took into account the seasonal nature of the prices of the different reserves (market prices being higher in the high season), which leads to increasing the time differentiation between the low season and the high season compared to the tariffs presented in the public consultation;
  - the difference between peak and off-peak times is less marked: when uses are directed to off-peak times, the difference in grid demand between peak and off-peak times narrows, particularly with storage water heaters which can transfer a major portion of consumption to off-peak times. The grids therefore are also heavily used during a portion of the off-peak times in the high season. This leads to a reduction in the differentiation between peak and off-peak times during the high season, because this occurrence had not been taken into account in TURPE 5. Moreover, this high grid demand during off-peak times in the high season, particularly in residential pockets, which could increase even more at local level with smart electric vehicle charging, requires specific attention by distribution system operators. One of the challenges in the future will be to correctly place off-peak times, based on the local specificities of each pocket.

The sizing of the HTB 3 grid is not directly related to withdrawal peaks, but rather to inter-regional and international flows which depend on local balances between production and consumption. In addition to infrastructure and power losses compensation costs, the withdrawal component resulting from the new method is now calculated explicitly taking into account the cost of reserves. This development leads to an increase in the HTB 3 withdrawal component of +3%, slightly higher than the general re-evaluation of the tariffs as at 1 August 2021.

On a whole, participants were in favour of the proposals made by CRE during the consultations of May 2019, March 2020 and October 2020. In particular, in their response to the last public consultation, many participants were in favour of the increase in the capacity share in the tariffs in order to support the change in uses related to the energy transition. Some participants wished for this increase in the capacity share of tariffs to be continued with the next tariff periods. RTE highlighted several improvements compared to the methodology used to prepare the TURPE 5 structure, and in particular the better inclusion of grid cost drivers and factors behind the cost variations in grid pockets, through the specification and setting of an infrastructure cost function. RTE also considers that the increase in the capacity share is also a step in the right direction within the context of a structural drop in the energy withdrawn and a stability in capacity subscribed. UFE (French electricity union) is in favour of the methodological development based on long-term marginal costs serving to distinguish an access cost.

However, some industrial participants are not in favour of the proposed changes since it can cause considerable bill evolutions for certain consumption sites. As explained in annex 4, the consumers concerned by a bill increase related to the change in the tariff structure are short-use users (low energy withdrawn/capacity subscribed ratio), and to a lesser extent, long-use users (high energy withdrawn/capacity subscribed ratio). Users with the shortest durations, for which the subscribed power coefficients increase significantly, consider that the bill increase caused by the TURPE 6 HTB structure is excessive. Users with the longest durations consider that the drop in the time differentiation goes against the contribution of the tariffs to the reduction of peak consumption.

The evolution in the methodology for constructing the withdrawal component can generate substantial changes for certain types of users, particularly those with the shortest duration of use. In order for all participants to be able to adapt accordingly their withdrawal habits and the optimisation strategy for their version and subscribed capacity selection, CRE decides to gradually apply the change in the methodology over the TURPE 6 HTB tariff period for the HTB 1 and HTB 2 voltage levels. This smoothing is implemented linearly between the TURPE 5 tariff of 1 August 2020 and the target TURPE 6 tariff of 1 August 2024. Reference tariffs for HTB 1 and HTB 2 is planned for each year of the TURPE 6 HTB period. The tariffs applicable each year will be obtained by applying the cumulated change in the average tariff level since 1 August 2021 to these reference tariffs, which are presented in section 5.2.2.2.

4.3.4 Reactive energy billing

In its public consultation of 1 October 2020, CRE proposed updating the billing of reactive energy for industrial customers, introducing a high voltage billing zone, and modifying the time interval used to calculate overruns (in hourly increments compared to a monthly basis for TURPE 5 HTB).

Most contributors are in favour of these changes. In addition, some participants suggest alternative levers for controlling voltage and in particular for the management of high voltage phenomena: remunerating renewables producers and storage units having the voltage capacity necessary for this service. On this matter, CRE reiterates that certain renewables producers connected to the HTB grid already take part in controlling voltage, and that RTE has begun consultations with renewables producers with HTA connections about the feasibility and the terms for remunerating such a service. RTE plans to launch a pilot phase on the voltage control service performed by renewables connected to the HTA network as from 2021.

CRE introduces in TURPE 6 HTB the following changes for the billing of reactive energy:

- the implementation of a "high voltage" billing zone, applied only outside of the winter period, in order to bill the over-injection of reactive power in the network. This high voltage zone, delimited by two thresholds[63] (see figure below), follows the same dimensioning logic as the one currently applied to distributors;
- the standardisation of billing time slots for all voltage levels concerning the low voltage zone;
- calculation of overruns in hourly increments.

With regard to the low voltage billing zone, it remains unchanged compared to TURPE 5 HTB, and continues to be billed only in winter from 1 November to 31 March, so as to not impose compliance in the summer with two constraints that are simultaneously incompatible at the operational level[64] for industrial players.

Within the framework of TURPE 6 HTB, the evolutions adopted lead to the following billing template:

[63] The "High voltage" zone is defined by two thresholds Pf and Qf which depend on subscribed power and are described in the reference technical documentation of the transmission system operator. The Pf and Qf thresholds result from the work conducted on the billing template applying to the interface between the public transmission grid and the public distribution grid for TURPE 5. Since the dimensioning logic for this zone is similar between industrial consumers and distributors, the threshold values are used identically to ensure homogeneity and rationalisation between the two billing templates.
[64] Indeed, it would be very difficult for an industrial consumer to comply in summer both with a reactive energy injection limit and a reactive energy withdrawal limit.

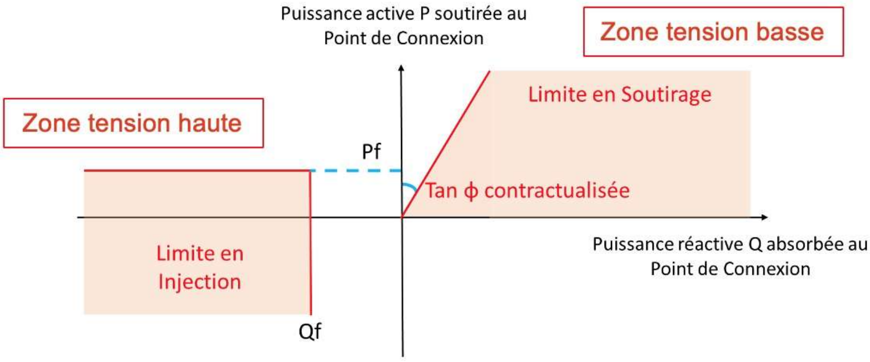

Figure 9 : Template for the billing of HTB reactive energy

The introduction of a high voltage billing zone for industrial consumers requires the definition of billing coefficients for high voltage zone. This change, as well as the switch to an hourly calculation, also requires reviewing the billing coefficients for the low voltage zone compared to those of TURPE 5 HTB.

The coefficients for TURPE 6 HTB are established based on the following approach:

- stability in the total amount billed to industrial consumers between the TURPE 5 period and the TURPE 6 period at €4 million/year, in order to avoid a widespread bill increase resulting from the above-mentioned changes ;
- equivalency between the costs borne by distributors and those borne by industrial consumers for the high voltage zone.

The billing coefficients for reactive energy overrun in TURPE 6 HTB result in an average breakdown of the billing envelope into 6% for high voltages and 94% for low voltages, which is a moderate incentive for compliance with the high voltage zone for this first period of implementation.

4.3.5 Injection component

The TURPE 5 HTB injection tariff covers the cost for compensating power losses generated in the transmission system by the exportation of electricity as well as the cost of power losses billed to RTE under the inter TSO compensation mechanism, which are directly attributable to producers connected to the HTB 3 and HTB 2 voltage levels. The injection charge stands at €0.20/MWh for the TURPE 5 period.

The expenses attributable to injections (power losses related to exports and the ITC portion covering power losses in cross-border networks) increase sharply for the TURPE 6 period because of (i) the increase in the power losses compensation cost and (ii) the +26% increase in exports projected by CRE between the 2016-2019 period (average exports: 79.1 TWh/year) and the 2021-2024 period (forecasted average exports: 99 TWh). Therefore, CRE proposed in its public consultation of October 2020 bringing the injection tariff to €0.23/MWh for injections in the HTB 3 and HTB 2 voltage levels.

Contributors to the consultation are divided concerning proposed increase. While it is deemed excessive by certain participants, RTE considers that it is necessary to ensure the proper coverage of the costs that this component is intended to cover. In addition, several contributors suggest extending the scope of the injection component to the HTB1 and HTA voltage levels, which will increasingly participate in electricity exports as the electricity mix develops.

Because of (i) the increase in energy and capacity prices for power losses compensation, (ii) the increase in exports and (iii) the drop in injections in the HTB 3 and HTB 2 voltage levels, CRE considers that an increase in the injection component is necessary to cover the cost for compensating power losses generated by the exportation of electricity and the ITC portion covering power losses, these costs being directly attributable to injections in the transmission grid.

Therefore, CRE sets the injection tariff at €0.23/MWh for producers connected to the gridss at HTB 3 and HTB 2 voltage level.

5. TARIFF FOR THE USE OF THE PUBLIC ELECTRICITY TRANSMISSION GRIDS, APPLICABLE AS AT 1 AUGUST 2021

5.1 Tariff rules

5.1.1 Definitions

For the application of these rules, the terms below have the following meanings.

5.1.1.1 Absorption of reactive power

Transmission of reactive power through the connection point aimed at supplying the public electricity grid user.

5.1.1.2 Power supplies

If a user is connected to the public grid(s) by several power supplies, the main, complementary and back-up power source(s) should be identified in a contract with the operator(s) of the public system(s) to which they are connected.

5.1.1.2.1 Main power supply(ies)

A user's main power supply or supplies must ensure that the user is supplied with their subscribed withdrawal capacity and/or the maximum injection capacity agreed under the normal operating conditions of the user's electrical equipment. Normal operating conditions are contractually agreed on between the user and the operator(s) of the public network(s) to which they are connected, in compliance with the quality commitments included in the corresponding access contract(s).

For the HTB 3 voltage level, a user's main power supply or supplies must ensure that the user is supplied with their subscribed withdrawal capacity and/or the maximum injection capacity agreed on under the normal operating conditions of the user's electrical equipment.

5.1.1.2.2 Backup power supply

A user's power supply is a back-up power supply if it is a live circuit that is only used for the transfer of power between the public grid and the installations of one or more users in the event of the unavailability of all or part of their main and complementary power supplies.

The dedicated part of a back-up power supply is the part of the public grids receiving only flows destined for one or more connection points of one or more back-up power supplies of this user or another user.

The flows taken into account to establish the dedicated part of back-up power supplies are those falling within the normal operating conditions contractually agreed on with the operator(s) of the public system to which they are connected in the event of the unavailability of all or part of their other power supplies, electrical installations of the user or users, given the topology of the public grids and regardless of the operating manoeuvres that may be carried out by their operators.

5.1.1.2.3 Complementary power supply

A user's power sources which are neither main power supplies nor back-up power supplies are considered as this user's complementary power supplies.

The dedicated part of a complementary power supply is the part of the public grids receiving only flows originating from or destined for one or more connection points of one or more complementary power supplies of this user.

The flows taken into account to establish the dedicated part of complementary power supplies are those falling within the normal operating conditions of the user's electrical installations contractually agreed on with the operator(s) of the public system(s) to which they are connected, given the topology of the public grids and regardless of the operating manoeuvres that may be carried out by their operators.

5.1.1.3 Cell

A cell is a set of electrical switchgears installed in a power substation and which consists of a main switching device (normally a circuit breaker), one or more isolating switches, voltage and current transformers and protection devices.

5.1.1.4 Grid access contract

The grid access contract is the contract referred to in articles L. 111-91 to L. 111-94 of the French energy code, which defines the technical, legal, and financial terms for user access to a public transmission or distribution grid to withdraw and/or inject electrical power. It is signed with the public system operator either by the user or by the supplier on their behalf.

5.1.1.5 Measurement curve

A measurement curve is a set of average values stamped with the hour and date for a variable measured over consecutive integration periods of the same duration. The load curve is a curve measuring the active energy with-drawn.

Integration periods are consecutive time intervals of the same duration during which average values of an electrical variable varying over time are calculated. When the present rules state that the variables are calculated per inte-gration period, the value of these variables is brought for each integration period to their average value during this period.

5.1.1.6 Metering system

The metering system is composed of all of the active and/or reactive power meters at a given metering point, cabi-nets, associated boxes and panels, as well as, as the case may be, the following specific additional equipment: synchronisation devices, communication interfaces for reading meters and terminals.

5.1.1.7 Voltage range

The AC voltage levels of the public transmission and distribution grids are defined in the table below:

Table 35 :The AC voltage levels of the public transmission and distribution grids

<table>
<tr><th>Connection voltage (U_n)</th><th colspan="3">Voltage level</th></tr>
<tr><td>$U_n \leq 1$ kV</td><td colspan="2">Low voltage (LV)</td><td>Low voltage level</td></tr>
<tr><td>1 kV < $U_n \leq 40$ kV</td><td>HTA 1</td><td rowspan="2">Medium voltage level</td><td rowspan="5">High voltage level</td></tr>
<tr><td>40 kV < $U_n \leq 50$ kV</td><td>HTA 2</td></tr>
<tr><td>50 kV < $U_n \leq 130$ kV</td><td>HTB 1</td><td rowspan="3">High voltage level</td></tr>
<tr><td>130 kV < $U_n \leq 350$ kV</td><td>HTB 2</td></tr>
<tr><td>350 kV < $U_n \leq 500$ kV</td><td>HTB 3</td></tr>
</table>

The tariffs applicable to users connected to the public grids at the HTA 2 voltage level are those of the HTB 1 voltage level. In all of the present rules, the tariffs applicable to users connected to public HTA 1 grid lines are termed HTA voltage level tariffs.

5.1.1.8 Supply of reactive power

Transmission of reactive power through the connection point aimed at supplying the public electricity grid user.

5.1.1.9 Active power injection

Transmission of active power through the connection point aimed at supplying the public electricity grid user.

5.1.1.10 Busbar

Three-phase set of three metallic bars or three conductors, each making up a set of points with equal voltage, common to each phase of a three-phase system. Buses are used to connect equipment together (devices, lines, wires). A busbar is not an electrical line (as defined below) for the purpose of these tariff rules.

5.1.1.11 Electrical line

An electrical line is composed of a circuit, a set of conductors and, as the case may be, an overhead earth wire.

However, when a transformer and a busbar are situated within the same substation or within two adjoining substations, the circuit connecting the transformer to the busbar is not an electrical line for the purposes of the present tariff rules, but is an integral part of the transformers.

5.1.1.12 Transformers

Transformers are devices located at the interface between two different voltage ranges on public electricity grids.

5.1.1.13 Connection points

A user's connection point(s) on the public grid coincide(s) with the ownership limit between the user's electrical equipment and the public grid' electrical equipment, generally corresponding to the boundary of the electrical equipment, materialised by a disconnecting device. Disconnecting device refers to a device installed in a power grid able to interrupt non-zero current flows circulating between the two extremities of the device.

For the application of the present rules, for a user having several connection points in the public grids, it is considered that all or part of these points are combined, if under the normal operating conditions of the user's electrical equipment contractually agreed on with the public system operator(s), they are connected by this user's electrical equipment to the connection voltage.

5.1.1.14 Time category

For all tariffs for the use of the public electricity grids, the time category is the set of times in the year during which the same tariff coefficients apply.

5.1.1.15 Active power (P)

Active power P refers to the average energy flow at a steady state at any point of the electricity grid.

5.1.1.16 Apparent power (S)

Apparent power S represents the amplitude of the instantaneous power signal at any point of the electricity grid.

5.1.1.17 Reactive power (Q) and reactive energy

Reactive power Q is equal to active power multiplied by the tg φ ratio.

Reactive energy refers to the integral of reactive power Q over a specified time period. Reactive energy is stored in the form of an electromagnetic field in the electricity grid environment, but is not consumed by users.

5.1.1.18 Phi tangent (tg φ) ratio

The phi tangent (tg φ) ratio measures, at any point of the electricity grid, the phase displacement of voltage and current signals. The tg φ ratio is an important parameter for the operation and safety of the electricity grid.

5.1.1.19 Withdrawal of active power

Transmission of active electrical energy through the connection point to supply the public electricity grid user.

5.1.1.20 User

A user of a public transmission system is any natural person or establishment of a legal person, including public system operator(s), directly supplying this public grid or directly served by this grid. Interconnection circuits are not considered users under the present rules.

5.1.2 Tariff structure

The tariffs below exclude all deductions and taxes applicable to the use of the public electricity networks.

At each connection point, the tariff paid annually for the use of a public electricity grid is the sum of:

- the annual management component(s) (CG);
- the annual metering component(s) (CC);
- the annual injection component (CI);
- the annual withdrawal component (CS);
- the monthly components for subscribed capacity overruns (CMDPS);
- the annual component for complementary and back-up power supplies (CACS);
- the component for conventional grouping of connection points (CR);
- for public grid operators, the annual component for transformer use (CT), compensation for operating lines at the same voltage as the upstream public grid and peak load shaving in extreme cold weather;
- the annual component for sporadic scheduled overruns (CDPP);
- the annual reactive energy component (CER).

These components are applied notwithstanding any provision to the contrary in specifications, franchise agreements and contracts, especially those concerning the billing of operating, maintenance and renewal costs.

The energy to be taken into account to calculate the annual injection and withdrawal components at each connection point is the energy corresponding to the physical flow at the connection point in question, measured for each integration period by the metering system contractually agreed on.

The grid access contract specifies the user's connection point(s) in the public grid concerned and the tariff(s) applied. For each connection point, it also specifies the connection voltage level, the metering system used, and for the HTB 1 and HTB 2 voltage ranges, the subscribed capacity, and for the HTB 3 voltage level, the maximum withdrawal power.

The tariff version, as the case may be, the capacity subscribed, are defined for a period of 12 consecutive months termed "subscription period".

5.2 Tariffs for the use of the public electricity transmission grid

5.2.1 Tariffs as at 1 August 2021

5.2.1.1 Annual management component (CG)

The annual management component in the grid access contract covers the management costs for user files, physical and telephone reception of users, billing and collection.

The annual management component a_1 is determined for each connection point of one or more main power supplies and for each access contract, according to the table below:

Table 36 :Annual management component

$a_1(€/year)$ / contract	Grid access contract
HTB	9,404.04

5.2.1.2 Annual metering component (CC)

The annual metering component relating to the metering devices owned by public system operators or authorities organising public electricity distribution, cover the costs of metering, control and the transmission of metering data (these are transmitted to the user or a third party authorised by it at a minimum frequency defined in the table below), as well as repair costs and, as the case may be, the cost of leasing metering devices.

The annual metering component is established for each metering system depending on the ownership of the metering system.

Variables measured by the user's measuring and control equipment must enable the calculation of the annual components in the tariff for the use of the public grids.

Table 37 :Annual metering component

Voltage level	Minimum transmission frequency	Ownership of the metering system	Annual metering component (€/year)
HTB	Weekly	Public system operator	3,095.28
HTB	Weekly	User	555.72

5.2.1.3 Annual injection component (CI)

The annual injection component is established at each connection point, depending on the active energy injected in the public grid, according to table below:

Table 38 :Annual injection component

Voltage range	c€/MWh
HTB 3	23
HTB 2	23
HTB 1	0

5.2.1.4 Annual withdrawal components (CS) and monthly components for subscribed power overruns (CMDPS)

5.2.1.4.1 Tariff for the HTB 3 voltage level

At each connection point to the HTB 3 voltage level, the annual withdrawal component is established according to the following formula:

$$CS = c.E$$

Where E corresponds to the active energy withdrawn during the consecutive 12-month period in question.

The value of the coefficient c is indicated in the table below:

Table 39 :Annual withdrawal component – HTB 3 voltage level

Voltage level	c (€c/kWh)
HTB 3	0.33

5.2.1.4.2 Tariff for the HTB 2 voltage level

For each of their connection points in the HTB 2 voltage level, users choose, for each of the n time categories, subscribed capacity P_i in multiples of 1 kW, where i designates the time category (see tables 41 to 43). Whatever the value of i, subscribed capacity must be such that $P_{i+1} \geq P_i$.

At each of these connection points, the annual withdrawal component is established according to the following formula:

$$CS = b_1.P_1 + \sum_{i=2}^{5} b_i.(P_i - P_{i-1}) + \sum_{i=1}^{5} c_i.E_i + \sum_{12\ mois} CMDPS$$

- P_i designates the subscribed capacity for the time category i, expressed in kW;
- *Ei* designates the active energy withdrawn during the time category i, expressed in kWh;
- CMDPS designates the monthly component for overruns calculated as stated in section 3.2.4.2.

The time categories of the HTB 2 tariff are defined as follows:

- the high season includes the months of November to March;
- the low season includes the months of April to October;
- super peak times are set, from December to February inclusive, between 9:00 a.m. and 11:00 a.m. and between 6:00 p.m. and 8:00 p.m., from Monday to Friday inclusive, excluding holidays;
- peak times are set between 7:00 a.m. and 11:00 p.m., from Monday to Friday inclusive, excluding the peak times previously defined;
- the other times of the day are defined as off-peak times;
- Sundays, Saturdays and holidays are fully considered as off-peak times.

During the TURPE 6 period, the transmission system operator may update, according to geographic zone, the definition of low season, high season, off-peak times and peak times based on the operating conditions of the transmission network. However, the new definition shall comply with the following conditions:

- the high season shall necessarily include the months of December to February, and an additional sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods;
- Sundays, Saturdays and holidays shall be fully considered as off-peak times;
- the other 8 off-peak hours shall be consecutive or divided into two periods, considering as consecutive the hours 11.00 p.m. - 12.00 a.m. and 12.00 a.m. - 1.00 a.m.

In order to guarantee the readability of the tariff, all changes shall be subject to a prior consultation process within the committee of power transmission system users (CURTE). These new definitions shall be communicated to all persons that so request, and published on RTE's website.

To establish the annual withdrawal component in the HTB 2 voltage level, users choose one of the three tariff versions below:

- short use;
- medium use;
- long use.

The user keeps their tariff version for a minimum period of 12 months as from the date of subscription. At the end of this 12-month period, the user may change the tariff version at any time.

For the HTB 2 tariff, the b_i and c_i coefficients used for the short-, medium- and long-use tariffs are those in table 40, table 41 and table 42 respectively:

Table 40 :Annual withdrawal component – HTB 2 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	$b_1 = 1.43$	$b_2 = 1.37$	$b_3 = 1.35$	$b_4 = 1.28$	$b_5 = 1.05$
Energy-based coefficient (€c/kWh)	$c_1 = 1.29$	$c_2 = 0.88$	$c_3 = 0.85$	$c_4 = 0.67$	$c_5 = 0.54$

Table 41 :Annual withdrawal component – HTB 2 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	$b_1 = 4.42$	$b_2 = 4.24$	$b_3 = 4.16$	$b_4 = 3.43$	$b_5 = 2.42$
Energy-based coefficient (€c/kWh)	$c_1 = 1.09$	$c_2 = 0.85$	$c_3 = 0.65$	$c_4 = 0.51$	$c_5 = 0.34$

Table 42 :Annual withdrawal component – HTB 2 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	$b_1 = 11.92$	$b_2 = 11.44$	$b_3 = 9.40$	$b_4 = 7.17$	$b_5 = 3.87$
Energy-based coefficient (€c/kWh)	$c_1 = 0.78$	$c_2 = 0.61$	$c_3 = 0.45$	$c_4 = 0.31$	$c_5 = 0.25$

5.2.1.4.3 Tariff for the HTB 1 voltage level

For each of their connection points to the HTB 1 voltage level, users choose, for each of the n time categories of the tariff, subscribed capacity P_i in multiples of 1 kW, where i designates the time category. Whatever the value of i, subscribed capacity must be such that $P_{i+1} \geq P_i$.

At each of these connection points, the annual withdrawal component is established according to the following formula:

$$CS = b_1.P_1 + \sum_{i=2}^{5} b_i.(P_i - P_{i-1}) + \sum_{i=1}^{5} c_i.E_i + \sum_{12\ monts} CMDPS$$

- P_i designates the subscribed capacity for the time category i, expressed in kW;
- E_i designates the active energy withdrawn during the time category i, expressed in kWh.
- CMDPS designates the monthly component for overruns calculated as stated in section 5.2.1.4.4.

The time categories of the HTB 1 tariff are defined as follows:

- the high season includes the months of November to March;
- the low season includes the months of April to October;

- super peak times are set, from December to February inclusive, between 9:00 a.m. and 11:00 a.m. and between 6:00 p.m. and 8:00 p.m., from Monday to Friday inclusive, excluding holidays;
- peak times are set between 7:00 a.m. and 11:00 p.m., from Monday to Friday inclusive, excluding the peak times previously defined;
- the other times of the day are defined as off-peak times;
- Sundays, Saturdays and holidays are fully considered as off-peak times.

During the TURPE 6 period, the transmission system operator may update, according to geographic zone, the definition of low season, high season, off-peak times and peak times based on the operating conditions of the transmission network. However, the new definition shall comply with the following conditions:

- the high season shall necessarily include the months of December to February, and an additional sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods;
- Sundays, Saturdays and holidays shall be fully considered as off-peak times;
- the other 8 off-peak hours shall be consecutive or divided into two periods, considering as consecutive the hours 11.00 p.m. - 12.00 a.m. and 12.00 a.m. - 1.00 a.m.

In order to guarantee the readability of the tariff, all changes shall be subject to a prior consultation process within the committee of power transmission system users (CURTE). They shall be communicated to all persons that so request, and published on RTE's website.

To establish the annual withdrawal component in the HTB 1 voltage level, users choose one of the three tariff versions below:

- short use;
- medium use;
- long use.

The user keeps their tariff version for a minimum period of 12 months as from the date of subscription. At the end of this 12-month period, the user may change the tariff version at any time.

For the HTB 1 tariff, the b_i and c_i coefficients used for the short-, medium- and long-use tariffs are those in table 43, table 44 and table 45 respectively:

Table 43 :Annual withdrawal component – HTB 1 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	b_1 = 4.19	b_2 = 3.88	b_3 = 3.77	b_4 = 3.19	b_5 = 2.80
Energy-based coefficient (€c/kWh)	c_1 = 2.30	c_2 = 1.88	c_3 = 1.57	c_4 = 1.18	c_5 = 0.85

Table 44 :Annual withdrawal component – HTB 1 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	b_1 = 16.63	b_2 = 16.02	b_3 = 13.59	b_4 = 9.91	b_5 = 5.87
Energy-based coefficient (€c/kWh)	c_1 = 1.70	c_2 = 1.39	c_3 = 0.92	c_4 = 0.65	c_5 = 0.44

Table 45 :Annual withdrawal component – HTB 1 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient (€/kW/year)	b_1 = 32.17	b_2 = 30.99	b_3 = 24.86	b_4 = 17.49	b_5 = 9.94
Energy-based coefficient (€c/kWh)	c_1 = 1.24	c_2 = 0.95	c_3 = 0.60	c_4 = 0.41	c_5 = 0.21

5.2.1.4.4 Monthly components for subscribed capacity overruns (CMDPS) for the HTB 2 and HTB 1 voltage levels

Compared to the tariffs of previous periods, the CMDPS is maintained, but it is specified to make it applicable to situations changing during the month (modification by a user of their tariff version during the month, period of severe cold shorter than a full month during which a distribution grid operator can receive a reduction in their power over-runs).

For the HTB 2 and HTB 1 voltage levels, the components of subscribed capacity overruns are established each month based on the following formula, for each interconnection point:

$$CMDPS = \sum_{i=1}^{5} 0{,}04 * b_i * \sqrt{\sum_{j\ with\ P_j > PS_i} (P_j - PS_i)^2}$$

Where:

- i designates the time category;
- b_i is the capacity-based coefficient defined for the time category i and the tariff version selected, and depending on the voltage level;
- PS_i is the subscribed capacity for the time category i;
- j is the time period of 10 minutes;
- Pj is the average 10-minute active power in kW.

The subscribed capacity taken into account is that declared at least three working days before the measurement of the overrun by the user.

In the case of a change in tariff version during the month, the monthly amount due for overruns is billed by applying the formula below:

$$CMDPS = \sum_{i=1}^{5} 0{,}04 * \sqrt{b_i^2 \sum_{\substack{j\ before\ the\ chan\ in\ tariff\ version\ with \\ P_j > PS_i}} \left(P_j - PS_i\right)^2 + b'^2_i \sum_{\substack{j\ after\ the \\ chang\ in\ tariff\ version\ with \\ P_j > PS_i}} \left(P_j - PS_i\right)^2}$$

Where:

- b_i is the capacity-based coefficient for the time category i for the first tariff version;
- b'_i is the capacity-based coefficient for the time category i for the second tariff version.

If the user is a public distribution system operator (DSO), during peak load shaving in extreme cold weather, the overrun formula includes the coefficient specified in the general conditions of the DSO's transmission grid access contract.

5.2.1.4.5 Terms for the medication of subscribed capacity during a subscription period

The terms for the modification, by a user, of subscribed capacity during the subscription period are specified in the grid access contract. The terms of this contract specify, on the one hand, that a notice of three working days between the date of the request for subscribed capacity modification and the date of the effective change in subscribed capacity must be honoured by the user, and on the other hand, that a change in subscribed capacity applies only to the future.

5.2.1.5 Annual component for complementary and back-up power supplies (CACS)

Complementary and back-up power supplies established upon the request of users are billed according to the terms described below. The annual component for complementary and back-up power supplies (CACS) is equal to the sum of these components.

5.2.1.5.1 Complementary power supplies

The parts dedicated to a user's complementary power supplies are subject to a charge for the electrical equipment of which they are composed. This billing is based on the length of these dedicated parts according to the following scale:

Table 46 :Complementary power supplies

Voltage level	Cells (€/cell/year)	Lines (€/km/year)
HTB 3	106,930.88	10,135.99
HTB 2	64,488.15	Overhead lines: 6,462.01 Underground lines: 32,308.87
HTB 1	33,496.46	Overhead lines: 3,834.42 Underground lines: 7,668.84

5.2.1.5.2 Backup power supplies

The parts dedicated to a user's backup power supplies are subject to a charge for the electrical equipment of which they are composed. This billing is based on the length of these dedicated parts according to the price scale in table 46 above. Subscribed capacity for backup power supplies is less than or equal to the subscribed capacity for main power supplies.

When a backup power supply is shared among several users, the billing of the parts dedicated to backup power supplies and receiving flows destined for the connection points of several users is shared among these users in proportion to the capacity they have subscribed for this backup power supply.

When the backup power supply is connected at the same voltage level as the main power supply and, at the request of the user, it is connected to a public grid transformer different to the transformer used for their main power supply, the billing of the dedicated parts of backup power supplies is equal to the sum of the component resulting from the application of the price scale in table 47 above and the component established based on the price scale in table 47 below, corresponding to the pricing of the booking of transformer power:

Table 47 :Backup power suppliers – Power booking

Supply voltage level	€/kW/year or €/kVA/year
HTB 2	1.55
HTB 1	2.98

When the backup power supply is connected to a voltage level different to that of the main power supply, the annual billing of the backup power supply(ies) is equal to the sum of the component resulting from the application of the price scale in the table above and the component established according to the price scale in table 48 below, corresponding to the pricing of the public electricity grid enabling backup in a lower voltage level.

When the backup power supply, which is connected to a voltage level different to that of the main power supply, is equipped with a meter measuring active power overruns compared to the backup capacity subscribed for each integration period of 10 minutes, the monthly component for subscribed capacity overruns for the backup supply is set each month according to the terms below:

$$CMDPS = \alpha.\sqrt{\sum(\Delta P^2)}$$

Table 48 :Backup power supplies – Pricing of the public grid enabling backup

Main supply voltage level	Backup supply voltage level	Fixed bonus (€/kW/year)	Power portion (€c/kWh)	α (€c/kW)
HTB 3	HTB 2	7,41	0,77	31,39
	HTB 1	5.45	1.31	23.25
HTB 2	HTB 1	1.59	1.31	6.98

5.2.1.6 Grouping component (CR)

A user connected to the same public network with several connection points in the same HTB voltage level and equipped with load curve meters for each of these points can, if they so wish, benefit from the conventional grouping of all or part of these points for the application of the tariffs described in sections 5.2.1.3 and 5.2.1.4, through payment of a grouping component. In this case, the annual injection component (CI), annual withdrawal component (CS), monthly components for subscribed capacity overruns (CMDPS), annual component for sporadic scheduled overruns (CDPP) and annual reactive energy component (CER) are defined based on the sum of the physical flows measured at the connection points concerned. The possibility of grouping the connection points in the same public grid is limited to the scope of the same distribution concession for public distribution system operators and to the same site for other users.

Grouping of the reactive energy flows of connection points is only possible in cases where these connection points meet the conditions stated in the reference technical documentation of the public electricity system operator.

The grouping component (CR) is established according to the length of the existing public electricity grid enabling this grouping, independently of the operating conditions and the flow capacity available in the grids enabling this grouping. The amount of this component is calculated using the following formula, based on $P_{grouped\ subscribed}$[65],

[65] For the HTB 3 voltage level, the power considered corresponds to the maximum hourly withdrawal power over the previous 12 months.

the subscribed capacity for all points grouped conventionally and L, the smallest total length of the electrical infrastructure of the public grid concerned physically enabling the grouping.

$$CR = L.k.P_{grouped\ subscribed}$$

The coefficient k is defined in the table below:

Table 49 :Grouping component

Supply voltage level	k (€c/kW/km/year)
HTB 3	5,81
HTB 2	Overhead lines: 15.12 Underground lines: 58.12
HTB 1	Overhead lines: 76.73 Underground lines: 134.86

5.2.1.7 Specific provisions for annual withdrawal components (CS) of public distribution system operators

5.2.1.7.1 Annual component for transformer use (CT)

A public distribution system operator that operates one or more overhead or underground lines, downstream of their connection point, in the same voltage level as that downstream of the transformer to which they are directly connected, without an intermediate line upstream of their connection point, can apply upon request for the annual withdrawal component (CS) applicable to the voltage level just above that applicable to the connection point.

The operator must in this case pay an annual component for transformer use, reflecting the cost of transformers and cells. This component is calculated using the following formula, based on the grouped subscribed capacity $P_{grouped\ subscribed}$.

$$CT = k.P_{grouped\ subscribed}$$

The k coefficient used is that defined in the table below:

Table 50 :Annual component for transformer use

Voltage level of the connection point	Voltage level of the pricing applied	k (€/kW/year)
HTB 2	HTB 3[66]	1.82
HTB 1 or HTA 2	HTB 2	3.91
HTA 1	HTB 1	6.91

This arrangement can be combined with that of tariff grouping, according to the terms in section 5.2.1.6. In this case, pricing for the voltage range above each connection point is applied first followed by the tariff grouping mentioned above.

[66] For the HTB 3 voltage range, the power considered corresponds to the maximum hourly withdrawal power over the previous 12 months.

5.2.1.7.2 Compensation for operating lines at the same voltage as the upstream public grid

A public distribution system operator that operates lines downstream of their connection point in the same voltage level as the lines upstream of this connection point, benefits from this compensation if the pricing that is applied to the connection point in question is that of the voltage level of this point.

In this case, the annual withdrawal component (CS) for this connection point is calculated using the following formula:

$$CS = \frac{I_2}{I_1 + I_2}.CS_{\mathrm{N}} + \frac{I_1}{I_1 + I_2}.(CS_{\mathrm{N+1}} + CT_{\mathrm{N/N+1}})$$

With:

- I_1 the total length of the line(s) operated in voltage level N by the public distribution system operator;
- I_2 the total length of the line(s) operated in voltage level N by the public distribution system operator to which they are connected which is absolutely necessary for linking their connection point to this operator's voltage transformer(s) to guarantee the subscribed capacity in normal operating conditions defined in the reference technical documentation of the operator of the public grid upstream
- $CT_{\mathrm{N/N+1}}$ is the annual component for transformer use between the voltage ranges N+1 and N defined in section 5.2.1.7.1.

5.2.1.7.3 Peak shaving in extreme cold weather

During each period of severe cold, as defined below in hourly increments, the distribution system operator can receive a reduction for its subscribed capacity overruns only during this period and the 24 hours following the period of application of this clause.

A period of severe cold corresponds to the hours during which, at a weather station and in hourly increments, the minimum temperature recorded is lower than the reference minimum local temperature, defined at each weather station by the 30th monthly minimum temperature in 30 years.

This provision is applied in compliance with transparent and non-discriminatory terms.

5.2.1.8 Annual component for sporadic scheduled overruns (CDDP) for the HTB 2 and HTB 1 voltage levels

For sporadic scheduled overruns for work notified to the public system operator in advance, a user can request the application of a specific price scale for the calculation of their component for subscribed capacity overruns related to this connection point, provided that one of its connection points, not exclusively supplied or served by one or more back-up power supplies, is equipped with a load curve meter and connected to the HTB 2 or HTB 1 voltage levels.

In this case, during the period during which this price scale is applied, subscribed capacity overruns are subject to the following billing method which replaces the billing of subscribed capacity overruns defined in section 5.2.1.4.4. The power overruns compared to subscribed capacity ΔP are calculated for integration periods of 10 minutes.

The formula is as follows with b_i the capacity-based coefficient of the time category and the corresponding tariff version:

$$CDPP = \alpha.b_i.\sum \Delta P$$

The α factor applicable is defined in the table below:

Table 51 :Annual component for sporadic scheduled overruns for the HTB 2 and HTB 1 voltage levels

Voltage level	α
HTB 2	0.000143
HTB 1	0.000090

The elements to be provided by users to support their request for the application of the specific price scale for the calculation of the component for subscribed capacity overruns and the conditions under which the public transmission system operator can check for consistency of these requests are specified in the grid access contract. When such a request comes from a public distribution system operator and is the consequence of a request by a user connected to its grid, the public distribution system operator passes the aforementioned elements on to the upstream public system operator, and supplies the user's maximum power request which will be subtracted from the subscribed capacity overruns of the public distribution system operator and billed according to the terms applicable to sporadic scheduled overruns.

The application of this provision is limited for each connection point to a maximum of once per calendar year, for use corresponding to the period of work and a maximum of 14 consecutive days. For the breakdown of the number of applications of this provision per connection point, the applications made upon the request of public distribution system operators are not taken into account when they are the consequence of a request by a user connected to their network. Days which have not been used cannot be carried over.

The public transmission system operator may refuse or suspend the application of this provision to a user, due to the operating constraints it forecasts in the public grid that it operates. This refusal or suspension shall be justified and notified to CRE at the same time. The transmission system operator shall transmit annually a report of the sporadic scheduled overruns it has authorised.

Users connected to the HTA 2 voltage levels, billed according to the TURPE HTB tariffs in accordance with all of the tariff rules applicable, cannot benefit from this provision.

5.2.1.9 Load transfer

RTE may suspend the transmission network access service to enable maintenance, renewal, development and repair of transmission network infrastructure and may therefore, at its initiative, transfer all or part of a user's withdrawal to one or more of its supplies (main, complementary or backup).

If the withdrawal transfer concerns main or complementary supplies, the subscribed capacity overruns observed during the period of load transfer in these supplies are not taken into account in the calculation of the monthly component for subscribed capacity overruns.

If the transfer concerns a backup supply, the quantities of energy withdrawn by the backup supply are billed at the tariff for main supply and only overruns above the subscribed capacity for main supply are billed.

When the load transfer concerns a supply operated by a distribution system operator, RTE pays a financial compensation to this DSO according to the terms specified in the DSO grid access contract.

The terms for suspending main supply are specified in the grid access contract.

This provision is applied in compliance with transparent and non-discriminatory terms.

Users connected to the HTA 2 voltage level, billed according to the TURPE HTB tariffs in accordance with all of the tariff rules applicable, cannot benefit from this provision.

5.2.1.10 Annual reactive energy component (CER)

In the absence of metering systems recording physical flows of reactive energy, public system operators can provide for transparent and non-discriminatory methods for estimating these flows in their reference technical documentation.

The provisions in sections 5.2.1.10.1 below do not apply to the connection points located at the interface between two public electricity grids.

5.2.1.10.1 General principles

Grid reactive energy absorbed at a connection point is billed only from Monday to Saturday between 6.00 a.m. and 10.00 p.m. during the period from 1 November to 31 March, at each hour, when the tg φ_{max} set as 0.4 is surpassed.

The reactive energy supplied to the grid at a connection point is billed only during the period from 1 April to 31 October, at each our, when:

- the physical active energy flows are injection flows and the reactive energy supplied is higher than a Q_f threshold (in absolute value);

- the physical active energy flows are withdrawal flows lower than a P_f threshold (percentage of subscribed capacity contracted in access contracts), and the reactive energy supplied is higher than a Q_f threshold (in absolute value).

The P_f and Q_f thresholds are explained in the reference technical documentation of the transmission system operator.

Hourly billing is applied to calculate unit overruns in each billing zone. The costs for overruns are defined in Tableau 52 below:

Table 52 :Annual reactive energy component

Unit cost of the overrun	€/Mvar.h
Billing zone for the reactive energy absorbed by the user	10.3
Billing zone for the reactive energy supplied by the user	0.9

When the physical active energy flows at a connection point are injection flows, the equipment is voltage controlled and the user does not benefit from a contract as provided by article L. 321-11 of the energy code, the user undertakes to maintain the voltage at the connection point of its equipment within a range determined by the public system operator and set according to the rules published in the reference technical documentation of the public system operator to which the user is connected. Should the voltage stray from the agreed range, the user is billed according to table 52 above for the difference between the reactive energy that its equipment has effectively supplied or absorbed and the reactive energy that it should have supplied or absorbed to maintain the voltage within the range of its operating agreement, in the limit of its design capacities defined by diagrams [U, Q] of its connection agreement. These elements are established according to the rules published in the reference technical documentation of the public transmission system operator.

When the physical active energy flows at a connection point are injection flows, the equipment is voltage controlled, and the user has a contract as provided for by article L. 321-11 of the energy code, the user takes part in voltage control based on the voltage ancillary services rules defined in the reference technical documentation of the system operator. In this instance, the user is not subject to the reactive energy pricing defined in the present section.

On an experimental basis, for a maximum period of three years, and by mutual agreement, the public transmission system operator and the user may choose to define billing principles different from the principles defined in this section in order to test innovative means of improving the management of reactive energy at the interface between grids.

5.2.1.10.2 Specific provisions for the annual reactive energy component between two public electricity system operators

At each connection point they share, the public distribution system operators agree, by contract with the public transmission system operator, on the quantity of reactive energy they exchange, fixed according to the active energy transmitted.

The reactive energy absorbed by a public distribution system operator is billed only from Monday to Saturday between 6.00 a.m. and 10.00 p.m. during the period from 1 November to 31 March and when the conditions below are met:

- the tg φ_{max} value contracted with the public transmission system operator is surpassed;
- the physical active energy flows are withdrawal flows higher than a P_a threshold (percentage of subscribed capacity contracted in access contracts).

The reactive energy supplied by a public distribution system operator is billed for the whole year, at each hour, when:

- the physical active energy flows are injection flows and the reactive energy supplied is higher than a Q_f threshold (in absolute value);
- the physical active energy flows are withdrawal flows lower than a P_f threshold (percentage of subscribed capacity contracted in access contracts), and the reactive energy supplied is higher than a Q_f threshold (in absolute value).

The P_a, P_f, Q_f thresholds and the way in which $tg\ \varphi_{max}$ is contracted are explained in the reference technical documentation of the transmission operator. These rules and the terms for updating them take into account, on the one hand, the possibilities reasonably available to the public distribution system operator for controlling reactive energy, and on the other hand, the voltage constraints identified, over a five to ten-year timeframe, by the public transmission system operator.

Hourly billing is applied to calculate unit overruns in each billing zone. The costs of overruns are defined in table 53 below:

Table 53 :Annual component for reactive energy between two public electricity system operators

Unit cost of the overrun	€/Mvar.h
Billing zone for the reactive energy absorbed	3.05
Billing zone for the reactive energy supplied	0.53

The same rules apply to the connection point between two public distribution system operators when one of them operates an HTB voltage level at the interface between the two grids. In this case, the public distribution system operator operating the HTB voltage level specifies the rules in its reference technical documentation based on the terms described in this section.

On an experimental basis, and by mutual agreement, the public system operators may choose to define billing principles different to the principles described in this section in order to test innovative ways of improving the management of reactive energy at the interface between grids.

Users connected to the HTA voltage level, billed according to the TURPE HTB tariffs in accordance with all of the tariff rules applicable, cannot benefit from this provision.

5.2.1.11 Transitional provisions for the implementation of the present tariff rules

Between 1 August and 30 November of the years 2021, 2022, 2023 and 2024, users may, for each connection point, modify their tariff versions without having to comply with the rule of 12 consecutive months since their previous selection. This provision can be activated only once (apart from the change made upon the entry into effect of the present tariff rules) during the TURPE 6 HTB period, taking effect on the date the change is made.

The rules applying to modifications to subscribed capacity, and in particular the principle of a definition of subscribed capacity at the start of a period of 12 consecutive months for all of this period, are not modified.

5.2.2 Tariffs applicable as from 1 August 2022

5.2.2.1 Change in tariffs

Each year *N* as from 2022, the tariff coefficients, excluding the coefficients for the withdrawal component and the injection component, applicable from 1 August *N* to 31 July *N+1*, are the product:

- of the tariff coefficients applicable from 1 August 2021 to 31 July 2022 defined in section 5.2.1;
- and a coefficient Y_N corresponding to the cumulated tariff change of years 2022 to *N*.

Each year *N* as from 2022, the tariff coefficients of the annual withdrawal component, applicable from 1 August *N* to 30 July *N+1*, are updated to take into account:

- on the one hand, the gradual implementation of the structure developments decided in the present deliberation;
- on the other hand, the annual update in the tariff level.

Therefore, the tariff coefficients of the annual withdrawal component applicable are the product of:

- the tariff coefficients of the reference tariffs of year *N*, defined in section 5.2.2.2;
- and a coefficient Y_N corresponding to the cumulated tariff change of years 2022 to *N*.

The coefficient Y_N is defined as follows, rounded off to four decimal points (0.0001):

$$Y_N = Y_{N-1} \times (1 + Z_N)$$

- $Y_{2021} = 1$.

The Z_N annual update coefficient of year *N* is defined as:

$$Z_N = IPC_N + K_N + X$$

- Z_N: annual update coefficient as at 1 August of year *N*;
- IPC_N: forecasted inflation rate for year *N* taken into account in the draft finance law of year *N*;
- K_N: updated coefficient coming from the reconciliation of the CRCP balance of year *N-1*, within the range of -2% and +2%;
- X: the annual update factor for the tariffs, equal to 0.49%;

The rounding off rules are as follows:

- the annual update coefficients Z_N are rounded off to the nearest one hundredth percent;
- the annual update coefficients cumulated between 1 August 2021 and 1 August of year *N* are not rounded off;
- after application of the cumulated annual update coefficients, the level of the annual management and metering components, as well as of parts proportional to subscribed capacity, is rounded off to the nearest euro cent divisible by 12;
- the level of the other components (except the injection component) is rounded off the nearest hundredth of the unit in which it is expressed.

5.2.2.2 Reference tariffs applicable for the years 2022, 2023 and 2024

5.2.2.2.1 HTB 3 reference tariff

HTB 3 reference tariff as at 1 August 2022

Table 54 :Annual withdrawal component – HTB 3 voltage level

Voltage level	c (€c/kWh)
HTB 3	0.33

HTB 3 reference tariff as at 1 August 2023

Table 55 :Annual withdrawal component – HTB 3 voltage level

Voltage lvel	c (€c/kWh)
HTB 3	0.33

HTB 3 reference tariff as at 1 August 2024

Table 56 :Annual withdrawal component – HTB 3 voltage level

Voltage level	c (€c/kWh)
HTB 3	0.33

5.2.2.2.2 HTB 2 reference tariff

HTB 2 reference tariff as at 1 August 2022

Table 57 :Annual withdrawal component – HTB 2 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	1,9612	1,9209	1,9109	1,8706	1,7097
Energy-based coefficient c_i (€c/kWh)	1,1666	0,8549	0,8046	0,6336	0,5029

Table 58 :Annual withdrawal component – HTB 2 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	4,1737	4,0430	3,9022	3,3390	2,6350
Energy-based coefficient c_i (€c/kWh)	0,9755	0,8046	0,6437	0,5129	0,3721

Table 59 :Annual withdrawal component – HTB 2 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	11,2640	10,7813	8,7397	6,5271	3,8720
Energy-based coefficient c_i (€c/kWh)	0,6939	0,5733	0,4526	0,3520	0,2917

HTB 2 reference tariff as at 1 August 2023

Table 60 :Annual withdrawal component – HTB 2 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	2,4919	2,4719	2,4619	2,4419	2,3718
Energy-based coefficient c_i (€c/kWh)	1,0408	0,8407	0,7606	0,5905	0,4804

Table 61 :Annual withdrawal component – HTB 2 voltage level – Medium-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	3,9631	3,8530	3,6628	3,2725	2,8622
Energy-based coefficient c_i (€c/kWh)	0,8707	0,7606	0,6405	0,5104	0,4103

Table 62 :Annual withdrawal component – HTB 2 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	10,6182	10,1579	8,1163	5,8946	3,8930
Energy-based coefficient c_i (€c/kWh)	0,6105	0,5404	0,4604	0,3903	0,3303

HTB 2 reference tariff as at 1 August 2024

Table 63 :Annual withdrawal component – HTB 2 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	3,0262	3,0262	3,0262	3,0262	3,0262
Energy-based coefficient c_i (€c/kWh)	0,9059	0,8163	0,7167	0,5575	0,4480

Table 64 :Annual withdrawal component – HTB 2 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	3,7429	3,6732	3,4243	3,2153	3,0859
Energy-based coefficient c_i (€c/kWh)	0,7565	0,7068	0,6371	0,5176	0,4380

Table 65 :Annual withdrawal component – HTB 2 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	9,9943	9,5464	7,4957	5,2858	3,9022
Energy-based coefficient c_i (€c/kWh)	0,5375	0,5077	0,4679	0,4280	0,3783

5.2.2.2.3 HTB 1 reference tariff

HTB 1 reference tariff as at 1 August 2022

Table 66 :Annual withdrawal component – HTB 1 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	5,8921	5,6914	5,6111	5,2297	4,9687
Energy-based coefficient c_i (€c/kWh)	2,1782	1,7968	1,5257	1,0841	0,7729

Table 67 :Annual withdrawal component – HTB 1 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	14,6651	14,2034	12,4167	9,8269	7,0465
Energy-based coefficient c_i (€c/kWh)	1,6361	1,3752	1,0138	0,7026	0,5019

Table 68 :Annual withdrawal component – HTB 1 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	32,6226	31,3177	25,0140	17,3552	10,8006
Energy-based coefficient c_i (€c/kWh)	1,0339	0,8331	0,5722	0,4316	0,2710

HTB 1 reference tariff as at 1 August 2023

Table 69 :Annual withdrawal component – HTB 1 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	7,6187	7,5085	7,4685	7,2783	7,1481
Energy-based coefficient c_i (€c/kWh)	2,0724	1,7220	1,4717	0,9911	0,7108

Table 70 :Annual withdrawal component – HTB 1 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	12,7545	12,4441	11,2728	9,7611	8,2494
Energy-based coefficient c_i (€c/kWh)	1,5718	1,3716	1,1113	0,7509	0,5506

Table 71 :Annual withdrawal component – HTB 1 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	33,1877	31,7461	25,2387	17,2796	11,6933
Energy-based coefficient c_i (€c/kWh)	0,8309	0,7208	0,5406	0,4605	0,3304

HTB 1 reference tariff as at 1 August 2024

Table 72 :Annual withdrawal component – HTB 1 voltage level – Short-use version

Short-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	9,3412	9,3412	9,3412	9,3412	9,3412
Energy-based coefficient c_i (€c/kWh)	1,9703	1,6602	1,4202	0,9101	0,6401

Table 73 :Annual withdrawal component – HTB 1 voltage level – Medium-use version

Medium-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	10,8814	10,6914	10,1514	9,7313	9,4613
Energy-based coefficient c_i (€c/kWh)	1,5102	1,3602	1,2202	0,8001	0,6001

Table 74 :Annual withdrawal component – HTB 1 voltage level – Long-use version

Long-use version	Super peak times (i = 1)	High season peak times (i = 2)	High season off-peak times (i = 3)	Low season peak times (i = 4)	Low season off-peak times (i = 5)
Capacity-based coefficient b_i (€/kW/year)	33,8245	32,2343	25,5234	17,2223	12,6017
Energy-based coefficient c_i (€c/kWh)	0,6301	0,6101	0,5201	0,4801	0,4001

ANNEX 1: REFERENCES FOR THE ANNUAL UPDATE OF THE TARIFFS FOR THE USE OF THE PUBLIC ELECTRICITY GRIDS IN THE HTB VOLTAGE RANGE AS FROM 1 AUGUST 2022

1. CALCULATION AND RECONCILIATION OF THE CRCP

RTE's CRCP balance, as at 1 January 2021, is equal to the difference between the definitive amount of the CRCP balance of TURPE 5 HTB and the provisional amount, equal to €5.8 million, taken into account to prepare TURPE 6 HTB.

For each year *N*, as from the year 2021, the definitive balance of the CRCP as at 31 December of year *N* is calculated as the sum:

- of the forecast CRCP balance as at 31 December of year *N* defined as the sum of the CRCP balance as at 1 January of year *N* and the difference for year *N* between the forecast allowed revenue adjusted for inflation and the forecast revenues adopted in the present deliberation, re-evaluated based on actual changes already applied to the tariffs;
- and the difference, for year *N*, between:
    - the difference between the definitive allowed revenue, as defined hereafter, and the forecast allowed revenue adjusted for inflation;
    - the difference between the tariff revenues received by RTE and the forecast tariff revenues re-evaluated based on actual changes already applied to the tariffs.

The CRCP balance as at 1 January of year *N+1* is obtained by discounting the CRCP balance as at 31 December of year *N* at the risk-free rate in effect of 1.7%.

The CRCP balance at the end of the tariff period also takes into account the amounts relating to the incentive regulation for research and development (R&D) expenses, the mechanism for asset management and the incentive regulation for controlling and prioritising investment expenses.

The tariff update as at 1 August of year *N* takes into account a coefficient K_N, which aims to:

- close the reconciliations generated by the K coefficients applied the previous years;
- reconcile, by 31 July of year *N*+1, the CRCP balance of 1 January of year *N*.

The coefficient K_N is capped at +/-2%.

2. REFERENCE VALUES FOR THE CALCULATION OF THE DEFINITIVE ALLOWED REVENUE

For each year *N* as from the year 2021, the definitive allowed revenue is equal:

- to the sum of the amounts adopted for the following expense items:
    - forecast net incentive-backed operating expenses;
    - forecast "*non-grid*" incentive-backed normative capital expenses;
    - other normative capital expenses;
    - expenses for loss compensation;
    - expenses for the constitution and reconstitution of balancing reserves;
    - expenses for international and national congestion;
    - expenses for the interruptibility mechanism;
    - stranded costs (net book value of demolished assets and studies and work not followed through);
    - compensation paid by RTE to the DSOs for long outages resulting from the public transmission grid;
    - costs of studies not followed through relating to the abandonment of large investment projects when these studies have been approved by CRE;
    - rebalancing costs and any penalties paid by capacity mechanism actors;

  - the costs of contracting flexibility procured for the purpose of congestion management within the framework of experimental calls for tenders to be conducted by RTE in accordance with the roadmap validated by CRE during the examination of the TYNDP;
  - the compensation paid to offshore wind energy producers if the connection deadline is missed or in case of damage or dysfunctions in the connection installations leading to a partial or total limit on production;
  - the amounts adopted for the mechanism for taking into account smart grid industrial deployment projects (smart grid counter);
  - the difference between the trajectory adopted by CRE for voltage ancillary services and any updates during the tariff period;
  - annual forecast difference between estimated revenues and the projected allowed revenue;
- from which is deducted the sum of the amounts adopted for the following revenue items:
  - revenues from interconnection capacity allocation and revenues from capacity mechanisms net of compensation paid by RTE in case of capacity curtailments on interconnections;
  - net revenues related to TSO exchange agreements;
  - reductions, penalties and compensation related to the interruptibility mechanism and voltage ancillary services;
  - reductions, penalties and compensation related to balancing reserves;
  - revenues associated with the gains made from the disposal of real estate or land assets;
  - any balances remaining in suppliers' capacity imbalance settlement account and in the imbalance settlement account of capacity portfolio managers;
  - revenues resulting from any payments from operators of new exempt interconnections;
- to which is added the sum of the amounts adopted for financial incentives for:
  - the price effect on asset management;
  - the incentive regulation for controlling the costs of major grid investment projects;
  - the incentive regulation for controlling the costs of grid projects excluding major projects;
  - the incentive regulation for projects to create new interconnection capacity;
  - the incentive regulation for supply continuity;
  - the incentive regulation for the quality of data publication and external innovation;
- to which is added the reconciliation of the forecast CRCP balance of TURPE 5 HTB.

For the year 2024, the amounts received for incentive regulation relating to asset management, control and prioritisation of investment expenses and R&D are taken into account to calculate the definitive allowed revenue.

For each item, the method for calculating the amount adopted is presented in detail below.

2.1 Expense items taken into account to calculate the definitive allowed revenue

a) Forecast net incentive-backed operating expenses

Forecast net incentive-backed operating expenses are net operating expenses excluding the items fully or partially covered in the CRCP specified in section 2.3.3 of the present deliberation and the stranded costs specified in section 2.1.h) of the present annex. The reference values for forecast net incentive-backed operating expenses are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for forecast net incentive-backed operating expenses	2,083	2,116	2,131	2,165

The amount used in the calculation of the definitive allowed revenue takes into account the difference between forecast and actual inflation.

This amount is equal to the reference value for year *N*:

- divided by forecast inflation between the year 2019 and the year *N*;

	2020	2021	2022	2023	2024
Forecast inflation between year 2019 and year *N*[67]	0.20%	0.80%	1.81%	3.03%	4.58%

- multiplied by actual inflation between year 2019 and year *N*. Actual inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by INSEE for all households in the whole of France (INSEE reference 0001763852), recorded for calendar year *N*, compared to the average value of the same index recorded for calendar year 2019.

b) Forecast "*non-grid*" incentive-backed normative capital expenses

The amount adopted for the calculation of the definitive allowed revenue is equal to the reference values presented below of normative capital expenses related to “information systems”, “light vehicles” and “real estate” assets with the exception of the Lille and Marseille projects.

Forecast values for "*non-grid*" incentive-backed normative capital expenses are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for “*non-grid*" incentive-backed normative capital expenses	189	207	223	235

c) Other normative capital expenses

The amount adopted for the calculation of the definitive allowed revenue is equal to the capital expenses recorded, with the exception of those taken into account in the “*non-grid*" incentive-backed capital expenses. These capital expenses are calculated on the basis of the actual amounts of investments, commissioning, asset retirements and depreciation.

On an indicative basis, the forecast values for these capital expenses (including the capital expenses for the Lille and Marseille projects) are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for other normative capital expenses	1,496	1,542	1,601	1,678

d) Expenses for loss compensation

As from the year 2021, for a given year *N*, the annual incentive relating to the compensation of losses in the public transmission grid corresponds to 20% of the difference between the annual reference amount P_N and the actual expenses borne by RTE, for loss compensation of year *N*. It is capped at +/-€15 million per year.

The annual incentive is first calculated based on provisional data, and the following years based on updated data. The reference amount taken into account for the calculation of the definitive allowed revenue for year *N* is equal to the sum of:

- expenses relating to loss compensation effectively borne by RTE during year *N*;

  On an indicative basis, the forecast values for these purchase costs for loss compensation, excluding incentive regulation, are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for expenses relating to loss compensation	544	518	517	530

- the amount of annual incentive for year *N-1*, calculated based on the provisional data available;
- for year *N-2*, the differences between the annual incentive amount for this year, calculated based on the updated data and that of this same incentive calculated the previous year based on provisional data.

[67] Values rounded off for the purpose of clarity. The values adopted for the calculation of the definitive allowed revenue are the exact values based on the inflation curve mentioned in section 3 of the present deliberation.

The incentive on volume and the purchase price of losses is calculated using the following formula:

$$Incentive_{\ N} = 20\ \% * (V_{reference,\mathrm{N}} * P_{reference,N}\ - V_{observed,\mathrm{N}} * P_{observed,\mathrm{N}})$$

Where:

- $V_{reference,N}$ is the reference volume for year *N*;
- $V_{observed,\mathrm{N}}$ is the volume of losses observed in the public transmission grid for year *N*;
- $P_{reference,\mathrm{N}}$ is the reference unit price for year *N*;
- $P_{observed,\mathrm{N}}$ is the average price observed for loss compensation in the public transmission grid for year *N*.

Reference annual volume $V_{reference,N}$

The annual reference volume for a year *N* is calculated as of 2021 based on the parameters defined in the present deliberation.

The annual reference volume is determined each year by the product between the reference loss rate fixed at 2.20% and the volume of total injections in the public transmission grid (which includes both generation injected into the grid and imports).

Reference unit price $P_{reference,N}$

The annual reference volume for a year *N* is calculated as of 2021 based on the parameters defined in the present deliberation.

The reference unit price of losses is equal to the average price of a basket of products comprising “medium-term”, “short-term” and “capacity guarantee” products. The basket of products adopted is used to cover a load curve of losses on an hourly basis. This load curve corresponds to RTE’s load curve of losses providing the best view of losses at the date of calculation of the reference unit price.

The “medium-term” basket of products comprises annual, quarterly and monthly baseload and peakload products, the breakdown of which is determined to cover as best as possible on average the forecast load curve.

A reference price is adopted for each “medium-term” product (with the exception of the annual baseload product).

For the baseload annual product, the reference price takes into account market prices and the ARENH (regulated access to historical nuclear power) price to reflect the TSO’s possibility of arbitrating based on the change in the difference between market prices and the ARENH price, while considering liquidity constraints.

The “capacity guarantee” basket comprises capacity guarantees excluding capacity included in the ARENH product.

The “short-term” basket comprises day-ahead products.

A reference gross unit price is thus calculated as the weighted average of the reference prices of the different products in the basket. This reference gross unit price does not take into account a certain number of elements such as:

- transaction fees;
- the effect of imperfect market liquidity;
- the existence of differences for the loss balance responsible party;
- any bias inherent to reference price modelling (correlation between several risks in particular).

The reference gross unit price is therefore increased by a coefficient reflecting these effects.

The costs related to physical withdrawals of the grid operator as a balance responsible party are also taken into account through the applicable value of the coefficient c, which is defined in the rules related to programming, the balancing mechanism and the balance responsible party mechanism in effect.

The details on the calculation of the reference unit price are specified in a confidential annex to the present document.

e) Expenses related to the constitution and reconstitution of balancing reserves

The amount adopted for the calculation of the definitive allowed revenue is the sum:

- of the reference operating expenses for the constitution and reconstitution of balancing reserves. These expenses correspond to the trajectory adopted in the present deliberation and specified below. As specified in section 2.3.1.4 of the TURPE 6 HTB deliberation, these reference expenses may be updated by CRE as from the year 2022.
-

€million$_{nominal}$	2021	2022	2023	2024
Reference value for expenses related to the constitution and reconstitution of balancing reserves	218	194	191	192

- 80% of the difference between the expenses for the constitution and reconstitution of balancing reserves effectively observed in year *N* and the reference value, which may have been updated, of year *N*.

f) Expenses related to international and national congestion

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the sum:

- of the reference expenses related to international and national congestion of year *N* adopted in the present deliberation and specified below:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for expenses related to international and national congestion	22	29	37	42

- 80% of the difference between the expenses related to international and national congestion effectively recorded in year *N* and the reference value of year *N*.

g) Expenses related to the interruptibility mechanism

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the expenses related to the interruptibility mechanism effectively borne by RTE.

h) Expenses related to stranded costs

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the sum:

- of the expenses related to stranded costs (“net book value of demolished assets” and “studies and work not followed through") of year *N* adopted in the present deliberation and specified below:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for stranded costs	30	30	30	30

- any other stranded costs, deemed non-recurring or foreseeable, which will effectively be adopted by CRE for the year *N* following an examination of assets removed from inventory before the end of their useful life, based on substantiated proposals by RTE.

i) Compensation paid by RTE to the DSOs for long outages resulting from the public transmission grid

The net incentive-backed operating expenses, presented in section 2.1.a) of the present annex includes a reference amount of €1.8 million/year for compensation paid by RTE to the DSOs for long outages resulting from the public transmission grid.

However, the compensation paid by RTE above €9 million/year is entirely covered by the tariff.

Therefore, the amount adopted for the calculation of the definitive allowed revenue of year *N* is:

- zero if the amount of the compensation effectively paid by RTE to the DSOs for long outages resulting from the public transmission grid is lower than €9 million;

- equal to the difference between, on the one hand, the compensation effectively paid by RTE to the DSOs for long outages resulting from the public transmission grid, and on the other hand, €9 million if the amount of the compensation effectively paid is higher than €9 million.

j) Costs of studies not followed through related to the abandonment of large investment projects when these studies have been approved by CRE

Within the framework of its activities, RTE may be required to conduct studies in view of carrying out its investments. When the investment is completed, the costs of the studies are included in the cost of the investment. However, if these studies lead RTE to not implement its investment project, these study costs become operating expenses for RTE.

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the costs of the studies not followed through related to the abandonment of large investment projects effectively borne by RTE when these studies have been approved by CRE.

k) Rebalancing costs and penalties paid by capacity mechanism actors

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the actual costs of rebalancing and the penalties effectively paid by the capacity mechanism actors.

l) Costs for contracting flexibility procured for the purpose of congestion management within the framework of experimental calls for tenders

In accordance with the roadmap validated by CRE during its examination of the TYNDP, RTE must conduct experimental calls for tenders to contract flexibility for the purpose of congestion management.

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the flexibility contracting costs effectively borne by RTE.

m) Compensation paid to offshore wind energy producers

In accordance with article L. 341-2 4° of the energy code, the tariff for the use of the public electricity transmission grid covers the compensation paid by RTE to producers of electricity using offshore renewables (i) in case of non-compliance with the connection deadline specified by the connection agreement or, failing that, by article L. 342-3, and (ii) in case of damage or dysfunctions in the connection installations leading to a partial or total limit on production in accordance with article L. 342-7-1.

Article L. 341-2 4° however states that "*when the cause of the delay or the limit on production due to damage or a dysfunction in the connection infrastructure of offshore facilities is attributable to the system operator, this operator is liable for a portion of this compensation, in the limit of a percentage and an amount in absolute value calculated for all of the facilities per calendar year, fixed by order of the Minister of Energy after the Energy Regulatory Commission has given its opinion*".

The order of 10 November 2017 taken in that regard specifies that the amount to be paid by RTE covered by TURPE is determined by CRE in the limit of 40% of the compensation paid, and in the limit of a cap of €70 million per calendar year for all production facilities.

In accordance with these provisions, CRE shall determine, on a case-by-case basis, the amount of compensation to be borne by RTE for the year *N*. The amount adopted for the *ex post* calculation of the allowed revenue of year *N* is equal to the amounts effectively fixed by CRE within this framework.

n) Inclusion of smart grid industrial deployment projects

RTE may request, once per year, for inclusion upon the annual update of TURPE, the integration of additional operating costs and/or normative capital expenses associated with IS investments and relating to a project, or a set of projects, falling within the deployment of smart grids. This integration is possible for projects involving operating expenses or normative capital expenses associated with IS investments of over €1 million, subject to a favourable cost/benefit analysis of the project, and for expenses not forecast at the entry into effect of TURPE. Where appropriate, incentive regulation elements associated with these projects may be added.

The operating and capital expenses as well as the associated incentive amounts adopted in that regard in the calculation of the definitive allowed revenue of year *N* are determined by CRE.

o) Difference between the trajectory of voltage ancillary services and any update

The amount adopted for the calculation of the definitive allowed revenue of year *N* corresponds to the difference between the reference trajectory adopted for voltage ancillary services of year *N* and any update of this trajectory in the same year.

The reference trajectory adopted in the present deliberation is specified below:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for voltage ancillary services	107	107	109	111

p) Annual differences between forecast revenues and forecast allowed revenue

Annual differences between forecast revenues and the forecast allowed revenue are those resulting from the balance over the 2021-2024 period between the forecast revenues and the forecast allowed revenue taken into account to prepare TURPE 6.

Year *N*, the annual difference used for the calculation of the definitive allowed revenue is as follows:

€million$_{nominal}$	2021	2022	2023	2024
Annual differences between forecast revenues and allowed revenue	82	17	-22	-82

2.2 Revenue items used for the calculation of the definitive allowed revenue

a) Revenues from interconnection capacity allocation and from capacity mechanisms

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the revenues effectively received by RTE for year *N* for interconnection capacity allocation and capacity mechanisms.

On an indicative basis, the forecast values adopted in the present deliberation are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for interconnection revenues	419	360	343	342

b) Net revenues related to TSO exchange agreements

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the net revenues effectively received by RTE for year *N* under contracts for exchanges between transmission system operators.

On an indicative basis, the forecast values adopted in the present deliberation are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for net revenues related to contracts for exchanges between transmission system operators	-0.2	-0.2	-0.2	-0.2

c) Reductions and penalties related to the interruptibility mechanism and to voltage ancillary services

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the revenues effectively received by RTE for year *N* as part of reductions and penalties related to the interruptibility mechanism and voltage ancillary services.

On an indicative basis, the forecast values adopted in the present deliberation are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for reductions and penalties related to the interruptibility mechanism and voltage ancillary services	-14	-14	-14	-14

d) Reductions, penalties and compensation related to balancing reserves

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the sum:

- of reductions, penalties and compensation related to the reference balancing reserves of year *N* adopted in the present deliberation and specified below:

€million$_{nominal}$	2021	2022	2023	2024
Reference value for reductions, penalties and compensation related to balancing reserves	-11	-11	-11	-11

- 80% of the difference between the reductions, penalties and compensation related to balancing reserves effectively received year *N* and the reference value for the year.

e) Revenues associated with the gains made from the disposal of real estate or land assets

The reference amount taken into account for the calculation of the definitive allowed revenue of year *N* corresponds to 80% of the proceeds from the disposal, net of the net book value of the asset sold.

f) Any balances remaining in suppliers' capacity imbalance settlement account and the imbalance settlement account of capacity portfolio managers

The amount adopted for the calculation of the definitive allowed revenue of year *N* corresponds to the balances effectively remaining in suppliers' capacity imbalance settlement account and the imbalance settlement account of capacity portfolio managers.

g) Revenues resulting from any payments from operators of new exempt interconnections

The amount adopted for the calculation of the definitive allowed revenue of year *N* corresponds to the revenues recorded coming from payments by operators of new exempt interconnections for year *N*.

2.3 Financial incentives under the incentive regulation

a) Price effect on asset management

The present deliberation introduces a principle of partial coverage of the price effect of the unit costs of the sub-items "pylon painting" and "rehabilitation of power transformers" of the asset management policy (see section 3.1.2.4.2 of the present deliberation).

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal, for each of these sub-items, to the product of 50% of the difference between the unit cost observed and the reference unit cost defined in the confidential annex 6, and the volume of operations effectively performed by RTE during year *N*.

b) Incentive regulation for controlling the costs of major grid investment projects

The present deliberation includes an incentive regulation for controlling large investment projects (see section 2.3.2.2).

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the incentives for controlling the costs of large investment projects of an amount higher than €30 million, put in service during year *N*. Where applicable, the amount of this incentive will be recalculated in year *N+2* or *N+3* if additional investment expenses are observed following the commissioning of the project.

c) Incentive regulation for controlling the costs of grid projects excluding major projects

The present deliberation introduces an incentive regulation for controlling the costs of grid projects excluding major projects (see section 2.3.2.3).

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the incentives for controlling the costs of such projects put in service in year *N*. Where applicable, the amount of this incentive will be recalculated in year *N+2* or *N+3* if additional investment expenses are observed following the commissioning of the project.

d) Incentive regulation for new interconnection capacity projects

The present deliberation includes a financial incentive mechanism for the development of interconnection projects (see section 2.3.2.4). The amount of these incentives is calculated within the framework of a specific tariff deliberation for each project.

The amount adopted for the calculation of the definitive allowed revenue of year *N* is equal to the financial incentives for new interconnection capacity projects defined in the specific tariff deliberations for each project.

e) Incentive regulation for continuity of supply

A follow-up of the continuity of supply is implemented for RTE. This follow-up comprises indicators transmitted regularly by RTE to CRE. All of the follow-up indicators on continuity of supply set up by for RTE must be published on its website.

The list of indicators relating to continuity of supply defined for TURPE 6 HTB is contained in annex 2 of the present deliberation.

RTE's indicators relating to annual average durations and frequencies of outages of users connected to the HTB range are subject to financial incentives. The objectives and amounts of penalties for indicators subject to financial incentives shall apply as from 1 January 2021.

The mechanism for following RTE's continuity of supply may be submitted to any audit deemed useful by CRE.

The amount adopted for the calculation of the definitive allowed revenue of year *N*, under incentive regulation for continuity of supply, is equal to the sum of the two financial incentives defined in section 2.3 of annex 3 for the year in question, within the overall limit of -€45 million.

f) Incentive regulation for the provision of data (quality and deadlines)

A follow-up of RTE's quality of data and compliance with deadlines for their provision is implemented by the present deliberation. This follow-up comprises indicators transmitted regularly by RTE to CRE. All of the follow-up indicators on the quality of data or the deadlines for their provision, must be published on RTE's website.

The list of follow-up indicators relating to provision of data (quality and deadlines) is contained in section 2.5.3 of the present deliberation.

Certain indicators may be subject, during TURPE 6 HTB, to a financial incentive system based on the change in performance observed. In addition, new indicators may be introduced by CRE (for follow-up or financial incentive), as specified in section 2.5.3.

The mechanism for following the provision of data may be subject to any audit that CRE deems useful.

The amount adopted for the calculation of the definitive allowed revenue of year *N*, under incentive regulation for the provision of data, is equal to the amount of financial incentive(s) that may be decided by CRE within this framework, for year *N*.

g) Incentive regulation for supporting external innovation

The present deliberation introduces a financial incentive mechanism for compliance by RTE with the implementation deadlines of actions identified as priorities for promoting innovation in market participants.

The list of priority actions concerned by this incentive regulation as well as the implementation deadlines and the associated amounts and penalties in the case of non-compliance with the deadlines, are contained in section 2.5.4 of the present deliberation. CRE may introduce, during TURPE 6 HTB, new priority projects which will be subject to this incentive regulation, as presented in section 2.5.4 The amounts of the penalties calculated on an annual basis shall apply as from the year 2021.

The amount adopted for the calculation of the definitive allowed revenue of year *N*, under incentive regulation for supporting external innovation, is equal to the amount of the penalty(ies) resulting from the application of this regulation for year *N*.

2.4 Reconciliation of the forecast CRCP balance of TURPE 5 HTB

The reference amount taken into account for reconciliation of the forecast CRCP balance for TURPE 5 HTB is as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reconciliation of the forecast CRCP balance of TURPE 5 HTB	1.5	1.5	1.5	1.5

2.5 Financial incentives taken into account at the end of the tariff period

a) Incentive regulation for asset management

TURPE 6 HTB introduces a specific regulation mechanism for asset management (see section 2.3.1.2 of the present deliberation).

Within the framework of this mechanism, every year RTE shall transmit to CRE a follow-up report on all asset management expenses as well as a follow-up report on the associated investments. At the end of the TURPE 6 period, CRE will review the volumes of work effectively conducted by RTE in comparison with the reference trajectory of volumes listed in the confidential annex 6.

If RTE has not executed all of the operations planned over this period within the framework of its asset management policy, the forecast expenses associated with the operations not carried out will be returned to grid users, which will be equal to the volumes not performed multiplied by the unit costs used to construct the tariff trajectory.

The amount determined at the end of this mechanism will be taken into account in the CRCP balance at the end of the tariff period.

b) Incentive regulation for controlling and prioritising investment expenses

TURPE 6 HTB introduces an incentive mechanism for controlling and prioritising investment expenses (see sections 2.3.2.1 and 3.1.3.2 of the present deliberation).

Within the framework of this mechanism, CRE sets a four-year cap accompanied by a financial incentive on certain investment expenses, the scope of which is defined in section 2.3.2.1 of the present deliberation. This cap is set at €3,967 million$_{nominal}$.

If the sum of investment expenses over the tariff period exceeds this envelope, an amount corresponding to 20% of the difference between the four-year cap and the investment expenses actually recorded will be taken into account in the calculation of the CRCP balance at the end of the tariff period.

c) Incentive regulation of research and development (R&D) expenses

The present deliberation includes an incentive regulation mechanism for R&D expenses (see section 2.5.1).

If the total amount of R&D expenses (including expenses related to smart grids projects and minus subsidies) incurred over the 2021-2024 period is lower than the cumulated reference amounts used to prepare the TURPE 6 HTB tariff, the difference will be taken into account in the CRCP balance at the end of the tariff period.

The reference amounts for R&D expenses (including expenses related to smart grids projects and minus subsidies) taken into account to define the TURPE 6 HTB tariff are as follows:

€million$_{nominal}$	2021	2022	2023	2024
Reference amount for R&D expenses (minus subsidies) subject to incentive regulation	38	39	39	40

The possibility exists for this reference trajectory to be revised mid-period.

Transparency and verification of the efficiency of spending associated with R&D are ensured, among other things, by the annual transmission to CRE of technical and financial information for all the projects completed and in progress.

This follow-up may be submitted to any audit deemed useful by CRE.

ANNEXE 2 - INCENTIVE REGULATION FOR RTE'S QUALITY OF SERVICE AND SUPPLY

Table 1 : Indicators of RTE's quality of service and supply for TURPE 6 HTB

	Indicators followed or subject to incentives	Other
Connections	• Follow-up of compliance with the deadlines in the technical and financial proposal • Follow-up of compliance with the deadlines in the connection agreement • Follow-up of the differences between actual costs and costs in the connection agreement • Follow-up of the differences between actual costs and costs in the technical and financial proposal +/-15% • Follow-up of average connection timeframes by segment: offshore wind / onshore renewables / distributors and consumers	
Metering	• Follow-up of compliance with meter repair intervention deadlines	
Claims	• Follow-up of the rate of response within 10 days • Follow-up of the rate of claims processing within 30 days • Follow-up of the average overall duration for claims processing	
Waveform quality	• Follow-up of the average duration of maximum voltage exceedance, by voltage level • Follow-up of the average frequency of voltage in the exceptional high end of the voltage range, by voltage level	• Within the framework of working groups for voltage ancillary services, initiate work on the most relevant indicators for measuring waveform quality
Continuity of supply	• Financial incentive on the equivalent outage time • Financial incentive on the average outage frequency • Follow-up of compliance with contract commitments relating to electricity quality in the transmission grid access contract • Follow-up of energy not evacuated by producers due to RTE's activities in the public transmission grid • Follow-up of compliance with work dates and durations planned by RTE in the public transmission grid for industrial clients	• Implementation of an online platform indicating RTE's work plan • Satisfaction questionnaire after completion of work sent by RTE to its clients • Compensation paid to DSOs in the case of long outages (longer than five hours) in the public distribution grids resulting from the public transmission grid
Access to the market/data	• Follow-up of the availability rate of RTE's service portal platform • Follow-up of the accuracy rate of the trend data of the balancing mechanism • Follow-up indicator for the quality of the level of effective capacity and the estimated and definitive capacity obligations forwarded by RTE to the concerned participants • Follow-up indicator for compliance with the deadline for the publication of the declaration of the evolution of the certified capacity level updated in the certified capacity register	

	• Follow-up indicator for compliance with certification deadlines (deadline for transmitting the certification contract to the capacity operator) • Follow-up indicator for compliance with the deadline for transmitting the control of activated bids on the balancing mechanism	

ANNEXE 3 - INCENTIVE REGULATION FOR CONTINUITY OF SUPPLY

1. EXCEPTIONAL EVENTS

Within the framework of the incentive regulation for continuity of supply, the following are considered to be exceptional events:

- destruction due to acts of war, riots, looting, sabotage, attacks, criminal acts;
- damage caused by accidents and events that cannot be controlled, caused by third parties, such as fires, explosions and plane crashes;
- natural disasters defined by the French amended law No. 82-600 dated 13 July 1982;
- sudden, unplanned and simultaneous unavailability of several generation facilities connected to the public transmission grid, once unavailable power is greater than the provisions of the security rules mentioned in article 28 of the standard public electricity transmission grid concession specifications (appended to French Order No. 2006-1731 dated 23 December 2006);
- decommissioning of infrastructure decided by public authorities on the grounds of public or police safety once this decision is not due to the actions or inaction of the public electricity system operator;
- atmospheric phenomena of an exceptional nature with regard to their impact on the grids, characterised by an annual probability of incidence of less than 5% for the given geographical area once at least 100,000 end users supplied by the public transmission and/or distribution grids go without electricity in one day and for the same reason. In island areas not interconnected with mainland grids having fewer than 100,000 clients, the abovementioned threshold is lowered to half the number of clients connected in the area in question.

2. FOLLOW-UP OF CONTINUITY OF SUPPLY

This part of the annex outlines the indicators for monitoring RTE's continuity of supply as well as the corresponding financial incentives defined for TURPE 6 HTB.

2.1 Average outage duration

Table 1 : Parameters of the incentive regulation mechanism for average outage duration

Calculation	The average outage duration of year *N* for the HTB voltage range ($\mathrm{DMC_N}$) is defined as the ratio between (i) the total energy not distributed of year *N* and (ii) the average supplied power of year *N*. $$DMC_N = \frac{Total\ END\ of\ year\ N \times 60}{PMDA\ (excluding\ losses) of\ year\ N}$$ END: energy not distributed, expressed in MWh. Energy not distributed is determined excluding incidents occurring after exceptional events (see definition above). The calculation of energy not distributed includes load shedding for reasons related to the public transmission grid. PMDA: average supplied power, expressed in MW. PMDA is obtained by dividing the value of the energy supplied (excluding losses) in the year by 8,760 hours (or 8,784 hours if year *N* is a leap year).
Scope	• DMC_N is determined excluding incidents occurring after exceptional events
Monitoring	• Frequency of calculation: monthly • Frequency of reporting to CRE: quarterly • Frequency of publication: quarterly • Frequency of incentive calculation: yearly
Objective	• Reference objective ($DMC_N ref$) : 2.8 minutes / year
Incentives	• The overall amount of the incentive I_N for year *N* is indicated in section 2.3

Implementation date	• 1 January 2021

2.2 Average outage frequency

Table 2 : Parameters of the incentive regulation mechanism for average outage frequency

Calculation	The average outage frequency of year *N* for the HTB voltage range ($\mathrm{FMC_N}$) is defined as the ratio between (i) the number of long and short outages of year *N* and (ii) the number of installations as at 31 December of year *N*. $$FMC_N = \frac{Number\ of\ long\ and\ short\ outages\ of\ year\ N}{Number\ of\ installations\ as\ at\ 31\ December\ of\ year\ N}$$ Long outage: cut in an installation's power supply for more than 3 minutes. Short outage: cut in an installation's power supply for between 1 second and 3 minutes.
Scope	• FMC_N is determined excluding incidents occurring after exceptional events
Monitoring	• Frequency of calculation: monthly • Frequency of reporting to CRE: quarterly • Frequency of publication: quarterly • Frequency of incentive calculation: yearly
Objective	• Reference objective ($FMC_N ref$): 0.46 outages / year
Incentive	• The overall amount of the incentive I_N of year *N* is indicated in section 2.3
Implementation date	• 1 January 2021

2.3 Calculation of the overall amount of the incentive for a year *N*

The present deliberation introduces for TURPE 6 HTB an asymmetrical incentive for the two indicators on average outage duration and frequency, and the overall amount of the incentive I_N for a year *N* is obtained by:

$$I_N = \mathrm{Min}\big(17 \times (DMC_{réf} - DMC_N) + 109 \times (FMC_{réf} - FMC_N)\,;0\big)$$

The incentive cap is fixed at €45 million/year.

Payment is performed through the CRCP.

3. OTHER FOLLOW-UP INDICATORS FOR RTE'S CONTINUITY OF SUPPLY

Before the end of each calendar quarter, RTE must provide CRE with the following information relating to the previous quarter:

- energy not distributed (for all reasons);
- energy not distributed excluding exceptional events;
- energy not distributed during load shedding (for all reasons);
- energy not distributed during load shedding excluding exceptional events;
- the number of long and short power cuts (for all reasons);
- the number of long and short power cut excluding exceptional events;
- for each exceptional event (see definition in section 1): any factor justifying the exceptional nature of the event, the energy not distributed, the number of long and short outages during the event and any factor for evaluating the rapidity and relevance of the measures taken by RTE to restore normal operating conditions.

Before the end of first quarter of each year, RTE must provide CRE with the following information relating to the previous year:

- the annual average duration of power outages (for all reasons);
- the annual average duration of power outages excluding exceptional events;
- the annual average duration of power outages following load shedding (for all reasons);
- the annual average duration of power outages following load shedding excluding exceptional events;
- the annual average frequency of power outages (for all reasons);
- the annual average frequency of power outages excluding exceptional events.

ANNEX 4 – EVOLUTION IN BILLS FOR THE USE OF THE PUBLIC ELECTRICITY TRANSMISSION GRID

At the request of CRE, RTE simulated bills resulting from the application of the TURPE 6 HTB tariffs as at 1 August 2021 to the load curves of HTB clients from 2015 to 2019. The simulated changes in the bills presented in this annex take into account the structure development for the withdrawal component and the general +1.09% change in the tariff level. They are based on the assumption that users re-optimise the tariff versions and subscribed power between TURPE 5 HTB and TURPE 6 HTB. These simulations take into account the forecast drop in withdrawals between 2019 and the 2021-2024 period.

The difference between the general change in the 2021 tariff level and the average bill changes simulated using the tariffs as at 1 August 2020 and at 1 August 2021 applied to the 2015-2019 load curves is due to compensation of the "subscribed power / energy withdrawn" ratio, the tariff structure development, compensation of the increase in the management component (excluded from the scope of simulations), the trajectory of the reduction for electricity-intensive sites and a rounding-off effect.

Tables 1 and 2 present the average bill changes simulated for HTB 2 and HTB 1 users grouped together by use durations (annual energy withdrawn / annual maximum power).

Table 3 presents the average bill changes simulated for HTB 3, HTB 2 and HTB 1 users grouped together by business sector.

Table 1 : Bill changes between TURPE 5 HTB as at 1 August 2020 and TURPE 6 HTB as at 1 August 2021 for a representative user connected to the HTB 2 voltage range

HTB 2 representative users	Duration of use (DU) in hours	Number of HTB 2 users	Bill change
User representative of DU between 0 and 3,000 hours	866	254	1.32%
User representative of DU between 3,000 and 5,000 hours	4,187	221	0.12%
User representative of DU between 5,000 and 8,760 hours	6,012	65	1.96%

Table 2 : Bill changes between TURPE 5 HTB as at 1 August 2020 and TURPE 6 HTB as at 1 August 2021 for a representative user connected to the HTB 1 voltage range

HTB 1 representative users	Duration of use (DU) in hours	Number of HTB 1 users	Bill change
User representative of DU between 0 and 3,000 hours	1,275	1,311	0.00%
User representative of DU between 3,000 and 5,000 hours	4,058	1,694	0.61%
User representative of DU between 5,000 and 8,760 hours	5,889	261	0.40%

Table 3 : Bill changes by sector between TURPE 5 HTB as at 1 August 2020 and TURPE 6 HTB as at 1 August 2021 (including reduction for electricity-intensive sites)

Sector	Bill change			
	HTB 1	HTB 2	HTB 3	TOTAL
Agriculture and agri-food	1.21%	2.69%		1.51%
Automobile	0.82%	1.77%		0.97%
Other industries	0.74%	5.87%		0.76%
Chemicals	0.66%	2.50%	3.13%	1.30%
Electricity distribution	0.38%	0.64%	3.13%	0.56%
Energy and fuel	0.44%	0.13%		0.40%
Metallurgy	1.19%	2.25%	3.12%	1.29%
Minerals and materials	0.53%	2.30%	3.12%	1.21%
Paper	1.31%	1.29%		1.31%
Electricity generation	1.26%	2.81%	3.12%	1.43%
Steel	3.70%	5.30%	3.12%	3.65%
Tertiary	5.71%	3.63%	3.12%	4.32%
Non-rail transport and Telecom	1.52%	1.78%	3.12%	1.66%
Rail transport	2.06%	0.89%	3.12%	1.73%
TOTAL	0.50%	0.42%	3.12%	0.50%

ANNEX 5 – INCENTIVE REGULATION FOR THE PURCHASE PRICE OF ENERGY AND CAPACITY FOR LOSS COMPENSATION FOR TURPE 6 HTB (CONFIDENTIAL ANNEX)

This annex is confidential.

ANNEX 6 – ASSET MANAGEMENT MECHANISM (CONFIDENTIAL ANNEX)

This annex is confidential.

ANNEX 7 – METHODOLOGY ADOPTED TO DETERMINE THE WITHDRAWAL COMPONENT OF TURPE 6

Work undertaken to prepare TURPE 5 regarding the withdrawal component led to the improvement in cost allocation, by better taking into account the differentiation in grid unit costs, based on timescale. The changes brought to cost allocation were then based on new consumption data, which were more refined because they stemmed from real users (all HTB users, a significant sample of HTA and BT users). The grid data however were built from, on the one hand, a simplified model of grid infrastructure costs, considering that these increase linearly with the withdrawal peak at national level, and on the other hand, the consideration of load concomitance at national level.

The work done for TURPE 6, presented hereafter, aims to improve this model using more robust grid data enabling greater precision of the methodology used. In particular, system operators submitted much more precise information to CRE regarding the description of their networks. Therefore, CRE was able to base its work on the quantity of infrastructure effectively present in each grid pocket[68] and the load curves of HTB-HTA transformer substations at the top of each of these pockets (and not a single national load curve). This improvement enables better inclusion of, on the one hand, the economies of scale of the grid (doubling the capacity of an infrastructure does not imply doubling the costs), and on the other hand, local effects (all grid infrastructure do not experience the same peak at the same time).

In addition, the sample of HTA and BT users used is improved compared to that used during TURPE 5 work (43,000 delivery points in the simulations of low-voltage withdrawals for TURPE 6, compared to 3,000 in TURPE 5) and is therefore more representative of users' actual form of consumption.

The methodology adopted for TURPE 6, presented hereafter, builds on the TURPE 5 methodology, while refining certain steps in the calculation (inclusion of an access cost, marginal cost rather than average incremental cost, form of the cost function, allocation of compensation costs for power losses and reserves based on flow matrices, etc.). Moreover, it endeavours to comply with the general principles (efficiency, readability, feasibility, acceptability) reiterated previously, supported generally by participants. The tariffs resulting from this methodology are presented in the dedicated annex.

1. GENERAL PRINCIPLE OF COST ALLOCATION

The tariffs are defined based on the allocation of costs to each user, so that the tariff paid by each user best reflects the grid cost they generate, while taking into account the goal to have clear tariffs with changes being applied gradually. This principle sends a relevant tariff signal to users aimed at optimising investment needs and grid operating expenses in the medium term.

The method implemented by CRE in TURPE 6, based on more refined data transmitted by the grid operators concerning their costs, grids and the users' consumption, is based, for the HTB 1 and 2, HTA and BT voltage levels, on the following major steps:

- Step 1– econometric study of infrastructure costs: this first step consists, using the analysis of the data of each grid pocket, in:
    - reconstituting the annualised cost of each pocket;
    - determining the variables most likely to explain the variations in costs between pockets;
    - deducing a cost function, to obtain marginal costs depending on the different cost drivers;
- Steps 2 and 2b – for the two main cost drivers selected (number of users and non-coincident peak load in each pocket), the following step consists in transforming the marginal costs into tariff coefficients, using a large sample of representative users whose hour-by-hour grid use is known;
- Step 3 - adjustment and allocation of ancillary costs: this step consists firstly in adjusting the tariff coefficients homothetically to equalise the infrastructure revenues and expenses to be covered for each voltage range, then taking into account the ancillary costs (power losses, reserves, HTB 3) not included in the cost function established in step 1, and passing them on to consumers by integrating them in the tariff coefficients obtained in steps 2 and 2b.

Cost allocation takes into account the fact that each user uses not only the voltage level to which it is connected, but also, by way of cascading, all of the voltage levels before their own.

[68] Group of network infrastructure associated for their proximity, in terms of impedance, to an upstream transformer.

For the HTB 3 network, steps 1 and 2/2b are simplified. The HTB 3 network contains particularities which leads to reflecting the costs generated by withdrawal in the form of a tariff for energy, without a time differentiation or a subscribed power coefficient. The infrastructure costs of the HTB 3 network represents €0.26 per kWh supplied in this voltage level.

The main steps of this method are shown in the diagram below:

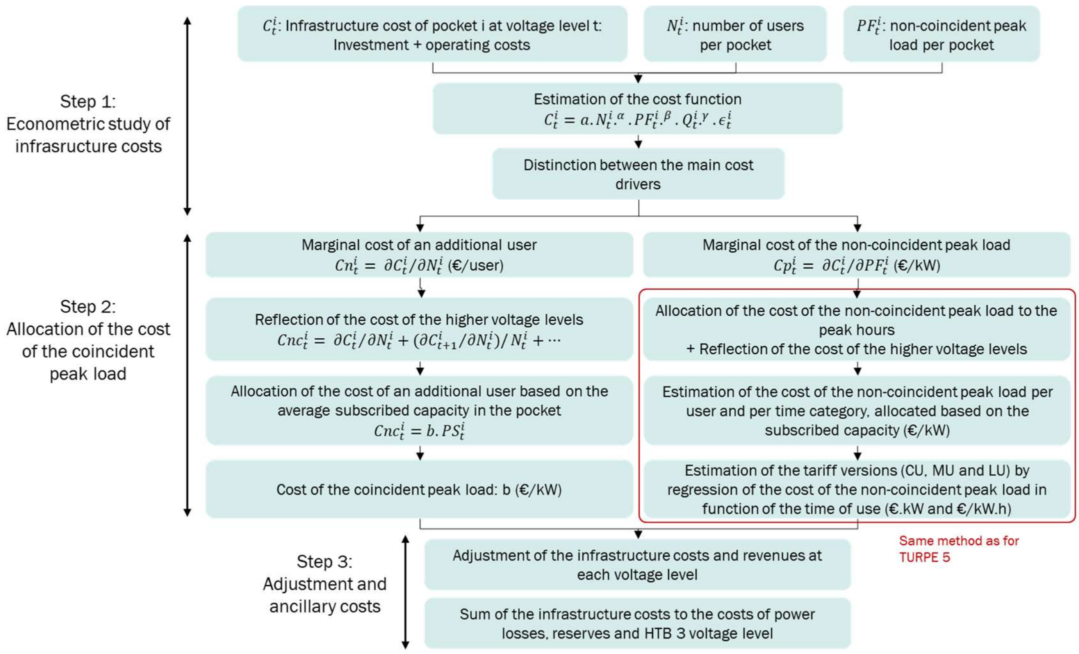

Figure 1 : Steps in the TURPE 6 method

2. STEP 1: ECONOMETRIC STUDY OF INFRASTRUCTURE COSTS

The calculation method used for the TURPE 5 structure has a certain number of particularities which were introduced particularly in response to the lack of details available at the time on infrastructure costs at local level:

- the scope is national;
- the infrastructure costs are assumed to be entirely the result of grid capacity in the voltage level in question;
- based on the implicit cost function of TURPE 5, costs are assumed to be strictly proportional to grid capacity;
- the number of users is assumed to not influence costs;
- the tariff does not aim to reflect the marginal cost, but the average incremental hourly cost.

The work done in preparation of TURPE 6 enable infrastructure costs to be estimated at local level (at grid pocket level, by voltage level), leading to the calculation of a peak marginal cost based on the local development of the grid. This more refined data should serve to more precisely allocate, in the different tariff versions, the costs corresponding to the different uses of the grid.

2.1 Use of more refined data: the grid pockets

A grid pocket includes all of the grid infrastructure of a voltage range connected downstream of a transformer substation. In the case of connection to several substations upstream, the infrastructure is associated with the closest based on electrical distance. Each pocket represents a set of locally coherent grid infrastructure. The number of pockets for each voltage level directly depends on the number of transformer substations between voltage levels. In brief, the grid can be represented as follows:

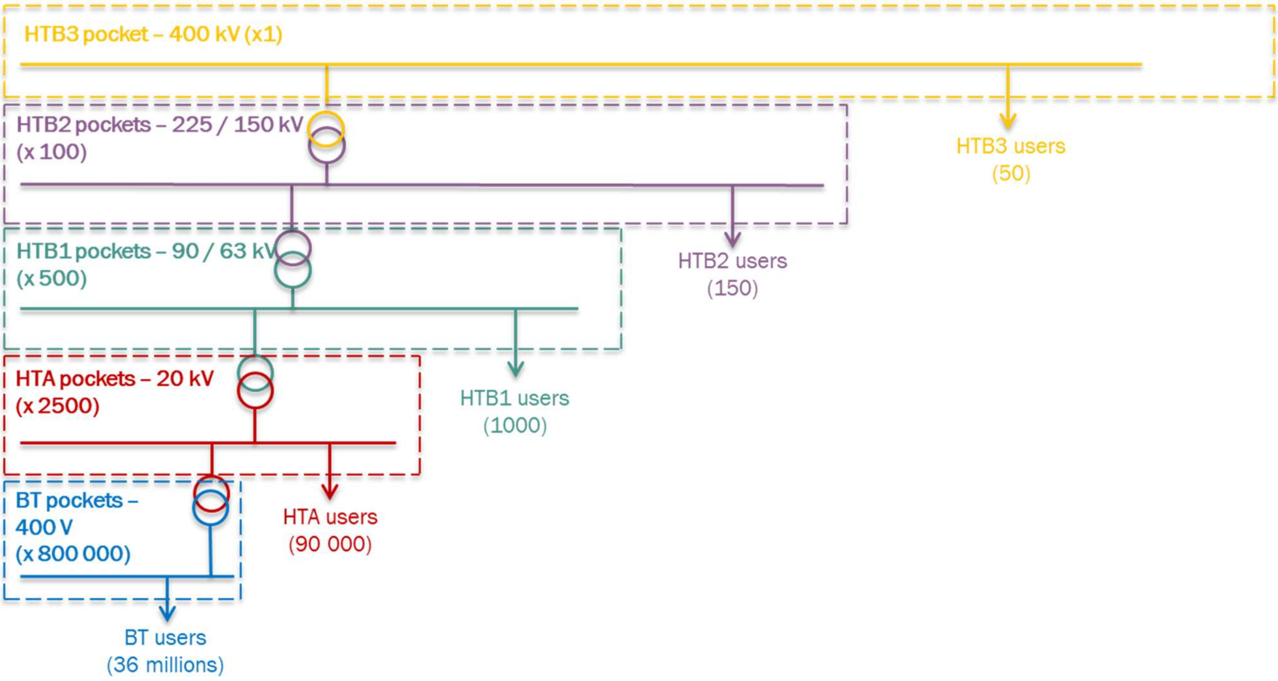

Figure 2 : Breakdown of the grid into pockets (order of magnitude)

For each pocket, the system operators provided numerous data: infrastructure quantities, number and characteristics of users connected, topology and density indicators, load curves, etc.

These data are used to reconstitute the annualised cost of each pocket and explain econometrically these costs by the different variables stemming from the data provided for each pocket (for example number of users, sum of subscribed capacity, maximum power transmitted in the grid, volume of energy supplied during the peak, density, etc.).

The normative cost of a grid pocket is calculated as the sum of the annualised value of the long-term investment costs, and operating costs distributed in proportion to the investment values.

The cost of a grid pocket is directly related to the technical characteristics of infrastructure: the voltage level, the length of connections and capacity of power lines and substations.

2.2 Variables in infrastructure costs

The cost of a grid pocket is partly explained by the characteristics of the users connected to it. It is also sensitive to other factors that do not depend on users' characteristics:

- geographical variables such as the degree of urbanisation, the terrain profile, climate;
- and historical variables such as the dynamics in the region and the planning choices of the system operator.

Table 1 : Data considered by pocket in the econometric analysis

Level	Number of pockets	Total cost (€ million)	Maximum asynchro-nous power (MW)	Number of users or pockets at the lower voltage level	Average cost of Pmax (€/kW)	Average cost per user (€)	Avg. Max. asynchro-nous power per pocket (MW)	Number of average users per pocket	Average power per user (kW)
HTB 2	107	1,420	122,345	879	11.6	1,699,263	1,143	8.2	27,283
HTB 1	446	1,794	94,325	3,146	19.0	808,683	211	7.1	20,846
HTA	2,143	5,265	88,652	92,000	59.4	5,992	41	43.0	360
BT	787,500	6,081	70,900	36,400,000	85.7	167	0.1	46.2	9

The econometric analysis conducted by CRE shows that the cost of a grid pocket depends mainly on the non-coincident peak load[69] and the number of users of each pocket.

Control variables have also been introduced: for all high-voltage levels, the serving surface area; for medium-voltage, power output and density have also been taken into account.

Other variables may be considered, but have not been adopted by CRE for the following reasons:

- external variables (type of housing, etc.) improve the explanatory factor of the model, but do not necessarily provide any information useful for tariffing. Their use may in some cases prove to be counter-productive, if they are correlated with peak power, because they undermine the coefficients of variables to be tariffed, without being tariffed themselves;
- the characteristics of aggregated consumption of a pocket's users, such as the sum of subscribed capacity and the sum of energy withdrawn, are too correlated with each other and with coincident peak load to provide significant information within the framework of the cost function.

Moreover, the HTB 1 and HTB 2 voltage levels were handled as a single voltage range because of the function they perform as sub-transmission network.

2.3 Cost function

The sensitivity of infrastructure costs to the users' characteristics is quantifiable with a Cobb-Douglas cost function. The parameters of this function stem directly from the econometric analysis of costs by pocket.

$$C_{pi} = A.N_i^{\alpha}.PF_{pi}^{\beta}.Q_i^{\gamma}$$

With:

- C_{pi} the cost of the infrastructure of pocket i;
- $N_i$the number of users of pocket i;
- PF_i the non-coincident peak load of pocket i;
- Q_i the control variable of pocket i;
- A a size factor characteristic of the variables adopted;
- α the elasticity of cost to the number of users;
- β the elasticity of cost to non-coincident peak load;
- γ the elasticity of cost to the control variable.

[69] The definition of diversified load aims to reproduce in brief the system operators' sizing decisions. In HTB and HTA, where the network is generally redundant, CRE adopted the power of the 2,500th hour with the highest consumption of each pocket. The transmission grid contains redundancies enabling it to bear the loss of one or more infrastructure, with only partial load shedding being implemented in this case. It is therefore not maximum power that generates investments, but the power during the 2,500 hours with the highest demand, during which consumption risks being shed partially if an infrastructure is lost. The value determined for HTB was adopted for HTA.
For the low-voltage network (BT), since the network is generally not redundant, the BT pockets are designed to guarantee supply in full grid situations, given the consumption uncertainty. The sizing peak is characterised by a shorter duration. CRE adopted a duration of 500 hours for this voltage range.

Table 2 : Elasticity of infrastructure costs to the number of users and non-coincident peak load

	Elasticity of cost to the number of users	Elasticity of the cost to non-coincident peak load
HTB	0.20	0.32
HTA	0.12	0.37
BT	0.13	0.39

The results highlight economies of scale which are characteristic of grid industries, the coefficients appearing in the table above being substantially lower than one. The more developed the network, the less costly the additional developments.

In comparison with the method used for TURPE 5, the cost function adopted for TURPE 6, refines the sensitivity of infrastructure costs to the use of the infrastructure in taking into account the level of development of each grid pocket.

3. STEPS 2 AND 2B: ALLOCATION OF COSTS TO EACH USER

3.1 Calculation of marginal costs to non-coincident peak load and to the number of users

CRE reiterated, in its TURPE 5 deliberation, that the most effective economic signal, based on economic theory, is based on the principle of marginal cost, which involves making users withdrawing at critical times for the grid pay the grid development costs; for the electricity grid, these critical times are predominantly in winter. CRE did not adopt such pricing for TURPE 5, on the one hand because certain data was missing at the time, and on the other hand, to ensure the best continuity with TURPE 4. CRE adopted an average incremental cost methodology for TURPE 5.

CRE stated in its public consultation of October 2020, that it intended, for TURPE 6, to draw closer to a pricing principle based on marginal cost, provided that such a development was feasible.

Participants were generally in favour of marginal-cost pricing in order to send a more effective economic signal to grid users. Some participants expressed reservations about the consequences of such a methodology, which would not be desirable if it caused high bill increases for fragile or temperature-sensitive households.

The pursuit of work conducted by CRE confirmed that such pricing based on marginal cost calculations is relevant for TURPE 6 for the following reasons:

- the fast change in grid use poses considerable challenges for investment in new infrastructure, which could be more or less controlled depending on the way in which the new devices will be used. Against the strong growth in investments, marginal-cost pricing remains one of the most robust econometric methods in this area;
- the more refined grid data collected from system operators make it possible to envisage such pricing;
- bill changes for grid users remain very limited even for the most temperature-sensitive users. The new method provides each user with the incentive to adopt better behaviour with regard to the network without however penalising users that cannot adapt their behaviour.

The following step in the method, consists in deducing from the cost function the marginal costs compared to the number of users and non-coincident peak load. The marginal cost corresponds to the cost of using an additional unit:

- the marginal cost of the number of users is the cost generated by the demand of a new user, at a given non-coincident peak load and with fixed control variables;
- the marginal cost of the non-coincident peak load is the cost generated by a demand for a slightly higher load, with a fixed number of users and fixed control variables.

Therefore, the cost function can isolate the two main effects which are complementary with each other.

3.2 Step 2: Allocation of the marginal cost to the number of users

The marginal cost of the number of users can be considered as a marginal access cost: it corresponds to the cost generated by the addition of a new user in a pocket, for a given non-coincident peak load at the level of the transformer substation. Basically, this would correspond to a new user who would not consume during peak periods. However, at the more local level, it would be necessary to connect this user to be able to serve its subscribed capacity and possibly reinforce the network close to the user, which would generate infrastructure costs.

A part of these costs is paid by grid users at the time of connection through the charging of the connection. Once these revenues are deducted from operators' expenses, a significant portion of expenses remains related to the access service, which must be reflected in the tariffs for the use of the grids.

For each voltage level and each pocket in this voltage level, a marginal cost of the number of users is obtained, in €/user. This cost takes into account the fact that each user uses not only the voltage range to which they are connected, but also, by way of cascading, all of the voltage levels upstream of their own.

However, it would be ineffective to bill this cost at a flat rate; the large differences between voltage ranges would give grid users the incentive to split their delivery points in order to be connected to lower levels which would not be economically efficient. Since this cost is not related to the use of the network by the user once connected, CRE chose, at the level of each pocket, to allocate the overall bill for the marginal access costs in proportion to the subscribed capacity.

3.3 Step 2b: Allocation of the marginal cost to non-coincident peak load

Marginal cost of non-coincident peak load corresponds to the cost generated by the increase in electricity withdrawal during peak periods, for a given number of users. This increase will cause a need for grid investment in the long term, which must therefore be reflected in the grid tariffs.

More specifically, the non-coincident peak load of a pocket refers to the power withdrawn from the transformer substation during the 2,500th hour with the highest load demand of the year. For each voltage level and each pocket of this voltage level, a marginal cost to non-coincident peak load is obtained, in €/kW. As for the coincident peak, this cost is a cascaded cost, i.e. taking into account the use of the upstream levels.

This marginal cost to non-coincident peak load is then distributed across the peak times of the different time categories.

For each user, this cost is then billed similarly to the TURPE 5 method based on the user's presence during the highest periods of consumption of the year. This step is that of versioning described hereafter. It takes place in two phases:

- Representation of the cost generated by a user based on their duration of use

Similar to TURPE 5, for a given voltage level and time category, the cost generated by users of this voltage level depending on their duration of use during the time category considered can be represented in the form of a scatter plot. This plot is used to determine the connection between the different grid use behaviours and the costs they generate, based particularly on the energy withdrawn and the subscribed capacity.

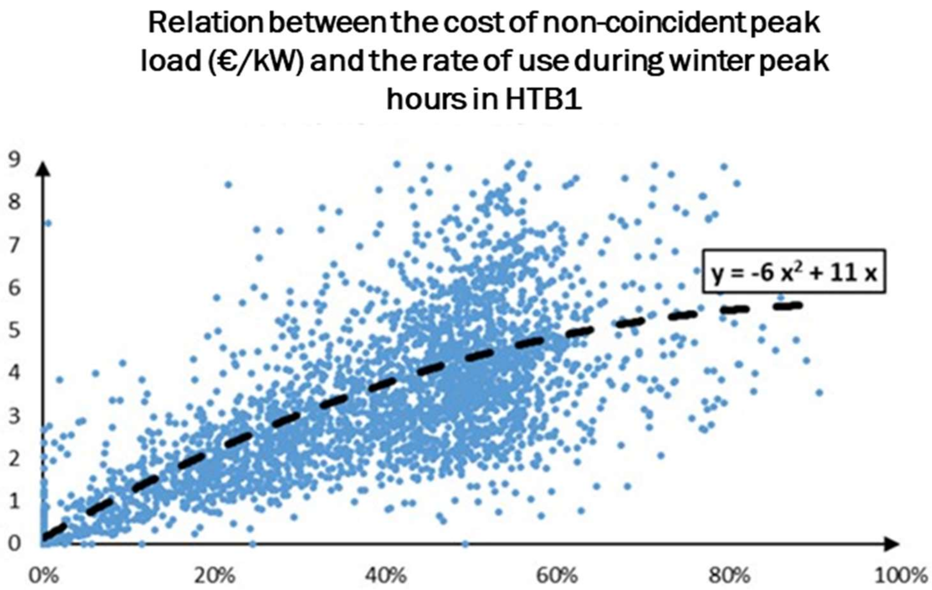

Figure 3 : Infrastructure costs (€/kW maximum power) by user for the peak time category in winter in HTB 1 based on the duration of use at maximum power

To construct these scatter plots, CRE used all of the load curves of users of the HTB voltage range over 20 years (data observed between 2010 and 2019, as well as 10 different weather simulations for the year 2025). The method thus enables the integration of a forward-looking vision of the transmission grid, which responds to the observations of certain participants concerning the TURPE 5 method.

The load curves of transformer substations as well as the aggregated consumption data of users connected to the HTA level, specifying for each of them the distribution between the hour/season categories of their consumption at the time of non-coincident peak of their pocket, were used to proceed similarly for this voltage level.

With regard to low voltage (BT), the volume of data equivalent to that used for the upstream voltage levels do not enable the use of an identical method (roughly 800,000 HTA/BT transformer substations, 36 million delivery points). Load curves are however necessary for precisely allocating infrastructure costs to the different hour/season categories. In the absence of a panel of measurements of hourly load curves for flows at the level of HTA/BT transformers, Enedis carried out CRE's request for load curve simulations at this BT scope. This simulation functions by aggregation of individual load curves, whose random draw must correspond to the structure observed in users at the level of a diversified sample of BT levels, downstream of an HTA/BT transformer.

Although the input data do not have, for practical reasons, an identical format between each voltage level, the same method is applied from HTB to the BT.

- Estimate of tariff coefficients

Once this scatter plot is obtained, the curve describing the infrastructure cost of grid use by users based on their duration of use is determined. This curve is concave, reflecting the fact that short-use users tend to withdraw more during peaks. Tangent approximation makes it possible to deduce the tariff coefficients relating to subscribed power and energy withdrawn.

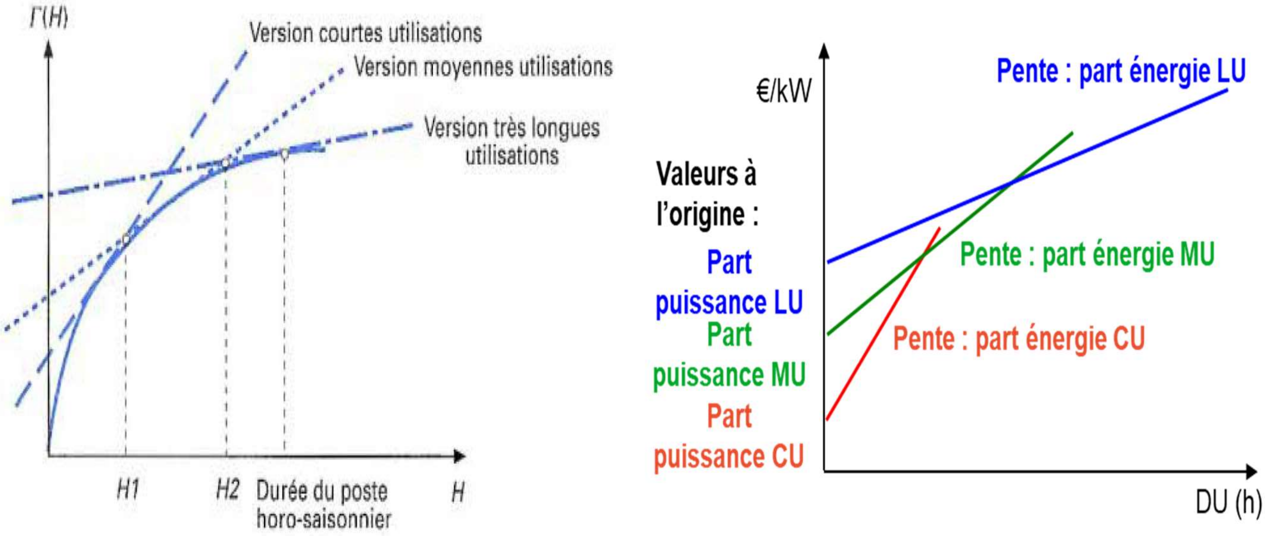

Figure 4 : Approximation of tangents to estimate tariff coefficients (source: Principles of electricity pricing in France by Frédérique Decré and Hervé Chefdeville)

The tariffs so obtained therefore guarantee that each user is billed closely to the costs they generate, this ensuring that TURPE sends a relevant signal to users, giving them an incentive to modify their behaviour so as to optimise the investment needs and the operating expenses of the grids in the medium term.

4. STEP 3: ADJUSTMENT AND ALLOCATION OF ANCILLARY COSTS

The coefficients are adjusted proportionally so as to recover the expenses corresponding to the current infrastructure, which may deviate from the marginal cost of infrastructure development because of economies of scale, inflation and technology.

Two cost categories remain to be taken into account to obtain the withdrawal component coefficients:

- the cost of reserves;
- the cost of power losses compensation.

4.1 Cost of reserves

In TURPE 5, the costs of reserves, corresponding to the costs for the constitution of balancing reserves (frequency control, reconstitution of ancillary services, manual frequency restoration and replacement reserves, reconstitution of margins, interruptibility) as well as voltage control costs, are not explicitly allocated to users during the preparation of the tariff structure, but taken into account to set the tariff level. Implicitly, they are therefore distributed based on a logical identical to infrastructure and power losses compensation costs, including cascading of upstream voltage costs to downstream levels. CRE improved this approach for TURPE 6, with regard to both transparency and the distribution between voltage levels.

Operating reserves are constituted so that the electricity system's resources ready to be mobilised are capable of compensating, continuously, the difference between electricity production and consumption (frequency control) and maintaining voltage in its normal operating range (voltage control).

Because of the necessarily random nature of their power demands, all grid users contribute to sizing of reserves:

- high-power users: even if their grid use is generally foreseeable, their unforeseen individual unavailability is likely to cause a significant imbalance at system level;
- low-power users: their grid use is more volatile. Even when attenuated by diversity, the uncertainty related to these users continuously causes differences between production and consumption.

Moreover, certain technical phenomena, such as those caused by changes in production planning and cross-border exchanges typically occurring on the hour, can cause imbalances requiring the activation of reserves without it being possible to identify the users responsible.

French transmission system interconnections allow these hazards to be diversified at the level of the European continent, considerably reducing the cost for the constitution of operating reserves compared to island electricity systems.

Therefore, given the difficulty in identifying the drivers of the cost for the constitution of reserves, CRE considers that, at this stage, it is not possible to allocate the cost of reserves to each user based on their grid use characteristics.

Therefore, for the construction of TURPE 6, CRE allocates the costs of reserves based on energy withdrawn, regardless of the voltage range. The cost for the constitution of reserves represents €0.10 per kWh withdrawn.

4.2 Cost of power losses compensation

Power losses compensation costs are currently passed on to withdrawals based on the loss rate by voltage level and the purchase price profile for power losses compensation. CRE maintains this methodology for TURPE 6.

The loss rates and unit costs of power losses compensation adopted by voltage level are as follows:

Table 3 : Loss rate by voltage level

Voltage level	Loss rate, including losses of upstream levels
HTB 3	1.5%
HTB 2	2.0%
HTB 1	2.7%
HTA	3.7%
BT	10.1%

Table 4 : Unit cost of power losses compensation by voltage level

€c/kWh	Peak times	Other winter peak times	Winter off-peak times	Other summer peak times	Summer off-peak times
HTB 3	0.11	0.10	0.07	0.08	0.05
HTB 2	0.15	0.13	0.09	0.11	0.07
HTB 1	0.20	0.18	0.12	0.15	0.09
HTA	0.28	0.24	0.16	0.20	0.12
BT	0.75	0.64	0.43	0.54	0.32