DELIBERATION N°2021-13

Deliberation of the French Energy Regulatory Commission of 21 January 2021 on the tariffs for the use of public distribution electricity grids (TURPE 6 HTA-BT)

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 to 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 distribution grids (TURPE tariffs). 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 pubic electricity distribution grids known as TURPE 5 bis HTA-BT (medium voltage – low voltage), entered into effect on 1st August 2018, in accordance with the deliberation of 28 June 2018[1], for a period of roughly three years and succeeded TURPE 5 HTA-BT, which was defined by the deliberation of 17 November 2016 (in the rest of the document, the formulation "TURPE 5 HTA-BT" refers to the TURPE 5 HTA-BT and TURPE 5 bis HTA-BT periods). CRE establishes a new tariff for the use of the public electricity distribution grids, known as TURPE 6 HTA-BT, 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 withdrawal pricing and the pricing of injection. 37 answers were received;

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[1]CRE deliberation no.2018-148 of 28 June 2018 deciding on the tariffs for the use of the public electricity grids in the HTA and BT ranges (medium voltage and low voltage) (https://www.cre.fr/Documents/Deliberations/Decision/Tarifs-d-utilisation-des-reseaux-publics-d-electricite-dans-les-domaines-de-tension-HTA-et-BT)

[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 for the use of the public electricity grids "TURPE 6" (https://www.cre.fr/Documents/Consultations-publiques/Structure-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-TURPE-6).

- 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;
- 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 8 October 2020[6], presented CRE's final proposition for TURPE 6 HTA-BT. It addressed the tariff regulatory framework, particularly the quality of service and innovation, the level of Enedis's expenses and income and the resulting tariff level as well as the tariff structure. 43 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[7], 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 HTA-BT is defined so as to cover Enedis's costs provided that they correspond to the costs of an efficient grid operator. The present deliberation is based in particular on Enedis's tariff proposal, as well as on numerous exchanges with the operator, on internal analyses, external auditors' reports[8] and on feedback from market participants in the different public consultations. CRE also had exchanges with Enedis, its shareholder EDF and the FNCCR (national federation of public service local authorities).

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[9].

A tariff for the energy transition

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

The public electricity distribution grids play 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. Enedis will be directly concerned by the connection of decentralised renewables production, as well as by the development of electric mobility and self-consumption, which will profoundly change the flows in the electricity distribution grids in the upcoming years.

The necessary investments will have to be made while controlling their costs

Within this framework, Enedis announced a major increase in its investments and thus plans to devote €69 billion in 15 years, particularly for the connection of decentralised production, but also to modernise the existing network.

CRE is very attentive to Enedis having the means to meet these new requirements. The challenge for Enedis will be to make the necessary investments while optimising the global cost to operate its network.

Supply quality must remain at a sufficient level

Supply quality in the distribution network regularly improved over these last few years. 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 first be to increase the reliability of outage time measurement by including data supplied by Linky meters, the objectives being stable compared to those set for TURPE 5.

[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)
[5] 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 grids "TURPE6" (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. 2020-017 of 8 October 2020 relating to the next tariff for the use of the public electricity distribution grids (TURPE 6 HTA-BT) (https://www.cre.fr/Documents/Consultations-publiques/prochain-tarif-d-utilisation-des-reseaux-publics-de-distribution-d-electricite-dit-turpe-6-hta-bt)
[7] 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).
[8] An audit of Enedis'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.
[9] Minister's letter: (https://www.cre.fr/content/download/22581/285281)

However, CRE considers that quality of service must be strengthened in areas that are priorities for participants, such as connection times

The quality of service delivered by Enedis plays a major role in the functioning of the mass electricity market. In particular, the deterioration in connection times over the last few years is unjustified and this issue must be the target of a major effort towards improvement.

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, and where the deployment of new infrastructure is becoming increasingly complex.

The challenge for Enedis will therefore be to mobilise new flexibility sources (storage, load shedding, aggregation of decentralised flexibility, electric mobility) to limit network reinforcement to what is strictly necessary.

Enedis must continue to transform and modernise

Enedis must transform, modernise and innovate, in connection with its ecosystem, to continue to be a reference operator among the electricity distribution 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 HTA-BT plans to strengthen Enedis's incentive regulation for that purpose.

The benefits of the Linky programme are in line with expectations

The massive deployment of the Linky programme, which will be completed at the end of 2021, will already over the TURPE 6 period, enable a reduction in non-technical power losses and metering costs and the provision of new services and much more precise data on grid operation.

Building on the initial results observed, Enedis is expected to continue to reap and increase the benefits of smart metering in the long term, and return to customers the associated gains in terms of costs and quality of service. The gains associated with the deployment of smart meters will be duly returned to customers over the TURPE 6 period.

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 bill increases that are too brutal. 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

Enedis 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 Enedis[10] would have led to an average annual increase in TURPE 6 HTA-BT of +3.3% per year over the entire tariff period. This TURPE increase would have led to an average increase in electricity tariffs by almost +1% per year.

Change in expenses to be covered

Enedis's proposal presents a significant increase in capital expenses, due to the growth in investment expenses, but also to its request for an increase in its remuneration.

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

[10] Enedis's proposal updated in June 2020, corrected for the inflation assumption, of the last electricity review communicated by Enedis, and the increase in TURPE HTB specified by CRE's deliberation no. 2020-314 of 17 December 2020, totalling IPC + 0.49% per year

- an audit of Enedis's proposal concerning its operating expenses (excluding purchases related to electricity system operation) 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 8 October 2020 and additional exchanges it had with Enedis, CRE decided to limit the increase in expenses proposed by Enedis. TURPE 6 HTA-BT guarantees Enedis's capacity to lead an ambitious and necessary investment programme for supporting the energy transition and modernising the existing network, and to achieve its digital transformation. The goal is thus to enable Enedis, on the one hand, to 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 Enedis, CRE adopted an operating expense trajectory taking into account:

- an increase in operating expenses related to information systems, to meet the growing needs of the network and users (cybersecurity, energy transition, data, smart grid management, etc.);
- tariff coverage of additional expenses to handle climate events of an exceptional magnitude;
- an increase in staff costs, adopting the staff trajectory proposed by Enedis, as well as the enhancement of profit-sharing, since it is Enedis's teams that enable network transformation and its implementation.

This trajectory also responds to the challenge of controlling bill changes, passing on to customers:

- the gains brought by the deployment of Linky meters: these will be gradual over the TURPE 6 period. At the end of the TURPE 6 period, i.e. in 2024, Linky will enable a drop in operation expenses of €231 million/year compared to 2019, i.e. a 5% gain in Enedis's operating expenses. These gains are related in particular to the drop in metering costs and the costs of small interventions which can henceforth be done remotely; to which are added the gains related to the reduction in fraud and billing errors. The latter should reach €118 million/year in 2024 compared to 2019 (3% of Enedis's operating expenses). €1 billion will thus be saved over the TURPE 6 period. These gains offset the increase in capital expenses generated by the deployment of Linky, which will begin to be passed on to customers during the TURPE 6 period through reconciliation of the smoothing regulatory account (CRL) (-€55 million/year during TURPE 6);
- the drop in production taxes, equal to €120 million/year (0.8% of Enedis's expenses).

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

Capital expenses

As a reminder, Enedis's "network" investments are covered by the tariff depending on completed work, which are fully included 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.

Given the elements of analysis at its disposal and market observations, CRE adopts a margin on assets of 2.5%, stable compared to the TURPE 5 period, and an additional return on regulated equity of 2.3%, down 1.7 points compared to TURPE 5.

The level of these parameters, for which the methodology for determining the value remains unchanged compared to TURPE 4 and 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 will go from an average 31.79% in TURPE 5 bis to an average 26.47% over the TURPE 6 period.

In addition, CRE does not accept the proposal by Enedis to remunerate all assets under construction, and makes several corrections to Enedis's proposal relating to the integration of electrical risers within the concession scope in accordance with the ELAN law[13]. Until presently, these were not included within that scope. These decisions limit the increase in capital expenses.

The average level of Enedis's expenses to be covered for the TURPE 6 period will total an average €14,313 million per year. Therefore, over the 2019-2024 period, it shall increase by an average +0.8% per year, as a result of an average drop in operating expenses of -0.1% per year and an average increase in normative capital expenses of

[11] Audit of Enedis's operating expenses and revenues ((https://www.cre.fr/content/download/22912/288844)

[12] An audit of Enedis's proposal concerning its return on capital for TURPE 6 (https://www.cre.fr/content/download/22911/288838)

[13] Law no. 2018-1021 of 23 November 2018 on changes in housing, land management and digital technology.

2.6% per year, reflecting the major increase in the regulated asset base related to the increase in investments planned and the end of Linky deployment.

Lastly, TURPE 6 HTA-BT provides for a *rendez-vous* clause relating to Enedis' remuneration methodology. This might result in a modification in the tariff trajectory for the last two years of TURPE 6.

Change in quantities distributed and the number of customers

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, the number of customers and subscribed power, on the basis of which tariffs are established so as to recover the projected tariff revenues.

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

- continuous growth in the number of clients (+0.9% per year), continuing with the trend seen;
- stabilisation of volumes supplied over the period (excluding COVID-19 effect), resulting from effects offsetting each other (increase in the number of sites and growth in electric vehicles, offset by a drop in unit consumption related to actions to control energy demand the development of self-consumption). The consideration of the COVID-19 crisis has the effect of decreasing the volumes supplied, mainly at the start of the period, with a return to normal projected in 2024;
- an overall increase in the sum of subscribed power, bolstered by the respective growth dynamics of each customer segment (zero growth for HTA clients, +1.3% per year for BT >36 kVA clients and +0.9% per year for BT ≤ 36 kVA clients).

Lastly, Enedis projects a 4% drop in withdrawals from the transmission network over the TURPE 6 period compared to 2019. This volume effect drives down RTE's toll level. It is due, at the start of the period, to a major drop in consumption because of COVID-19, and at the end of the period to the increase in decentralised production, which offsets the pick-up in consumption.

<u>Change in the tariff level</u>

The change in TURPE 6 HTA-BT arises, in addition to the adopted level of expenses to be covered and the adopted assumptions about the number of clients, subscribed power and volumes supplied, from the reconciliation of the Linky smoothing regulatory account (CRL) as from 2023 and the reconciliation of the CRCP account from the previous tariff period. The CRCP will total an average €153 million, compared to -€21 million/year during TURPE 5, i.e. an almost 1.3% increase in allowed revenue for the TURPE 6 period, reflecting in particular the consequences of the COVID-19 crisis on consumption volumes in 2020.

The average increase, for all customers, in TURPE 6 HTA-BT is +0.91% as at 1 August 2021 and an average +1.39% per year over the entire tariff period, based on an average inflation assumption over the period of 1.07% per year. This change should lead to an average increase in electricity tariffs by almost +0.4% per year.

Against the major growth in investments to ensure grid adaptation to the energy transition, the change in TURPE remains moderate. This moderation is made possible in particular by the consideration of the major tax decreases planned in the draft finance law for 2021, the financial environment favourable to investments in the energy transition and the return to customers of the gains on operating expenses enabled by Linky deployment.

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 HTA-BT, CRE is re-adopting 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. The incentive regulation for expenses related to power losses compensation is re-adopted, but CRE has updated the parameters, particularly the determination of the reference volume, to integrate the drop in non-technical power losses made possible by the deployment of smart meters.

In addition, CRE strengthens the incentive regulation for quality of service, particularly with regard to connection times. It sets the goal for Enedis to shorten its connection times by an average 30% by 2024, in line with the ambitious objectives set out in the industrial and human enterprise programme recently announced by the company.

Lastly, CRE introduces an incentive regulation mechanism for innovation, relating mainly to the quality of data transmitted by Enedis to market participants and Enedis's role in facilitating external innovation, within the framework of the execution of its public service missions.

Tariff structure

CRE builds the tariffs in 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, feasibility 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 system 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 tariffs must therefore be robust and adapted to the evolution of uses associated with the current context of energy and digital transition. In particular, the generalisation of the four time category option the BT ≤ 36 kVA voltage level by 2024 and the introduction of pricing based on long-term marginal grid costs aimed at better reflecting the concentration of costs generated by uses in winter as well as the access cost respond to these challenges.

The tariffs adopted 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 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 distribution grids, and sets the "TURPE 6 HTA-BT" tariff which will enter into effect as from 1 August 2021 for roughly four years.

1.2 Tariff preparation process

1.2.1 Consultation of stakeholders

To establish TURPE 6 HTA-BT, 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[14], 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[15], 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[16], covered the quality of service and actions of grid operators to promote innovation from participants for the electricity sector. 33 answers were received;

[14] 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)
[15] Public consultation no.2019-011 of 23 May 2019 relating to the structure of the next tariffs for the use of the public electricity grids "TURPE 6" (https://www.cre.fr/Documents/Consultations-publiques/Structure-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-TURPE-6)
[16] 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[17], covered mainly the changes to the withdrawal component envisaged by CRE. 38 answers were received.
- the fifth, launched on 8 October 2020[18], presented CRE's final proposition for TURPE 6 HTA-BT. It addressed the tariff regulatory framework, the level of Enedis's expenses and revenues and the resulting tariff level, as well as the tariff structure, quality of service and innovation. 43 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 published a public consultation, launched on 9 July 2020[19], 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 , but possibly afterwards.

In addition, CRE held a workshop in June 2020 with participants having contributed to the third public consultation on the specific topic of Enedis's quality of service.

Lastly, after the fourth public consultation, CRE had exchanges with Enedis. At the end of the fifth public consultation, CRE again had discussions with Enedis, as well as with its shareholder EDF, and the FNCCR.

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[20].

1.2.3 Transparency

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

[17] 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 grids "TURPE6" (https://www.cre.fr/Documents/Consultations-publiques/composante-de-soutirage-des-prochains-tarifs-d-utilisation-des-reseaux-publics-d-electricite-turpe-6)
[18] Public consultation no. 2020-017 of 8 October 2020 relating to the next tariff for the use of the public electricity distribution grids (TURPE 6 HTA-BT) (https://www.cre.fr/Documents/Consultations-publiques/prochain-tarif-d-utilisation-des-reseaux-publics-de-distribution-d-electricite-dit-turpe-6-hta-bt)
[19] 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)
[20] Minister's letter: (https://www.cre.fr/content/download/22581/285281)

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 Enedis's proposal concerning its operating expenses (excluding purchases related to electricity system operation) for the 2021-2024 period[21];
- an audit of Enedis's proposal concerning its return on capital[22].

In addition, after publishing the data and tools used to elaborate the structure of TURPE 5, 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, 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 (high-voltage) user and based on the model of a representative 1,000 pockets for the low-voltage (BT) range). 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.

1.2.4 Scope of expenses covered by the tariff

Article L. 341-3 of the energy code states that "*the public distribution system operator produced from the legal separation imposed on Electricité de France by article L. 111-57 shall transmit, at the request of the Energy regulatory commission, the accounting and financial elements necessary for the commission to decide on the evolution of the tariff level and structure.*" TURPE 6 HTA-BT is determined using the accounting and financial elements submitted by Enedis but it applies to all electricity users regardless of their pubic distribution system operator, in accordance with the equalisation principle.

The differences between the costs borne by local distribution companies (LDCs) and their revenues resulting from the application of TURPE to their clients are compensated by the electricity equalisation fund. Article L. 121-29 of the energy code states that "*an equalisation of electricity distribution expenses is performed in order to distribute among public electricity distribution system operators the expenses resulting from their mission to operate the public networks mentioned in article L. 121-4*".

1.3 Challenges for the TURPE 6 period

In the public consultation of 8 October 2020, CRE presented the main challenges it identified for the TURPE 6 HTA-BT period. The contributors to this public consultation mostly share CRE's positions on the topic.

<u>The energy and ecological transition</u>

The TURPE 6 HTA-BT period (2021-2024) falls within the context of an acceleration of the energy and ecological transition, with a massive increase in renewable electricity production. Enedis will be directly concerned by the connection of decentralised renewables production, as well as by the development of electric mobility and self-consumption, which will profoundly change the flows in the electricity distribution grids.

<u>Investment control</u>

Within this framework, Enedis announced a major increase in its investments and thus plans to devote €69 billion in 15 years, particularly for the connection of decentralised production, but also to modernise the existing network.

The challenge for Enedis will however be to carry out these investments while optimising the overall cost of operating its network in order to ensure control of the TURPE HTA-BT level in the long term.

<u>Supply quality and quality of service</u>

A factor of economic attractiveness, supply quality in the distribution network improved over the last few years, but seems to have reached a plateau recently. Improvements can always be sought, but setting overly ambitious objectives would lead to excessively high costs particularly in the absence of noticeable dissatisfaction of users within the framework of the consultations carried out by CRE. For the upcoming tariff period, the main challenge consists in increasing the reliability of outage time measurement by incorporating Linky data, the goals remaining the same as those set for TURPE 5.

[21] Document published within the framework of the public consultation of 8 October 2020
[22] Document published within the framework of the public consultation of 8 October 2020

The quality of service delivered by Enedis plays a major role in the functioning of the mass electricity market. In particular, the deterioration in connection times over the last few years is unacceptable and this issue must be the target of a major effort towards improvement.

The era of flexibility

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, and where the deployment of new infrastructure is becoming increasingly complex.

The challenge for Enedis will therefore be to mobilise new flexibility sources (storage, load shedding, aggregation of decentralised flexibility, electric mobility) to limit network reinforcement to what is strictly necessary.

Transformation and modernisation

Enedis must transform, modernise and innovate to continue to be a reference operator among the electricity distribution system operators in Europe and in the world.

TURPE 6 accompanies the operator in this transformation, taking the transformation into account for 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, 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. TURPE 6 HTA-BT plans to strengthen Enedis's incentive regulation for that purpose.

The benefits of the Linky programme are in line with expectations

The massive deployment of the Linky programme, which will be completed at the end of 2021, will, over the TURPE 6 period, enable a reduction in non-technical power losses and metering costs, as well as the provision of new services and much more precise data on grid operation.

Enedis is expected to continue to reap and increase the benefits of smart metering in the long term, and return to customers the associated gains in terms of costs and quality of service. The gains associated with the deployment of smart meters will be duly returned to customers over the TURPE 6 HTA-BT period.

Tariff level and structure

Enedis proposed a tariff with a marked increase, due in particular to the increase in investment expenses, but also to its remuneration proposal which would lead to a significant increase in the capital expenses covered by 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.

Moreover, the tariff structure sends grid users economic signals to optimise the overall cost of the electricity system in the medium term. Therefore, pricing based on seasons and the time of day contributes to controlling peak power demand in winter. In that regard, the structure evolution introduced by CRE in the present deliberation, based on the grids' long-term marginal costs and the more extensive use of "four-index tariffs", improves these signals.

CRE 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 HTA-BT is based on the definition, for the upcoming tariff period, of Enedis's allowed revenue and a forecast trajectory of energy withdrawals and injections as well as subscribed power in Enedis's network.

The TURPE 6 HTA-BT tariff also defines a regulatory framework aimed, on the one hand, at limiting Enedis'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 Enedis 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 fixes the projected allowed revenue of Enedis for the 2021-2024 period based on the tariff proposal forwarded by Enedis and on its own analyses. In accordance with Article L. 341-2 of the energy code, the allowed revenue covers Enedis's costs provided that they correspond to those of an efficient operator.

This forecast allowed revenue comprises net operating expenses (net OPEX), normative capital expenses (CCN), and the effects of the adjustment accounts:

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

Where:

- AR: projected allowed revenue for the period;
- net OPEX: forecast net operating expenses for the period;
- CCN: forecast normative capital expenses for the period;
- CRCP: reconciliation of the CRCP balance estimated at the end of TURPE 5 HTA-BT;
- CRL: amounts included in the smoothing regulatory account defined by the regulatory framework for Enedis's smart metering project[23].

The tariff framework guarantees collection of the allowed revenue.

2.1.1.1 Net operating expenses

Enedis's net operating expenses are composed of the expenses related to the electricity system and net operating expenses excluding the electricity system.

The expenses related to the electricity system include: "transmission grid access contract expenses": ("toll" billed by RTE to Enedis, in accordance with TURPE HTB, for withdrawals generated in the transmission network by clients connected to the distribution grid), energy costs for compensation of power losses generated by flows in the distribution network, and lastly the expenses related to amounts billed by RTE to Enedis for the connection of Enedis's distribution substations to the transmission network.

The net OPEX excluding the electricity system operation include gross operating expenses (mainly comprising staff expenses, external procurement, and taxes) minus non-tariff related revenue (mainly comprising contributions received for connection and revenue from ancillary services).

2.1.1.2 Normative capital expenses

Normative capital expenses (CCN) are composed of four elements:

- normative capital expenses related to the Linky project: they include the remuneration and depreciation of the Linky regulated asset base (hereinafter "Linky RAB") as well as accelerated depreciation related to the

[23] Deliberation by the French Energy Regulatory Commission of 17 July 2014 deciding on the incentive regulation framework for ERDF's smart metering system in the BT ≤ 36 kVA voltage level

early removal of the existing meters. These normative capital expensesare determined in compliance with CRE's deliberation of 17 July 2014, relating to the Linky project[24];

- normative capital expenses excluding Linky: the method used to define these capital expenses is described below:
- the remuneration of assets under construction (AuC, i.e. investment expenses made but which have not yet given rise to the commissioning of the assets) relating to distribution substations, in compliance with the terms described in section 2.1.2.3;
- the retreatment for the rolling of electrical risers outside the concession scope into the RAB (excluding Linky) set out in section 3.1.3.4.

With regard to the terms for calculating normative capital expenses excluding Linky, CRE established, since TURPE 4 HTA-BT, a method for calculating normative capital expenses using the capital asset pricing model (CAPM), which it adapts to take into account the specific concession accounts as well as the provisions for renewals constituted by the system operator to ensure the renewal of infrastructure under concession. In its public consultation of 8 October 2020, CRE stated its intention of re-adopting this method. Participants were generally in favour. CRE maintains the terms for calculating the net capital expenses excluding Linky unchanged for TURPE 6. These correspond to the sum:

- for the entire regulated asset base excluding Linky (RAB):
  - of net allowances for depreciation and constitution of provisions for renewal;
  - of a "return on assets", giving the system operator a "reasonable return" since it operates the concessionary network at its own risk, including with regard to the infrastructure delivered by the concession holders.
- for "regulated equity", corresponding to the equity of the system operator actually invested in the activity, of an additional remuneration at the risk-free rate (before tax);
- for any financial borrowings, of an additional remuneration at the risk-free rate (after tax).

2.1.2 Return on capital and coverage of investments

2.1.2.1 Method for calculating remuneration parameters

CRE re-adopts, for the TURPE 6 HTA-BT period, the method used to fix the parameters for the remuneration of assets in effect in TURPE 5 bis HTA-BT which is based on the capital asset pricing model (CAPM), which it adapts to take into account the specific concession accounts as well as renewal provisions set aside by the system operator to ensure renewal of infrastructure under concession.

In addition, CRE commissioned an external consultant to assess the financial parameters for calculating the capital expenses of public electricity system operators and to conduct a critical analysis of Enedis'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 8 October.

2.1.2.2 Method for calculating the regulated asset base (RAB) and regulated equity

2.1.2.2.1 Evolution in the regulated asset base excluding Linky

The RAB excluding Linky is defined as the net book value of assets as at 1 January of each year (excluding Linky assets, financial assets and assets under construction).

The RAB excluding Linky thus evolves mainly in line with investments put in service (including free deliveries of infrastructure) minus asset derecognition and industrial depreciation (excluding Linky).

2.1.2.2.2 Evolution in the Linky RAB

In compliance with the deliberation of 17 July 2014[25], the Linky RAB corresponds to the net book value as at 1 January of the year, of assets put into service within the framework of the Linky project over the period from 1

[24] Deliberation by the French Energy Regulatory Commission of 17 July 2014 deciding on the incentive regulation framework for ERDF's smart metering system in the BT ≤ 36 kVA voltage level
[25] Deliberation by the French Energy Regulatory Commission of 17 July 2014 deciding on the incentive regulation framework for ERDF's smart metering project in the BT ≤ 36 kVA voltage level

January 2015 to 31 December 2021 (including information systems and assets related to pre-generalisation), with the exclusion of assets put into service within the framework of the project experiment and classic electronic meters.

The Linky RAB therefore grows mainly with Linky investments commissioned minus asset derecognition and Linky depreciation covered by the tariffs.

2.1.2.2.3 Evolution in regulated equity

The amount of equity taken into account in the calculation of capital expenses (excluding Linky) must be limited to equity used to fund the assets included in the RAB (excluding Linky). For this purpose, CRE introduced since TURPE 4 HTA-BT the notion of regulated equity to link, for assets excluding Linky, the amount of remunerated equity to only investments made by Enedis for its DSO activity.

Regulated equity is defined as the difference, as at 1 January, between the RAB excluding Linky and the sum of specific concession accounts, renewal provisions, investment subsidies received and, if applicable, financial borrowings attributed to assets excluding Linky[26], to which is added the TURPE 2 regulated equity as at 1 January, as defined in annex 1 of CRE's deliberation of 28 June 2018[27] and reproduced in the present deliberation.

Excluding TURPE 2 regulated equity, regulated equity thus grow in line with investments put into service excluding infrastructure deliveries outside of Linky, and minus derecognition of assets owned by the operator, net deprecation (outside Linky) and renewal provisions covered by the tariff, contributions from third parties received during the year and, if applicable, new financial borrowings attributed to assets excluding Linky.

2.1.2.3 Return on capital for assets under construction

In TURPE 5bis HTA-BT, assets under construction (i.e. investment expenses made but not yet giving rise to the commissioning of assets) were not remunerated.

In its public consultation of 8 October 2020, CRE questioned market participants about the introduction of remuneration of long-cycle AuC at the cost of debt. Enedis and its shareholder are in favour of the remuneration of all assets under construction at the rate of regulated equity increased by the asset margin. Along with other contributors, they call for long-cycle and short-cycle assets to not be dissociated. On the contrary, some contributors consider that that would imply billing customers for Enedis's funding needs, without consideration of the cashflow they may have provided.

For the TURPE 6 HTA-BT tariff period, in line with transmission operators, CRE adopts the mechanism it proposed in the public consultation, i.e. remuneration at the best estimate of the cost of Enedis's debt, i.e. the additional remuneration rate of any financial borrowings as specified in section 3.1.3.1.2. The detail on the assets under construction concerned by this mechanism is presented in section 3.1.3.3.

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[28] and ATRD6[29] 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,

[26] In compliance with the deliberation of 17 July 2014 on the incentive regulation framework for the Linky project, the financial debt contracted by Enedis is allocated to the Linky project up to the debt rate adopted in the calculation of the remuneration rate of the Linky RAB

[27] CRE deliberation of 28 June 2018 deciding on the tariffs for the use of the public electricity grids in the HTA and BT voltage levels (https://www.cre.fr/Documents/Deliberations/Decision/Tarifs-d-utilisation-des-reseaux-publics-d-electricite-dans-les-domaines-de-tension-HTA-et-BT)

[28] 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)

[29] 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)

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. With Enedis'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 HTA-BT period, the following treatment of stranded costs:

- recurring or foreseeable stranded costs are given a tariff trajectory on the basis of an annual envelope (see section 3.1.2);
- coverage of other stranded costs will be examined by CRE on a case-by-case basis, based on substantiated proposals submitted by Enedis.

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 8 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.

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 Enedis to maximise this gain. Enedis therefore keeps 20% of the gain;
- a disposal giving rise to an accounting loss will be examined by CRE, based on a detailed dossier submitted by Enedis.

2.1.3 Principle of the CRCP

The level of the TURPE 6 HTA-BT tariff is defined by CRE based on assumptions about the forecast level of Enedis'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 remuneration rate of regulated equity 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 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 8 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 bis HTA-BT 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 HTA-BT 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 HTA-BT provides for a *rendez-vous* clause, as was the case in the previous tariff, which can be activated by Enedis. 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 HTA-BT changes by at least 1%.

Lastly, TURPE 6 HTA-BT provides for a *rendez-vous* clause relating to Enedis's remuneration methodology. This might result in a modification in the tariff trajectory for the last two years of the tariff period.

2.2.2 Principles of the annual tariff update

Within the framework of TURPE 5 HTA-BT, CRE had decided that, excluding the effects related to the reconciliation of the CRCP, the electricity distribution tariff would change by 2.71% as at 1 August 2017, then according to inflation as at 1 August 2018, 2019 and 2020. In its public consultation of 8 October 2020, CRE stated its intention to smooth the change in TURPE HTA-BT 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.

In its public consultation of 8 October 2020, CRE presented, on the one hand, the average update of Enedis's tariffs excluding the Rf parameter[30], taking into account an illustrative assumption of the tariff level, and on the other hand, a proposal for an update of the Rf parameter. Most contributors were in favour of the direction envisaged by CRE to update the Rf parameter. In order to simplify and improve the readability of the framework applicable to the management of clients under a single contract, the present deliberation bases the update of the Rf parameter on the change in the "grid access component" paid by the DSO to suppliers. The grid access component is specified by CRE's deliberation no. 2018-011 of 18 January 2018 deciding on the component for access to the public electricity distribution grids for the management of clients under a single contract in the HTA and BT voltage levels. As proposed in the public consultation of October 2020, this financial contribution paid by Enedis to suppliers will be modified so as to be adjusted, each year as from 1 August 2021, for inflation.

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

a) the tariffs 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*:

$$Z = IPC + X + K$$

[30] Average amount taken into account for the financial considerations paid to suppliers for their management of clients on behalf of DSOs.

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%;
- IPC 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 0.31% (see section 3.3);
- 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 Rf parameter is updated taking into account the values and methods for updating the grid access component defined by CRE's deliberation no. 2018-011 of 18 January 2018.

In addition, CRE may take into account, during annual updates of TURPE 6 HTA-BT, changes in the incentive regulation of Enedis'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 Enedis'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 2. 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 HTA-BT period are defined in section 2.3.3 of the present deliberation. The accounting data presented by Enedis 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 Enedis and the expenses related to power losses. The consequences of audits conducted by CRE will be included in 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 prepare the forecast revenue of TURPE 6 HTA-BT, 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 Enedis'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 28 June 2018 deciding on TURPE 5 bis HTA-BT[31].

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 K coefficient 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 forecast for year *N* defined by the present deliberation, indexed to inflation and the tariff update of TURPE HTB between 1 August 2021 and 1 August of year *N*;
- the forecast reconciliation of the CRCP balance, for year *N*.

The projected revenues resulting from the application of the tariffs effectively implemented over this period are based on the forecast number of customers, subscribed power and energy volumes supplied described in annex 2 of the present deliberation.

[31] CRE deliberation no. 2018-148 of 28 June 2018 deciding on the tariffs for the use of the public electricity grids in the HTA and BT voltage levels (medium voltage and low voltage) (https://www.cre.fr/Documents/Deliberations/Decision/Tarifs-d-utilisation-des-reseaux-publics-d-electricite-dans-les-domaines-de-tension-HTA-et-BT)

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 bis HTA-BT 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 Enedis bears or benefits from any differences compared to this trajectory.

Given the positive results of this incentive regulation over the last ten years and the favourable feedback from participants to the public consultations of 14 February 2019 and 8 October 2020, CRE is re-adopting this principle for TURPE 6 HTA-BT.

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, Enedis will bear or benefit from any difference compared to the trajectory set for the TURPE 6 period.

2.3.1.2 Incentive regulation for power losses in the distribution grid

Power losses in the electricity distribution network correspond to the difference between all of the injections in the distribution network (RTE injections, injections coming from local distribution companies (LDCs) and injections from decentralised production) and all withdrawals. They are composed of technical power losses (Joule effect in particular) and non-technical power losses. The latter is related in particular to fraud and metering bias.

For the TURPE 5 HTA-BT period, Enedis's power losses represented roughly 24 TWh per year for an average annual amount of 1.1 billion euros over the period. This amount represents approximately 13% of Enedis's annual expenses, i.e. 20% of annual operating costs excluding RTE's toll. The coverage of Enedis's losses is therefore a major financial challenge.

TURPE 5 HTA-BT introduced a mechanism aimed at encouraging Enedis to control the purchase cost of its power losses relating to, on the one hand, the volume of power losses, and on the other hand, the average purchase price of power losses. Indeed, although certain factors, over which Enedis has little influence, have an impact on power losses and the costs (weather conditions and market prices for example), CRE considers that Enedis has levers at its disposal to reduce the cost of power losses.

On the one hand, Enedis can optimise its purchasing strategy to control the price at which it purchases its power losses. On the other hand, some levers can reduce the volumes: investment and grid topology choices and use of Linky data to reduce non-technical power losses.

Considering that the mechanism introduced during TURPE 5 effectively encouraged Enedis to control the volume of power losses and optimise its purchasing strategy, CRE proposed re-adopting this mechanism with small adjustments in its public consultation of 8 October 2020. Participants were mostly in favour of CRE's proposals.

TURPE 6 HTA-BT re-adopts the principles of the incentive mechanism for controlling costs relating to power losses compensation defined by TURPE 5 HTA-BT as well as the associated cap, while updating the definitions of volumes and reference prices:

- for each year of the TURPE 6 HTA-BT period, a reference annual amount of power losses is determined *ex post* based on a reference volume and a reference average cost. The reference volume is established based on the principles stated above, taking into account the quantities effectively injected into the networks. The average reference cost is established using the market prices observed for a predefined reference basket of products;
- the difference between this annual reference amount and Enedis's actual costs for the loss purchase item is 80% covered. The remaining 20% therefore represents a gain for Enedis in the case of lower actual costs, and a loss in the case of higher actual costs, compared to the reference annual amount. The potential loss or gain for Enedis is capped at €40 million/year.
- the calculation methods, and their updates, for the reference volume and price for the incentive regulation relating to losses are presented below and described in a confidential annex (annex 3).

2.3.1.2.1 Incentive regulation for loss volumes

For the TURPE 5 period, the reference volume was determined by the application of a loss polynomial. Since the TURPE 6 period will materialise the gains associated with Linky regarding losses, CRE proposed changing the determination of this reference volume to distinguish between technical losses and non-technical losses. Participants were generally in favour of this development. Enedis however requests for the reference volume of technical losses to be able to be updated during the period. Other participants consider that the objectives to reduce the volume of non-technical losses could be increased, to correspond to the level of gains anticipated in 2014, during the definition of the specific regulatory framework for this project (based on the Linky business plan, termed Linky BP 2014).

The present deliberation defines the overall reference volume for Enedis's losses as the sum, of a reference volume for non-technical losses (roughly 45% of total losses) and another for technical losses (roughly 55% of total losses). This reference volume is applicable as from 2021.

Reference volume for non-technical losses

In order to be able to identify and specifically follow the gains associated with Linky, CRE introduces a reference rate, applied to gross consumption in Enedis's network, to define the reference volume for non-technical losses.

For this reference rate, CRE adopts the following values, calculated using the trajectories of non-technical losses supplied by Enedis.

Table 1 : Trajectory of the reference rate of non-technical losses adopted for the TURPE 6 HTA-BT period

	2021	2022	2023	2024
Reference loss rate adopted	2.9%	2.8%	2.6%	2.5%
Resulting indicative volume of non-technical losses (TWh)	10.9	10.3	9.8	9.4

These trajectories enable the ultimate achievement of the initial target of a drop of 3 TWh in non-technical losses since the start of Linky deployment, as specified in Linky BP 2014. In addition, it should be noted that the Linky BP 2014 did not take into account the absolute minimum timeframes for acting on the volume of non-technical losses after their detection. CRE therefore considers that the reduction trajectory projected by Enedis is relevant and adopts it in its reference rate trajectory over the TURPE 6 period.

Reference volume for technical losses

For the reference volume for technical losses, CRE maintains a polynomial-type formula which corresponds to Enedis's 2020 model for technical losses. Since this polynomial, defined in annex 3 of the present deliberation, is not meant to be changed frequently, CRE does not consider it necessary to project its update during the period.

2.3.1.2.2 Incentive regulation for the purchase price of losses

The principle of the mechanism set up by CRE remains identical to that established for the TURPE 5 HTA-BT 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 HTA-BT, 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 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 HTA-BT 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 price is specified in a confidential annex to the present deliberation (annex 3).

2.3.2 Incentive regulation for investments

2.3.2.1 Incentive regulation for unit costs of investments in the networks

TURPE 5 introduced an incentive regulation for the unit costs of investments in Enedis's distribution networks, in order to ensure optimisation of Enedis's costs of investments in the networks for which it is the prime contract, without compromising the making of infrastructure necessary for the operation, and security of its network.

In its public consultation of 8 October 2020, CRE presented as assessment of the incentive regulation for unit investment costs for TURPE 5. In the light of this positive feedback, CRE proposed:

- to re-adopt the mechanism by extending the scope of incentive to "prefabricated" HTA/BT items;
- to adapt the annual indexation parameters of the reference cost calculation model;
- to pay specific attention to producer connection operations and existing installation surplus operations (self-consumption), which only require a simple operation on the meter.

The great majority of contributors to the public consultation were in favour of maintaining the mechanism and the developments proposed by CRE. Some participants expressed reservations about the method used, in particular concerning the breakdown into four population density zones which they deem inadequate.

CRE considers that the use of "emerald" zones (classification of each type of investment in four population density zones: rural municipalities, small towns, large towns and large cities) serves to not have too many incentive-backed incentive categories, while providing sufficiently accurate models of the cost of infrastructure.

2.3.2.1.1 Recap and assessment of the mechanism in TURPE 5

The mechanism, set up in TURPE 5, covers most of Enedis's network investments. It concerned roughly €1,341 million in investments in 2017 out of a total €3,767 million, all categories combined, €1,275 million for 2018 and €1,308 million in 2019 (these last two amounts being provisional). Enedis's investments concerned by this mechanism break down into 20 categories.

The mechanism is based on the definition of a reference cost model for infrastructure put into service by Enedis, taking into account:

- their technical characteristics: the infrastructure is thus grouped into 20 categories (5 different infrastructure types in 4 geographical zones to take into account the technical specificities resulting from certain local characteristics such as population density);
- a trend in costs over time: the target unit costs of each year of the tariff period have been determined based on (i) a relevant basket of reference indexes, so as to exclude external effects and thus evaluate only Enedis's performance, (ii) specific change factors (anticipation of regulatory developments affecting the level of unit costs for example) and (iii) a productivity objective.

For each year, the difference between the total cost of infrastructure commissioned and the total theoretical cost of this same infrastructure is evaluated. The total theoretical cost is calculated using the reference unit cost model applied to the volume of actual investments.

This difference, positive or negative, reflects the operator's efficiency as concerns the actual level of investments. It is shared between the operator and network users:

- the investments concerned are included in Enedis's regulated asset base (RAB) at their real value, subject to inspections CRE may perform into the efficient and careful nature of the costs incurred. The capital expenses related to these investments therefore remain covered on the basis of actual spending. Therefore, the end consumer covers the operator's performance over the asset's lifetime through higher or lower normative capital expenses;
- a bonus or penalty is then applied, through the CRCP, equivalent to 20% of the difference between the total theoretical cost corresponding to the volume of investments made for infrastructure and the total actual cost recorded. This mechanism therefore encourages Enedis to control its unit investment costs, without challenging the level of investments made. This annual incentive is capped at +/- €30 million per year.

The TURPE 5 deliberation projected, within each of the 20 infrastructure categories targeted, a model of each investment cost by:

- a fixed portion (which does not depend on the year of commissioning);
- where applicable (for investments not including connections), a variable share depending on the length of the line (overhead or underground) concerned;
- an annual update coefficient for unit costs (the same for all infrastructure categories, changing each year).

The values of these parameters were estimated using the costs of investments commissioned between 2021 and 2014 for infrastructure not including connections, and between 2012 and 2015 for connections.

In its public consultation of 8 October 2020, CRE presented an assessment of this regulation over the first two years (2017 and 2018 provisional). The analyses conducted by CRE as well as the feedback from a contributor to the public consultation revealed that Enedis's performance had been overestimated, given the integration, in the calculation of unit costs incurred, of connections of "existing installation surplus". However, most of these procedures, relating self-consumption operations, do not involve work (only a meter operation, not giving rise to any asset creation) and therefore cannot be considered as investments. Their integration within the scope of incentive regulation for the years 2017 and 2018 artificially reduced the unit costs attributed to the segment "producer connections ≤ 36 kVA", generating an unjustified bonus of €5.5 million, which CRE will return to users during the calculation of the definitive CRCP balance for the TURPE 5 period.

After this retreatment, Enedis globally beat the reference trajectory for incentive-backed investments, by 2.8% in 2017 and 5.7% in 2018, i.e. an overall average outperformance of 4.2%. The end consumer will benefit, through lower normative capital expenses over the lifetime of assets, from a gain of €114 million$_{2019}$ compared to the reference trajectory.

2.3.2.1.2 Adaptation of the mechanism for the TURPE 6 period

For the TURPE 6 HTA-BT tariff period, CRE re-adopts this mechanism. In order for users to benefit from the performance achieved during TURPE 5, the reference level for each of the 20 categories identified in TURPE 5 is adjusted based on the data from the years 2016 to 2019.

In particular, concerning the segment relating to producer connection, CRE fixes the reference cost level excluding self-consumption connections not giving rise to an asset creation.

Moreover, CRE includes, within the scope of incentive regulation, the prefabricated HTA/BT items whose reference unit costs are determined using the costs of investments commissioned over the 2016 – 2019 period.

With regard to the annual indexation parameters of reference costs, CRE indicated that it was endeavouring to simplify the specific update factors. Participants were generally in favour of this development. However, Enedis considers that any additional costs related to the asbestos regulation should be isolated and neutralised during incentive regulation calculations for the TURPE 6 period.

The analysis of the change in unit costs during the TURPE 5 period showed that anticipating the additional costs related to any changes in regulation is particularly difficult given the lack of visibility. Moreover, it is the responsibility of Enedis to increase productivity, by re-organising its processes or better negotiating contracts with its providers, to better offset these possible additional costs. Therefore, for the TURPE 6 tariff period, and in line with the update factors adopted for GRDF in the ATRD 6 tariff, CRE adapts the incentive regulation mechanism, no longer taking into account specific update factors in the determination of the reference unit costs. However, CRE maintains the use of a reference basket of indices so that these costs best reflect the economic conditions of the period.

The values of the parameters and the annual average update coefficients for unit costs over the 2021-2024 period are defined in a confidential annex to the present deliberation (annex 4).

2.3.2.2 Incentive for controlling costs for "non-grid" investments

In TURPE 5 HTA-BT, CRE introduced a mechanism incentivising Enedis 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, vehicles and some information systems (IS).

By nature, these expense items are in fact likely to give rise to trade-offs between investments and operating expenses. Therefore, this mechanism encourages Enedis to globally optimise all of its expenses in these three items. In consists in defining, for the tariff period, a trajectory of the estimated capital expenses for this type of investment, which would be excluded from the scope of the CRCP. Enedis keeps all of the gains or losses made during the tariff period. At the end of the tariff period, the effective value of assets will be taken into account in the RAB, which, for the following tariff periods, will allow the sharing of gains or additional costs with users.

With regard to the scope of investments concerned by the incentive regulation mechanism, the context related to Linky deployment led, during TURPE 5, to excluding roughly 50% of Enedis's IS investments from the scope of this regulation. These non-incentive backed expenses were therefore fully taken into account through the CRCP.

In its tariff proposal, Enedis requests for a part of its new IS investment projects (related in particular to cybersecurity, data publication, grid digitalisation, regulatory developments, smart grids, and the redesign of obsolescent IS, and representing roughly 80% of Enedis's IS investments) to be excluded from the scope of incentive regulation for "*non-grid*" investments because they present a level of risk or uncertainty justifying their coverage through the CRCP.

In its public consultations of 14 February 2019 and 8 October 2020, CRE proposed re-adopting the incentive regulation mechanism for controlling "*non-grid*" investments, considering that the feedback on its effectiveness was still too limited for reliable conclusions to be drawn. With regard to the scope of IS investments to be excluded from the incentive regulation mechanism, CRE proposed that, unless there is a detailed justification of the relevance of coverage through the CRCP of costs associated with a specific project, the rule remains inclusion of IS investments within the scope of incentive regulation. Most participants that answered the public consultations were in favour of the mechanism proposed by CRE. The reservations expressed were particularly related to the possibility of leaving Enedis some latitude by excluding a part of its IS investments from the scope of incentive regulation.

Given all of these elements, CRE re-adopts the incentive mechanism for controlling “*non-grid*” investment costs described above for TURPE 6 HTA-BT. In particular, with regard to IS investment expenses, CRE considers that these costs can generally be controlled by operators and can be traded for operating expenses, and therefore, as a general rule, they should be maintained within the scope of the incentive mechanism.

However, Enedis supplied justifications concerning uncertainties, at this stage, surrounding the expenses associated with certain IS projects. CRE considers in particular that in the light of growing challenges relating to cybersecurity and digitalisation of the operator’s activities, it is relevant to exclude certain IS investments from the scope of incentive regulation. These investments which will not be subject to the incentive mechanism, presented in annex 5, represent 18% of Enedis’s IS investments.

During the TURPE 6 HTA-BT period, the capital expenses for incentive-backed “*non-grid*” assets will be calculated using the forecast values defined in the present deliberation. At the end of the tariff period, CRE will analyse the trajectories of the commissioning of the investments concerned in order to ensure that any gains made during the tariff period do not result in higher expenses for the following tariff periods, because of certain project delays for example.

The estimated amount of “*non-grid*” investments subject to this incentive regulation for Enedis is an average €310.0 million per year, i.e. roughly 7.8% of the total investments planned in the operator’s trajectory for TURPE 6 HTA-BT.

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 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, in particular, 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, CRE proposed the scope of the CRCP to adopt for TURPE 6 HTA-BT in its public consultation of 8 October 2020. Contributors to the public consultation were divided concerning CRE’s proposal. Some of the participants in particular, did not agree with the removal of concession fee payments and the expenses relating to Enedis’s contributions to the electricity equalisation fund (FPE) from the scope of the CRCP. These participants state that these items are neither foreseeable nor controllable by Enedis.

In the light of the responses from contributors to the public consultation, CRE updates the consideration of concession payments and expenses relating to Enedis’s contributions to the FPE in the CRCP.

Regarding the pace of renewal of concession contracts, several contributors to the public consultation stated that they were not in favour of CRE’s approach to remove this item from the scope of the CRCP, arguing in particular the fact that Enedis could then be encouraged to reduce the renewal pace of its contracts. Therefore, in order to avoid this bias, the trajectory effectively subject to the incentive mechanism will be re-calculated *ex post* based on the number of contracts effectively renewed, in comparison with the renewal trajectory anticipated by Enedis within the framework of its tariff proposal.

As concerns the FPE, Enedis’s contributions will be calculated by two distinct methods, the flat-rate method and the account analysis method. The expenses relating to the flat-rate method are foreseeable since the resolution of disputes in connection with this method, with formulas and coefficients being reviewed in 2019. On the contrary, the contributions calculated by the account analysis method are not foreseeable at this stage, since CRE’s analysis exercise is scheduled for some time in 2021. Therefore, only the part of Enedis's contribution to the FPE produced from the account analysis method applied to certain DSOs is included within the scope of the CRCP.

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

- for expenses and other related items:
    - normative capital expenses borne by Enedis, with the exception of those concerned by the incentive regulation mechanism for "*non-grid*" capital expenses;
    - expenses related to the TURPE HTB payment for Enedis's distribution substations, 100% covered;
    - expenses related to the connection of distribution substations to the public transmission grid, 100% covered;
    - expenses related to loss compensation, 100% covered, and subject moreover, to an *ad hoc* incentive regulation (see section 2.3.1.2);
    - The expenses related to arrears corresponding to TURPE, 100% covered;
    - the expenses related to the contribution paid to suppliers for the management of clients with a single contract in accordance with CRE's deliberation no. 2018-011 of 18 January 2018, as well as the expenses corresponding to customer management by suppliers prior to 1 January 2018, within the limit of the maximum amounts per connection point likely to be taken into account and fixed by deliberation no. 2017-239 of 26 October 2017, 100% 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 (smart grid counter), 100% covered;
- revenues and other related items:
    - Enedis's tariff revenues, 100% covered;
    - contributions from users received for connection, 100% covered;
    - differences in revenues related to unplanned changes in the tariffs for ancillary services, 100% covered;
    - the amounts determined by CRE as part of the revenues resulting from contracts signed with the EDF group with third parties concerning smart metering, 100% covered.
- the financial incentives generated by the incentive regulation mechanisms:
    - the incentive for losses in the distribution grid (see section 2.3.1.2);
    - for the unit costs of network investments (see section 2.3.2.1);
    - specific to the Linky smart metering project, in compliance with CRE's deliberations of 17 July 2014[32] and 23 January 2020[33];
    - for quality of service and supply quality (see section 2.4), for all the indicators concerned[34].

CRE extends the CRCP mechanism to the following items:

- the gains from real-estate and land asset disposals (see section 2.1.2.2.2), 80% covered (this means that Enedis will have a 20% incentive on this item);
- the expenses associated with the implementation of flexibility: the level of these expenses is too hard to foresee at this stage for it to be relevant to define a trajectory for this item. If the use of a flexibility source replaces a network investment, this choice moreover is in line with the incentive sent to Enedis (the capital expenses being included fully in the CRCP);
- the financial incentives generated by the incentive regulation mechanism for the quality of data provision (see section 2.5.3);

[32] Deliberation by the French Energy Regulatory Commission of 17 July 2014 deciding on the incentive regulation framework for ERDF's smart metering system in the BT ≤ 36 kVA voltage level
[33] Deliberation by the French Energy Regulatory Commission no. 2020-013 of 23 January 2020 deciding on the incentive regulation framework for Enedis's smart metering system in the BT ≤ 36 kVA voltage level (Linky) for the 2020-2021 period
[34] Apart from "appointments scheduled and missed by Enedis" and "number of penalties paid for non-provision of the connection at the date agreed on with the user" indicators, for which penalties are paid directly to the customers by Enedis

- any penalties generated by the incentive regulation for the promotion of external innovation (see section 2.5.4);
- the operating expenses associated with the restoration of the network following weather hazards exceeding a reference trajectory, based on the terms described in section 3.1.2.3.2, in connection with the non-renewal by Enedis of its storm insurance coverage contract as from 2021.

In addition, CRE modifies the conditions of coverage of the following items which were fully covered in the CRCP in TURPE 5 HTA-BT:

- concerning the expenses related to Enedis's contributions to the FPE, only the portion of these expenses resulting from CRE's analysis of the accounts of DSOs that so request it remains eligible for the CRCP. The portion of these expenses resulting from the application of the flat-rate method is no longer eligible for the CRCP;
- the expenses related to concession fees in compliance with the previously specified terms;
- stranded costs (net book value of assets demolished) are only eligible on a case-by-case basis, in line with the tariff coverage terms adopted in section 2.1.2.2.1.

2.4 Incentive regulation for quality of service and continuity of supply

2.4.1 Incentive regulation for quality of service

The incentive regulation for Enedis's quality of service aims to improve the quality of the service provided to distribution system users in the fields deemed particularly important for the proper functioning of the electricity market. It is a pillar of the tariff regulatory framework, which ensures that economic efficiency is not achieved to the detriment of the services provided by the networks.

In its public consultations of 19 October 2019 and 8 October 2020, CRE presented an assessment of the incentive regulation mechanism for quality of service since 2009. In that assessment, CRE noted that the quality of operators' service had improved in the fields of particular importance for network users, even though some expectations of participants are not met, particularly concerning connection.

In their responses, market participants shared this positive view and approved CRE's approach concerning the pursuit of ambitious objectives regarding quality of service.

2.4.1.1 Recap and assessment of the incentive regulation mechanism in TURPE 5

For the TURPE 5 period, Enedis's quality of service was steered by 12 indicators with financial incentives (including 2 indicators for which the penalty is paid directly to the user). 29 other indicators are followed and published by Enedis, but without financial incentives. In addition to these indicators, there are also the specific indicators for monitoring the quality of service of the Linky smart metering project, i.e. 8 indicators with financial incentives and 9 others followed but with no incentives.

The financial incentives are based on the establishment of a reference objective. Enedis's performance, based on compliance or non-compliance with this objective, generates bonuses or penalties. These are capped.

Enedis prepares and publishes an annual qualitative analysis of its performance on its website.

Since the introduction of a regulation for quality of service in 2009, Enedis has achieved, for the majority of the issues followed, a level of performance in line with the objectives set and with almost continuous improvement. In particular, CRE notes the following points:

- good performance by Enedis concerning the indicators related to the reliability of the electricity balance ("energy adjusted and normalised under Recotemp" and "differences in the Enedis's balancing perimeter") and concerning the rate of commissioning with a visit at the date requested by the client;
- the maintenance of a high level of performance concerning the rate of transmission to RTE of half-hourly measurement curves and the availability rate of the supplier portal.

This overall performance enabled Enedis, over the TURPE 5 HTA-BT period, to receive an overall bonus of €3.4 million. These results build on the performance achieved by Enedis since 2009. It received a bonus every year, with the exception of 2019. In 2019, Enedis received an overall penalty of €146 k, mainly due to poor performance for the indicators relating to responses to claims within 15 days (penalty of €1.1 million), as well as the rate of indexes metered and self-metered per half-year period (penalty of €0.7 million).

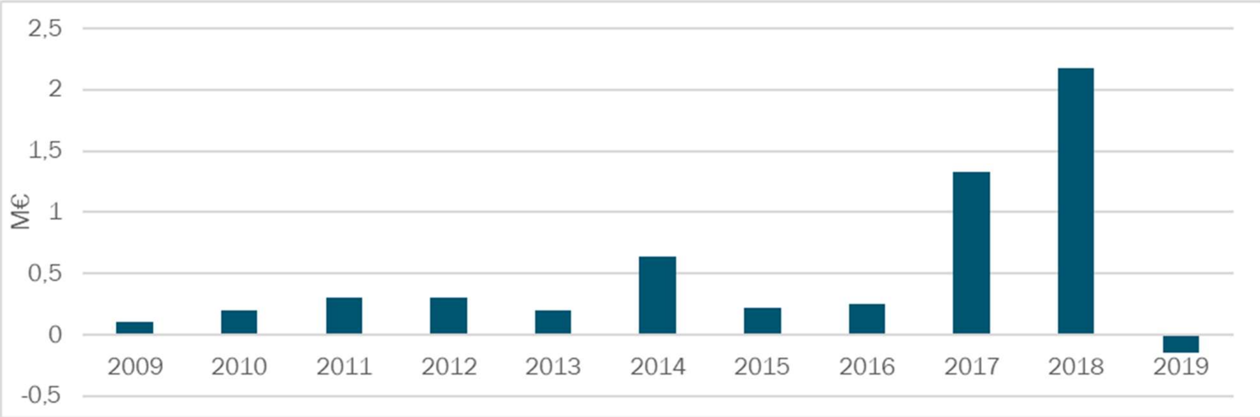

Figure 1 : Financial volumes associated with incentive regulation for Enedis's quality of service (excluding Linky)

However, despite this overall good performance, Enedis's performance is not satisfactory in two areas: connection and claims processing. Over the TURPE 5 period, CRE notes in particular:

- non-satisfactory performance concerning connections: the average connection timeframes are lengthening and the performance for incentive-backed indicators is unstable;
- a deterioration in the indicator "rate of response to claims within 15 calendar days".

2.4.1.2 Adaptation of the mechanism for the TURPE 6 tariff period

Globally, over the last few tariff periods, following and applying incentives to quality of service indicators have led to the improvement of Enedis's performance in the fields targeted. To remain effective, the indicators and associated incentives must however evolve regularly, depending on the results obtained and new challenges that emerge.

In that regard, and building on the directions envisaged in the public consultation of 17 October 2019, CRE proposed in the public consultation of 8 October 2020 re-adopting the incentive regulation for quality of service with small adjustments based on the feedback and the needs of grid users.

The quality of service indicators adopted for TURPE 6 as well as the associated financial incentives are described in detail in Annex 6 of the present deliberation.

2.4.1.2.1 Simplification of the mechanism

CRE proposed in its public consultation:

- for incentive-backed indicators: the switch to follow-up without incentives if the incentive no longer seems relevant (this is the case in particular of three indicators that have become obsolete with Linky deployment, but whose follow-up remains necessary for the few clients not equipped with Linky meters by the end of TURPE 6);
- for the indicators followed: for the purpose of readability, the merging of certain indicators followed without altering the quality of information transmitted by Enedis;

With the exception of one participant that expressed reservations concerning the elimination of the incentive on the indicator for commissioning, most participants are in favour of these proposals.

CRE adopts the simplifications envisaged in the public consultation.

The following incentives, previously backed by incentives, presented in detail in Annex 6, are switched to the list of indicators only followed, so that the level of Enedis's performance will still be measured:

- the rate of commissioning with a visit at the date requested by the client;
- the rate of electricity indexes metered or self-metered per half-year period;
- the rectified index rate for BT ≤ 36 kVA customers.

2.4.1.2.2 Reinforcement of the mechanism

Implementation of an asymmetrical regulation

CRE proposed, for the two indicators whose quality improved during TURPE 5 and whose performance level is now considered satisfactory (deadline for submitting measurement curves to RTE, availability rate of supplier/third party portal), to introduce asymmetrical incentives by eliminating the bonus and maintaining the penalty.

Most market participants were in favour of this proposal. However, certain system operators are opposed to the introduction of asymmetrical incentives that could result in “punitive” regulation.

CRE considers however that the introduction of this type of incentive is relevant given the record of bonuses generated by the two indicators identified. Asymmetrical incentives in fact serve to maintain at the level achieved, once it is deemed satisfactory, Enedis’s performance incentive while avoiding windfall effects for operators.

For the TURPE 6 period, CRE introduces an asymmetrical regulation on the following indicators, described in detail in annex 6:

- availability rate of the function “interrogation of data useful for the service order” of the supplier and third-party portal;
- deadline for transmitting to RTE the half-hourly measurement curves of each balance responsible party.

Connection times

In its public consultation, CRE proposed strengthening the regulation for connection times, with the replacement of the current incentive-backed indicator relating to compliance with the date agreed on with the client in a connection agreement, by an incentive on the average timeframe for making connections.

Most contributors are in favour of CRE’s proposal. Some participants however shared their surprise concerning the level of the objectives proposed by CRE, deemed insufficient given the commitment announced by Enedis in its Industrial and human enterprise project which consists in cutting connection times by half by 2025.

The connection time objectives for each segment presented in the public consultations follow a regular downward trajectory to reach, at the end of the TURPE 6 period, a level consistent with the times observed in 2015-2016 and reachable by Enedis over the TURPE 6 period. These trajectories propose an average drop of almost 20% in the average connection time at the end of the TURPE 6 period compared to the times recorded for the year 2019.

CRE considers that given the ambitions presented by Enedis after the public consultation, it is relevant to strengthen the level of the objectives. However, the incentive regulation must not penalise Enedis’s approach but on the contrary encourage the achievement of this objective with the goal of a major improvement in quality of service.

Therefore, CRE decides to strengthen the trajectory of objectives so that they reach an average drop in connection times of almost 30% by the end of the TURPE 6 period compared to 2019.

Moreover, during the exchanges with Enedis, CRE noted that the “Large producer” business in the BT > 36 kVA and HTA voltage levels were not included within the scope of the indicator calculated by Enedis.

CRE considers that this business must be included within the scope of the indicator, since they were already subject to financial incentives under the regulatory framework of TURPE 5.

Therefore, CRE decides to include, in the scope of the indicator with a financial incentive “Average timeframe for conducting connection operations by connection category”, the “BT > 36 kVA and HTA producers” and to set the trajectory of objectives based on the same principles as those of the other segments presented above.

Lastly, a participant expressed reservations about the use of the issue date of the bill as a marker signifying the completion date of the connection.

Initially, CRE wished to establish a framework for the connection procedure from the client’s agreement on the connection quote up to the end of the connection work, these markers delineating a phase covering all of the actions under the primary responsibility of Enedis. However, at this stage, the work end date is not systematically filled in by Enedis in the IS for work management.

Therefore, the present deliberation:

- introduces an indicator with a financial incentive based on an average connection timeframe and no longer on compliance with a deadline set initially by Enedis, for which the calculation and incentive terms are presented in annex 6;
- introduces the follow-up of an equivalent indicator for provisional connections, which were not followed in TURPE 5, with the prospect of adding an incentive to it during the next tariff period;

- requests Enedis to improve data capture for all connection steps so that they can be used during the next tariff period.

Processing of claims

In its public consultation of 8 October 2020, CRE proposed, for the TURPE 6 period, strengthening Enedis's incentive to improve the processing of claims it receives, and in particular the quality of the responses to the claims through the proposal to financially incentivise the indicator “rate of multiple claims filtered”.

In addition, on this same issue, CRE proposed eliminating the indicator relating to the number of claims received by the DSO directly from users.

All contributors that expressed their views on this issue are in favour of CRE's proposal. However, several participants question the relevance of eliminating the indicator on the number of claims received directly by Enedis, considering in particular, that it correctly reflects the quality of the transmission channels set up by Enedis for its users.

CRE considers that, since Enedis, through other indicators followed, already provides the monthly volumes of claims it receives (coming from suppliers or users), this indicator provides little useful information.

Given these elements, CRE decides:

- to attach a financial incentive to the indicator “rate of multiple claims filtered”, based on the terms described in annex 6;
- to follow the indicator “rate of response to claims within a timeframe exceeding 30 calendar days by type and category of user” instead of the indicator relating to the follow-up of responses to claims within a timeframe exceeding 60 days”;
- in agreement with the national energy mediator, to follow the number of admissible claims received by the mediator concerning Enedis's activity;
- to eliminate the indicator “number of claims received by the DSO directly from users”.

Supplier relationship

In its public consultation of 8 October 2020, CRE proposed, for the TURPE 6 period, to add a financial incentive to two indicators relating to the availability of the special supplier line.

Almost all participants are in favour of CRE's proposal. Some participants however consider that the trajectory of the objective of the indicator relating to accessibility of the special supplier line (also called “urgent business line”) is too ambitious given call centre standards.

Over the TURPE 5 period, the indicator relating to the acceptability of the special supplier line remained stable (roughly 93%). CRE considers that the current level must improve particularly because of the urgent nature of this line. Moreover, since it is an inter-company line, CRE considers that Enedis is less exposed to misdirected calls than call centres in direct contact with users. CRE therefore considers that the trajectory of objectives presented in the public consultation (objective set at 96.5% in 2024) is relevant.

In the light of all of these elements, for the TURPE 6 period, CRE decides:

- to attach a financial incentive to the indicators “accessibility rate of the special supplier line” and “call rate on the special supplier line with a wait time lower than 90 seconds”, according to the terms described in annex 6;
- to eliminate the follow-up of the indicator currently followed relating to wait time lower than 120 seconds.

Other adaptations

In its public consultation, CRE also proposed:

- the introduction of two indicators followed to measure the quality perceived by users of connection operations on the one hand, and of services excluding connection, on the other hand;
- the introduction of a follow-up indicator for the performance in loss forecasting, based on the difference between forecast losses and actual losses in anticipation of the switch to the target system with a loop loss model and the change in the calculation and incentive terms for the indicator relating to non-allocated energy.

Most participants were in favour. CRE therefore adopts this proposal for the TURPE 6 period.

2.4.2 Incentive regulation for continuity of supply

Supply quality is an essential counterpart to the tariffs paid by users. As of TURPE 3, CRE established incentives for the improvement of continuity of supply, and more specifically, on the average outage duration. The incentive regulation for supply quality aims to guarantee that the productivity gains made by Enedis do not come at the expense of a drop in supply quality.

Enedis's supply quality is followed through indicators, which may be subject to a financial incentive or a simple monitoring. The financial incentives are based on the establishment of a reference objective. Enedis's performance, depending on compliance or non-compliance with this objective, generates bonuses or penalties.

During the TURPE 5 period, Enedis's continuity of supply was followed through 5 indicators with financial incentives:

- average outage duration in BT (B criterion);
- average outage duration in HTA (M criterion);
- average outage frequency in BT (F-BT criterion);
- average outage frequency in HTA (F-HTA criterion);
- compensation for long outages.

2.4.2.1 Annual average duration and frequency of power outages

2.4.2.1.1 Average outage duration in BT (B criterion)

For the TURPE 6 period, CRE proposed, in its public consultation, prioritising the reliability of the B criterion through a gradual automation of its calculation, taking Linky data into account in particular. Participants globally agreed with this objective. Some participants however request an acceleration in the calendar for implementing the new calculation method.

CRE maintains, for the TURPE 6 period, the financial incentive on the indicator for the average outage duration in BT, keeping the objective at the level set for the last year of TURPE 5 (i.e. 62 minutes). The calculation and incentive terms of this indicator remain the same as for the TURPE 5 period and are specified in annex 7.

In parallel, CRE defines a binding timetable for the automation of the calculation of the B criterion. The timetable proposed in public consultations aims for automation before the end of the TURPE 6 period, which will enable the new calculation methodology to be used for the TURPE 7 period. CRE therefore requests Enedis to comply with the following timetable for the implementation of the new calculation methodology for the B criterion:

- 2020: defining the rules for the collection and control of Linky data for their integration in the calculation of the B criterion;
- 2021: audit by CRE of the conditions for calculating the B criterion by Enedis, which will also serve to assess the impact of Linky data on the average outage duration;
- 2021: gradual deployment of processes for correcting outage durations and the number of clients impacted by an outage for the C5 connection points (BT ≤ 36 kVA, and single contract) by comparison of Linky data and the data resulting from the historical method;
- 2022: use of the data for C4 connection points (BT > 36 kV, and single contract) equipped with smart meters;
- end of 2024: implementation of a process for automatic calculation of the B criterion and use of Linky meter data.

2.4.2.1.2 Other incentive-backed indicators for continuity of supply

With regard to the M, F-BT and F-HTA criteria, CRE proposed in its public consultation to continue improvement in the objectives by applying the method used during TURPE 5. Participants were generally in favour. However, Enedis requests for the slope of the trajectory proposed for objectives to be more gradual to reflect its actual capacity for improvement.

CRE re-adopts for the TURPE 6 period the three other indicators with incentives for measuring continuity of supply:

- average outage duration in HTA (M criterion);
- average outage frequency in BT (F-BT criterion);

- average outage frequency in HTA (F-HTA criterion).

The calculation and incentive terms of these indicators remain the same as for the TURPE 5 period and are specified in annex 7.

Given the analysis of the performance achieved over the last few years, the objectives set for Enedis are as follows:

Table 2 : Objectives set for Enedis for the M criterion, F-BT crieterion and F-HTA criterion indicators

Unit	2021	2022	2023	2024
Average annual outage duration in HTA (M criterion)	42.1 minutes	41.8 minutes	41.5 minutes	41.2 minutes
Average annual outage frequency in BT (F-BT criterion)	1.72 outages	1.60 outages	1.47 outages	1.34 outages
Average annual outage frequency in HTA (F-HTA criterion)	1.87 outages	1.73 outages	1.58 outages	1.43 outages

In order to limit the financial risk for Enedis related to the establishment of the four abovementioned incentives, the overall cap/floor of financial incentives (bonuses/penalties) borne by the operator is maintained at ± €83 million per year.

In addition, CRE maintains the follow-up during the TURPE 6 tariff period of other indicators relating to continuity of supply in Enedis's serving area, without financial incentives. The corresponding list is specified in section 3.2 of annex 7.

In addition, CRE maintains its request to LDCs serving over 100,000 clients and to EDF SEI to implement a follow-up of the four indicators relating to the average annual outage duration in BT and in HTA and to the average annual outage frequency in BT and in HTA, based on the definitions specified in section 4 of annex 7.

2.4.2.2 Compensation for long outages

The mechanism implemented during TURPE 5 required all DSOs to pay compensation to clients whose power supply was cut for a consecutive duration exceeding five hours. This compensation must be paid regardless of the origin of the power cut. In particular, when the supply cut is due to a failure in the public transmission grid, the compensation is paid to the consumer by the DSO, but RTE reimburses the DSO concerned.

The compensation paid to consumers is based on a flat rate, broken down by voltage level and by five-hour outage periods. In the case of supply cuts of a duration higher than five hours due to a failure in the public grids it operates, the DSO pays the customers concerned[35] the following compensation per five-hour period, within the limit of 40 consecutive five-hour periods:

- for customers connected in the BT low-voltage level whose subscribed power is lower than or equal to 36 kVA, the compensation is €2 (before tax) per kVA of subscribed power per 5-hour outage period;
- for customers connected in the BT low-voltage level whose subscribed power is higher than 36 kVA, the compensation is €3.5 (before tax) per kVA of subscribed power per 5-hour outage period;
- for customers connected in the HTA medium-voltage level, the compensation is €3.5 (before tax) per kVA of subscribed power per 5-hour outage period.

In order to take into account extreme situations, in the case of a cut of more than 20% of end customers connected directly or indirectly through the transmission network, the abovementioned compensation is not paid to the customers concerned.

The payment of this compensation or reduction does not deprive customers of the right to seek the liability of their public grid operator through procedures of ordinary law.

In order to limit their financial exposure, LDCs and EDF SEI maintain the possibility, in the case of cuts related to an exceptional event defined in section 1 of annex 7, of reducing the amounts of compensation applicable, compared to the normal compensation defined above. The amounts of reduced compensation applicable in these situations must be proportional to the amounts of normal compensation and must not be lower than 10% of these amounts. The amounts of normal compensation remain applicable for cuts other than those related to an exceptional event

[35] This mechanism concerns only withdrawal points. It is applicable to all DSOs (Enedis, LDCs and EDF SEI).

defined in section 1 of annex 7. Each DSO must, where applicable, publish and transmit to CRE the proportional reduction factor it implements.

With regard to the financial handling of compensation paid by Enedis, TURPE 5 provided for the integration in the operating expenses, of a trajectory with a financial incentive up to a certain capped amount above which the sums paid by Enedis were compensated through the CRCP.

Enedis was not able to reach the objectives set by TURPE 5 and therefore received major penalties. During the public consultation of 8 October 2020, CRE questioned participants about an increase in the level of coverage by TURPE taking into account Enedis's performance (trajectory with an incentive and cap above which the sums paid are covered in the CRCP). Participants' feedback on this matter is divided, some of them wishing for better coverage of these expenses which tend to increase with recent climate events, while other participants consider that Enedis must be further encouraged to minimise these expenses.

CRE re-adopts this mechanism for the TURPE 6 period. In order to take into account Enedis's performance during TURPE 5, CRE modified the coverage levels of the mechanism. The *ex ante* coverage is fixed at €75 million per year (this amount is included in the net operating expenses presented in section 3.1.2) instead of €38 million/year in TURPE 5. The cap above which the sums paid by Enedis are compensated through the CRCP is fixed at €117 million (instead of €80 million in TURPE 5).

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 customers.

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;<
- 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.

In its public consultations of 14 February 2019 and 8 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. On a whole, and although some responses proposed increasing or reducing the level of transparency targeted by CRE, the participants comment the organisation by Enedis of a consultation on its R&D topics at the start of the tariff period.

Given all of these elements, for the TURPE 6 HTA-BT tariff period, CRE establishes incentive regulation based on the following principles:

- the incentive for controlling costs relating to Enedis's R&D expenses is maintained, with the possibility for Enedis to revise this trajectory halfway into the tariff period so that it may have more flexibility to adapt its programme. At the end of the TURPE 6 HTA-BT period, Enedis will present to CRE a financial report on R&D, and the amounts not spent during the period will be returned to customers (through the CRCP), while the operator will bear the costs of exceeding the trajectory;
- transparency and verification of the efficiency of R&D spending are reinforced through two exercises, with the format to be determined conjunctively between CRE, Enedis 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 Enedis 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;

- Enedis will consult market participants before summer 2022 concerning the major research topics they intend to develop.

Trajectory of R&D expenses for TURPE 6

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

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

Table 3 : Enedis's forecast R&D expenses for TURPE 6 (subsidies deducted)

In €million$_{nominal}$	2021	2022	2023	2024	Total 2021-2024
Enedis's R&D budget proposal for TURPE 6 (subsidies deducted)	56	56	57	58	**227**

This overall budget of €227 million for TURPE 6 represents a 1.5% increase compared to the overall trajectory of TURPE 5 HTA-BT. Enedis's programme for TURPE 6 will be based, building on the TURPE 5 period, on two topics "Energy transition" and "Industrial performance", to which the expenses related to smart grids will be integrated transversally. CRE adopts the trajectory presented by Enedis.

CRE will review, at the end of the tariff period, the sums actually spent by Enedis and will return to users, through the CRCP, any difference between the projected and actual trajectory, if Enedis 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, enabling them, during the tariff period, to obtain additional funding. Therefore, Enedis 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.

Enedis did not make use of the smart grid mechanism over the 2017-2019 period, devoting almost one-third of its R&D budget, i.e. over €50 million over the 2017-2019 period, to the funding of demonstrators. Enedis states that the €3 million threshold is too high for most of the projects that may be concerned.

In its public consultations of 14 February 2019 and 8 October 2020, CRE proposed lowering the current threshold of the smart grid counter to €1 million for Enedis, in line with the threshold set for all gas operators for the next tariff period, 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 smart grid IS investments to also be examined within the framework of the smart grid counter.

Given all of these elements, for the TURPE 6 HTA-BT period, CRE re-adopts a smart grid counter with the same term operating terms as during the previous tariff period. However, the eligibility threshold for this mechanism is lowered to €1 million and the expenses associated with IS smart grids are included in the scope of eligible expenses. Any possible integration of additional operating and normative capital expenses related to the development of smart grids will therefore be studied within the framework of the annual update of the tariff.

2.5.3 Data publication

In TURPE 5 HTA-BT, the provision of data was not a specific topic in the regulatory framework. Some indicators in connection with data provision however, were already followed, but did not cover all of participants' needs in that area. Moreover, the incentive regulation specific to the Linky project introduced two indicators relating to provision of metering data.

CRE 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 that in mind, and given the needs expressed by participants, CRE proposed, in the public consultation of 8 October 2020, an incentive regulation framework for the provision by Enedis of data useful to grid participants. Contributors to the consultation are mostly in favour of the implementation of such an incentive regulation. Some participants however, expressed reservations about the level of certain objectives deemed insufficiently ambitious, particularly regarding the business client segment, and warned CRE about the need to ensure that the indicators measure not only the transmission but also the quality of data.

CRE agrees with the need to encourage Enedis to transmit reliable data and built indicators with that in mind. CRE introduces, for the TURPE 6 HTA-BT period, an incentive regulation mechanism which will penalise Enedis in the case of non-compliance with deadlines and completeness of the data published, regarding consumption data (index and load curves), for both the mass market and the business market, which were identified as priority data. In particular, following participants' comments about the establishment of an indicator during the public consultation, CRE modifies the objectives as well as the terms for calculating the incentive.

CRE introduces:

- for the mass market:
    - an indicator for the provision by Enedis of load curves produced by Linky meters: the availability rate on D+1 of Linky load curves;
- for the business market, equivalent indicators to those adopted for the mass market:
    - transmission rate on D+1 of indices and other meter data;
    - rate of successful telemetered readouts for billing for meters BT > 36 kVA;
    - load curve transmission rate on D+1 for the business market.

In addition, CRE maintains, for the mass market, the incentive on the two incentive regulation indicators for the quality of service specific to the Linky project:

- rate of successful daily telemetered readouts;
- rate of publication by Ginko of actual monthly indices;

To these incentive-backed indicators is added the indicator, followed during TURPE 6, relating to the timely transmission of intraday data.

The detail on the calculation method for these indicators and penalty application is presented in annex 8. The objectives set are those proposed during the public consultation except for the indicator for the provision on D+1 of load curves for the business segment, for which additional exchanges served to refine the objective trajectory in connection with Enedis's performance and participants' expectations.

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 October 2019 and October 2020, to establish an incentive regulation for compliance by Enedis with deadlines for carrying out certain actions identified as priorities to promote innovation pursued by market stakeholders. Most participants are in favour of the implementation of this mechanism.

Therefore, the present deliberation introduces for the TURPE 6 HTA-BT period an incentive regulation mechanism for compliance with implementation deadlines by Enedis for 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 HTA-BT period in line with legislative and regulatory developments and priority work identified by CRE, and after consultation of market participants. The priority actions could relate, in particular, to the integration of flexibility, the adaptation of connection assessments to new uses, 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;
- 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 Enedis is capped at €10 million/year.

No action is integrated as of the implementation of this mechanism in TURPE 6 HTA-BT. Actions will be integrated in the mechanism during the period following the process described above.

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

3.1 Level of expenses to be covered

3.1.1 Enedis's tariff proposal

Enedis puts forward the need for a major increase in investments over the TURPE 6 HTA-BT period (+16% between 2019 and 2024 excluding Linky) in order to enable connection of renewables and electric vehicle charging infrastructure, the maintenance of a high level of supply quality and the development and modernisation of its information systems.

In parallel, it intends to control its net operating expenses (excluding purchases related to electricity system operation), with the goal of returning in 2024 to the level reached in 2019, in constant euros. Enedis estimates that the productivity gains so made regarding controllable expenses will total 1.9% per year over the TURPE 6 HTA-BT period.

Enedis therefore requests a total of expenses to be covered[36] of €14,577 million in 2021, i.e. €711 million (+5.1%) more than expenses seen in 2019, followed by an annual average increase of +0.9%. This increase would result in an average tariff increase of an average +3.0% per year, in constant euros, over the entire TURPE 6 HTA-BT period.

Tariff impacts of COVID-19

The tariff proposal submitted by Enedis 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 supplied 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, Enedis estimated the downward effect of the anticipated consequences of the COVID-19 crisis on the energy volumes supplied for the TURPE 6 period, expecting a return to normal in 2024 and affecting the level of certain expense items (HTB toll and losses) and that of its tariff revenues. The other repercussions of the COVID-19 crisis on Enedis'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, Enedis 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 TURPE 6, so that grid users benefit from these productivity gains over time.

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

CRE commissioned Schwartz & Co to audit Enedis's net operating expenses (excluding expenses related to electricity system operation). Work was conducted between April and July 2020. The auditor's report, based on the initial version of Enedis's proposal, was published together with the public consultation of 8 October 2020.

This audit provided CRE with a good understanding of Enedis's operating expenses and revenues as well as its "*non-grid*" investments over the TURPE 5 HTA-BT period. It also thoroughly analysed the operating expenses and the

[36] Sum of normative capital expenses, expenses related to the electricity system and net operating expenses excluding expenses related to the electricity system

forecast "*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 Enedis early July 2020. Enedis was therefore able to comment on the results of the auditor's work.

In its public consultation, CRE had considered a range with the "high end" being the trajectory of operating expenses as proposed by Enedis, and the "low end" being the trajectory recommended by the consultant, to which was added the €18 million/year adjustment relating to the end of the storm insurance subscription proposed by Enedis.

Following the public consultation, discussions continued between Enedis 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 Enedis and its own analyses.

3.1.2.2 Inflation trajectory

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

However, in compliance with what it stated in its public consultation, 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 4 : Inflation rates adopted by CRE for the TURPE 6 HTA-BT period

	2020	2021	2022	2023	2024
Forecast inflation adopted in the public consultation	0.4%	1.4%	1.6%	1.7%	1.7%
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 Net operating expenses excluding purchases related to the electricity system

3.1.2.3.1 Enedis's proposal

Enedis's proposal totals an average €4,752 million/year over the TURPE 6 HTA-BT period. The net OPEX excluding purchases related to electricity system would increase in 2021 by +€129 million, i.e. +2.9% compared to 2019 actual expenses. Expenses would then increase over the 2021-2024 period by an average -0.7% per year.

The forecast net operating expenses excluding purchases related to the electricity system presented by Enedis for the TURPE 6 HTA-BT period are presented in the table below:

Table 5 : Enedis's proposal – net OPEX excluding expenses related to the electricity system

€million$_{nominal}$	*2019 Actual*	2021	2022	2023	2024	Average 2021-24
Net OPEX excluding expenses related to the electricity system – revised proposal *Evolution (%)*	*4,673*	4,802 *+ 2.8%*	4,784 *- 0.4%*	4,717 *- 1.4%*	4,706 *- 0.2%*	4,752
- of which Purchases and services (excluding capitalised production)	*2,619*	*2, 424*	*2,374*	*2,355*	*2,396*	*2,387*
- of which Staff expenses	*2,798*	*2,908*	*2,919*	*2,923*	*2,943*	*2,923*
- of which capitalised labour	*- 650*	*- 692*	*- 692*	*- 702*	*- 694*	*- 695*
- of which Taxes	*754*	*805*	*821*	*833*	*845*	*826*

- of which "Other operating expenses"	*284*	*456*	*448*	*449*	*459*	*453*
- of which Non-tariff-related income	*- 1,133*	*- 1,100*	*- 1,084*	*- 1,141*	*- 1,242*	*- 1,142*

The year 2019 is marked by an exceptional provision write-back (€140 million) for the electricity equalisation fund, which artificially reduces the "Other operating expenses" heading for that year and generates a large step between the actual figure for 2019 and Enedis's proposal for the year 2021. When adjusted for this element, the 2019-2021 difference is due mainly to the following items:

- staff costs, up +3.9%, i.e. +€110 million, mainly because of an increase in pension costs;
- within purchases and services:
  - concession fees, up +14.1%, i.e. +€40 million, in connection with the deployment of the new concession contract model;
  - computer and telecom operating expenses, up +5.4%, i.e. €24 million, the result of a growth in IS developments;
  - purchases of services (excluding real estate and IS), down -15.8%, i.e. -€110 million, due to the end of the storm insurance subscription (see below), but also in connection with the end of meter reading visits made possible by Linky;
- the increase in capitalised labour by +6.3%, i.e. +€41 million, in net operating expenses;
- within other operating expenses, the increase in "other revenues and expenses" (+€47 million, i.e. +127%), category comprising different expense sub-items seeing increases (software fees, supplier credit relating to the transmission portion of arrears, etc.).

3.1.2.3.2 CRE's analysis

The auditor's analysis covered the initial tariff proposal submitted by Enedis on 7 July 2020.

Table 6 : Net OPEX (excluding expenses related to the electricity system) – Enedis's propsal and auditor's adjusted trajectory

In €million nominal	Actual 2019	2021	2022	2023	2024
Final trajectory of net OPEX excluding expenses related to the electricity system proposed by Enedis	4,673	4,802	4,784	4,717	4,706
Auditor's adjusted trajectory[37]		4,652	4,607	4,538	4,464
Difference with Enedis's proposal		- 150	- 178	- 178	- 242

The adjustments recommended by the auditor (an average €187 million/year excluding the impact of the 2020 draft finance law (DFL)) mainly cover the headings "Purchases and services" (21%), "Staff costs" (25%) and "Other operating expenses" (43%).

Market participants are divided concerning the trajectories proposed respectively by Enedis and the auditor, but they are mostly in favour of the preliminary orientations which CRE presented in the public consultation. Some participants consider that the IS expenses proposed by Enedis are in line with the context of the energy transition and correlate with the efforts necessary to achieve it, particularly in terms of the quality of the data transmitted. Other participants drew CRE's attention to the necessity to take into account the impacts of the health crisis on inflation and on the 2021 DFL in Enedis's net OPEX trajectories. Lastly, other participants considered that the drop in non-technical losses made possible by the massive deployment of Linky meters, smaller than expected, justified adopting the trajectories of the gains resulting from Linky BP 2014 and recalculated by the auditor, and not Enedis's forecasts (see below).

CRE, within the framework of work conducted since the public consultation of 8 October 2020, made a certain number of readjustments to the trajectory proposed by the auditor. The main adjustments it adopts compared to Enedis's proposal are presented below.

Drop in production taxes:

[37] This trajectory takes into account all of the adjustments proposed by the auditor in its report after the update of the inflation assumption.

The draft finance law (DFL) for 2021 plans for a drop in production taxes, particularly on the regional levies and property taxes. This drop in taxes will be permanent and will therefore apply to the entire tariff period.

The present deliberation takes into account the associated drops in expenses for Enedis for the years 2021 to 2024.

Given the timetables for the publication of the DFL and of its public consultation, CRE did not include 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 7 : Impact of the DFL on the net OPEX trajectory of Enedis

In €million$_{nominal}$	Actual 2019	2021	2022	2023	2024
Final trajectory of net OPEX excluding expenses related to the electricity system proposed by Enedis	4,673	4,802	4,784	4,717	4,706
Auditor's adjusted trajectory		4,652	4,607	4,538	4,464
2021 DFL impact		- 108	- 114	- 120	- 126
Auditor's adjusted trajectory incl. 2021 DFL impact		4,544	4,493	4,419	4,339

Purchases and services (net of capitalised production):

The trajectory proposed by the auditor is lower by roughly €40 million per year on average compared to that of Enedis (-1.9%). The adjustments recommended concern mainly the items "IS and Telecom" (an average -€17 million/year, -3.5%), "Other purchases" (an average -€9 million/year, -28.9%), "Real estate" (an average -€12 million/year, -3.4%) and "Tertiary and services" (an average -€3 million/year, -0.5%).

Regarding the item "Other purchases", the adjustment covers more specifically "other different expenses (miscellaneous purchases)", whose increase was deemed insufficiently justified and which were maintained by the auditor at the average level of 2017-2019.

CRE's analysis

CRE agrees with the auditor's conclusions concerning the unjustified increase in the "Other purchases" item and therefore adopts the auditor's trajectory, which leads to an average adjustment of -€9 million/year for the TURPE 6 period.

Concerning the "Tertiary and services" item, the adjustment mainly covers the "Vehicle" sub-item. The adjustments concerning this sub-item as well as the "IS and Telecom" and "Real estate" items, which were subject to a TOTEX-type analysis (investment and operating expenses analysed globally), are presented further on.

Staff expenses:

The trajectory proposed by the auditor is lower by roughly €47 million per year on average compared to that of Enedis (-1.6%). The adjustments recommended concern mainly the items "Remuneration", "Other staff expenses" and "Executive and non-statutory staff":

- with regard to the "Remunerations" item, the adjustment (an average -€14 million/year, -0.9%) results from an assumption of trajectories of the rate of the NMW and the age and job-skill coefficient[38] corresponding to the average historic values observed, identical to that recommended by the auditor for RTE. The auditor does not challenge the staff trajectory envisaged by Enedis;
- with regard to the "Other staff expenses" item, the adjustment (an average -€14 million/year, -4.7%) results from different assumptions and calculation methods, particularly concerning the expenses associated with paid leave and the time-saving account and profit-sharing mechanisms.
- lastly, the adjustment concerning the "Executive non-statutory staff" (an average -€13 million/year, -11.0%) results from a reconstitution by the auditor of the trajectories of average paid staff and associated expenses, without adjusting the staff, but with different indexation assumptions.

CRE's analysis

[38] 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.
Age and job-skill coefficient: this index reflects the evolution in Enedis's average labour cost.

CRE's analysis of the "Remuneration" item is based on the staff trajectory proposed by Enedis. In line with the decisions adopted for the gas tariffs of 2019, CRE does not adopt the auditor's adjustment but Enedis's proposal regarding the assumptions of the development of national minimum wage (NMW). However, CRE adopts the adjustment associated with the auditor's age and job-skill coefficient, which represents an average -€6 million/year drop in Enedis's proposal, distributed among the different items (of which -€4 million/year for the "Remuneration" item).

With regard to the "Other staff expenses" item, for which the recommended adjustment is mainly related to profit-sharing and supplementary retirement contributions, CRE takes into account negotiations in progress relating to a new framework agreement on profit-sharing, and therefore adopts Enedis's proposal.

Lastly, given the clarifications provided by Enedis on its remuneration policy for non-statutory workers, CRE does not adopt the adjustment proposed by the auditor concerning the "Executive and non-statutory staff" item.

All of the adjustments adopted by CRE for staff expenses therefore represents an average -€13 million/year for the TURPE 6 period.

Other operating expenses (excluding FPE provisions):

This item increased in Enedis's proposal (+€33 million in 2021 compared to the actual 2019 amount excluding FPE provisions, i.e. +8%).

The trajectory proposed by the auditor is lower by roughly -€81 million per year on average compared to that of Enedis (-17.9%). The adjustments recommended mainly cover the items "Compensation paid to clients", "Other proceeds and expenses", "Net book value of assets demolished" and "Net provisions":

- with regard to the "Compensation paid to clients" item, the adjustment (an average -€28 million/year, -30.7%) proposed by the auditor aims to encourage Enedis to improve its performance for this item, which contains in particular, the compensation for long outages (see sections 2.4.2.2 and 2.4.2.3);
- with regard to the "Other proceeds and expenses" item, the adjustment (an average -€23 million/year, -27.8%) results from a lack of justification by Enedis of the increase in its proposal for most of the sub-item components, which leads the auditor to align the TURPE 6 trajectory with that of the actual 2019 amounts adjusted for inflation;
- with regard to the "Net book value of assets demolished", the adjustment (an average -€19 million/year, -25.6%) breaks down into two distinct parts:
  - the auditor considers that the 2019 level adopted by Enedis to define its proposal is not relevant and proposes re-aligning the trajectory with that of the average of the last five years;
  - the auditor does not adopt the additional band proposed by Enedis to cover the consequences of the sticky snow episode, which it considers integrated in the historical trend;
- with regard to the "Net provisions" item, the adjustment (an average -€8 million/year, -106.5%) results from the fact that the auditor considers that, since provisions are written back subsequently and are therefore only an accounting exercise which should be neutral for end customers, it is not legitimate to take them into account to fix the TURPE 6 HTA-BT level. Therefore, with the exception of the provisions relating to the exceptional increase in the concession fee generated by the signing of the amendment to the Montpellier protocol[39], for which the associated expenses are clearly identified moreover, the auditor fixes all of the provisions concerned by this item at zero.

CRE's analysis

CRE considers that it is relevant to set the trajectory of the "Compensation paid to clients" item so as to encourage Enedis to improve its performance regarding long outages. Nevertheless, the reference chosen to set this trajectory appears to be too ambitious given Enedis's performance record. CRE therefore adopts an intermediate trajectory, which corresponds to an adjustment of an average -€15 million/year to Enedis's proposal (i.e. -16.7%).

CRE adopts most of the adjustments proposed by the auditor for the "Other proceeds and expenses" item, for which Enedis did not provide sufficient justification about the level of its proposal. Nevertheless, CRE considers that the adjustment proposed by the auditor concerning disposal proceeds is not completely necessary given the mechanism for partial restitution to the customer of the gains of real estate disposals set up by TURPE 6 HTA-BT (see section

[39] In 2013, the signing of the Montpellier agreement between ERDF and FNCCR introduced a smoothing mechanism form the R2 portion of the fee, limiting the significant variations in the fee from one year to another. In 2017, the signing of the national framework agreement between FNCCR, France urbaine, Enedis and EDF extended this smoothing mechanism for concessionary authorities signatory to an extension amendment, effective as from 2018. This amendment enables concessionary authorities to benefit from the maintenance of the smoothing mechanism until the entry into effect of the new contract and up to 20 June 2021 at the latest, in return for entering into negotiations for the renewal of the contract. The economic benefit of this Montpellier smoothing is provisioned as from the implementation of the amendment then paid one month after the signing of the contract if this occurs before 30 June 2021. The adjustment of the *Net provisions* item exceeds 100%, because a net write-off of +€2 million related to the last payment associated with this protocol remains in 2021 and is not adjusted.

2.1.2.4.2), and only adopts the part of the adjustment concerning non-real estate asset disposals. In sum, the adjustment adopted for the “Other proceeds and expenses” item represents an average -€15 million/year compared to Enedis’s proposal.

With regard to the “Net book value of assets demolished” item, Enedis increased, following the public consultation, its proposal by +€9 million/year to take into account the net book value of meters removed within the framework of the Linky project. CRE analysed this additional request. CRE considers that it is set to define the forecast trajectory of the “Net book value of assets demolished” item of TURPE 6 HTA-BT based on a long-term historical reference adjusted for any exceptional events, while taking into account the effects of metering projects, which are henceforth identifiable and foreseeable. The resulting trajectory represents an adjustment of an average -€7 million/year compared to Enedis’s revised request (i.e. -12.7%). The coverage of other exceptional effects likely to deviate from this trajectory will be addressed in an *ad hoc* examination (see section 2.1.2.4.1).

CRE shares the analysis of the auditor concerning the “Net provisions” item and considers that the constitution and write-back of provisions must be a neutral accounting exercise for the tariff in the long term. CRE therefore adopts the associated adjustment.

CRE does not adopt the adjustment proposed by the auditor for the “*Staff tariff*”, for which the calculation method does not sufficiently take into account the increases in the regulated sales tariffs occurring in 2020, and their impact on the associated expenses for Enedis.

All of the adjustments adopted by CRE for this item therefore represents an average -€58 million/year for the TURPE 6 period.

Non-grid investments and associated operating expenses:

For three sub-items in Enedis’s tariff matrix, the investments associated with operating expenses are subject to an incentive on the “non-grid” capital expenses (see section 2.3.2.2). The goal of this incentive regulation mechanism, which concerns information systems, real estate and vehicle expenses, which can cause arbitration between investment expenses and operating expenses, is to encourage Enedis 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 for Enedis at the start of the tariff period, with a 100% incentive, such that the gains or losses are fully kept by the operator.

Therefore, the auditor also analysed the forecast trajectory of investments associated with these three sub-items in Enedis’s proposal, in order to assess its efficiency, and proposed some adjustments both for operating expenses and for investments[40].

With regard to the IS and Telecommunications item, the trajectory proposed by the auditor is lower by roughly -€27 million per year on average compared to that of Enedis (-3.6%). The auditor considered that Enedis should have the objective of reaching in 2024, the same level of expenses as that of 2019. The operator therefore has the means of pursuing its digital transformation, through an increase in IS expenses during the tariff period, but must ensure that the performance level reached does not deteriorate over time.

The adjustment proposed by the consultant to the overall scope was then distributed between the operating expense trajectories (an average -€17 million/year, -3.5%) and the investments associated with the IS and Telecom item (an average -€10 million/year, -3.9%).

With regard to the Real estate item, the trajectory proposed by the auditor is lower by roughly -€15 million per year on average compared to that of Enedis (-3.4%). The adjustments recommended result from an item-to-item analysis by the auditor, leading:

- for operating expenses, to a trajectory lower by an average -€12 million/year (-3.4%) compared to that proposed by Enedis, in order to encourage Enedis to align itself, by 2024, more with the performance of other French businesses in terms of occupancy density of premises;
- for investments, to a trajectory lower by an average -€3 million/year (-4.0%) compared to that proposed by Enedis. This adjustment to investments results from:
    - - €23 million/year for the years 2023 and 2024 (i.e. an average -€11 million/year over the period), associated with the deferral to the TURPE 7 HTA-BT period of the relocation project for the *Agences Conduite Réseau* (ACR) units initially scheduled for 2023 and 2024 in Enedis’s proposal, but deemed insufficiently developed by the auditor;

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

- an average +€8 million/year between 2022 and 2024 associated with the forecast additional investments generated by the site concentration recommended by the auditor.

With regard to the Vehicles sub-item (included in the "Tertiary and services" item), the trajectory proposed by the auditor is lower by an average -€3 million/year compared to that proposed by Enedis. The auditor considers that Enedis's proposal presents an unjustified increase in vehicle maintenance costs. With regard to investments, the auditor does not propose any adjustments, considering that the increase related to the electrification of Enedis's light vehicle fleet is offset by productivity efforts concerning the size of this fleet.

CRE's analysis

CRE agrees with the auditor's approach concerning the IS and Telecom item and considers that, despite the growth in needs, Enedis must mobilise potential sources of productivity gains and that the tariff level must encourage it to prioritise its projects. Nevertheless, to take into account the change in needs, CRE adopts an intermediate solution consisting in adopting the initial increase proposed by Enedis in 2021 (+5.9%), then considering a constant level over the TURPE 6 period (excluding Linky and inflation). This approach leads to:

- adopting an adjustment of an average -€12 million/year to the operating expenses compared to Enedis's proposal (i.e. -2.5% of these expenses);
- keeping Enedis's proposal concerning investments.

CRE considers, regarding the Real estate item, that the gains made possible by an occupancy density strategy for Enedis's premises are overestimated by the auditor. Therefore, CRE only adopts the adjustment proposed by the auditor concerning facility management services as well as other adjustments to minor items, which present an unjustified increase, i.e. an average -€4 million/year compared to Enedis's proposal (i.e. – 1.0%). Concerning investments, CRE shares the auditor's position, according to which, for the purpose of controlling the item, up sharply over the period, all real estate projects envisaged by Enedis cannot be executed during the same tariff period. CRE however, does not agree with the auditor's proposal to defer the project to renew the *agences de conduite du réseau* (network control centres). This project is in fact linked to the core business of Enedis and its implementation is a priority.

CRE considers however, that the project to create an in-house training campus must not be considered as a priority, since it is not critical for the proper implementation of Enedis's activities. It thus adopts an adjustment of an average -€8 million/year compared to Enedis's proposal (i.e. – 9.8%).

CRE shares the auditor's analysis concerning the operating expenses and investments associated with the Vehicles sub-item. In that regard, CRE:

- adopts an adjustment of an average -€3 million/year to the operating expenses compared to Enedis's proposal;
- does not adopt any adjustment to the trajectory of investments associated with light vehicles.

All of the adjustments adopted by CRE for these three categories represents within the scope of cumulated operating expenses and investments, an average -€27 million /year compared to Enedis's proposal (i.e. – 2.1%). These adjustments break down into:

- an average -€19 million/year for operating expenses (i.e. – 2.1%);
- an average -€8 million/year for investments (i.e. – 2.1%).

Storm insurance mechanism

Since 2021, Enedis has a storm insurance coverage contract which covers operating expenses for grid restoration (labour costs and purchases of work and material) in the case of high-intensity weather hazards whose impact exceeds €50 million in operating expenses and within the limit of €275 million over the duration of the contract (five years). The fixed premium associated with this insurance, which has never been activated since 2012, is €18 million/year.

This insurance premium was covered by the TURPE 5 tariff trajectories, similar to the other operating expenses associated with weather incidents (which break down into €30 million/year in the heading "Purchases and Works" and €10 million/year related to staff expenses for the repairs). The net book value of assets demolished associated with climate incidents was covered, for the corresponding amount, through the CRCP.

Enedis proposed in its revised proposal to not renew the storm insurance coverage contract and requests the implementation of a mechanism for coverage of the associated risks by the tariff. The mechanism envisaged would consist in:

- maintaining a trajectory to cover the purchase costs of work and labour to the extent of Enedis's request of the TURPE 5 trajectory (€40 million/year);
- taking into account in the CRCP the amounts that would deviate from this reference by more than €20 million, upward or downward (the threshold of €60 million, which corresponds to the actual amount of 2019, was exceeded only once in ten years with the storm Klaus);
- in return, the storm insurance would not be renewed, and the expenses to be covered would drop by the amount of the storm premium (-€9 million in 2021, then -€18 million as from 2022).

CRE's analysis

CRE considers that Enedis's proposal to not renew its insurance contract is relevant. Therefore, it decided to introduce a mechanism such as that described above, whose functioning is similar to that set up to cover EDF SEI from storm hazards. This mechanism would be effective as of early 2021. However, given the expiry data of the present insurance contract (mid-2021):

- the trajectory would continue the amount of the contribution for the first half of 2021 (i.e. €9 million);
- moreover, if an exceptional event occurring in the first half of 2021 generated the payment of a compensation by the insurance policy, CRE would make sure to take these proceeds into account tin the calculation of the amounts to be covered by the CRCP.

Tariff coverage of the net book value of assets demolished during such incidents will be treated in compliance with the mechanism adopted in section 2.1.2.2.1.

3.1.2.3.3 Gains brought by the deployment of smart meters

The Linky project, whose deployment started early 2015, consists in replacing all of the mass market meters (BT ≤ 36 kVA) by smart meters by 2024. At this stage, almost 28 million smart meters have been deployed, as planned in the project's initial timetable.

This project, whose industrial, technological and financial magnitude is an exception in Enedis's activities, was subject to a technical and economic analysis by CRE in 2014, which led, on the one hand, to deciding to launch the project, and on the other hand, to setting the tariff trajectories for it.

This exercise served to identify the forecast costs associated with the Linky project, but also the gains expected for Enedis. As a reminder, these gains are related to:

- the reduction of non-technical power losses: reduction in fraud and billing errors;
- drop in metering costs: replacement of meter visits by telemetering;
- drop in the cost of small interventions which can now be remotely controlled;
- to a lesser extent, the drop in technical power losses, and progress in the duration of outages thanks in particular to better knowledge of the grid.

Since the end of the massive deployment of Linky meters is scheduled for the end of 2021, the efficiency gains associated with meter deployment must be duly returned to customers at the end of the TURPE 6 HTA-BT period. Taking into account these gains is even more important since the TURPE 6 HTA-BT period will see the start of reconciliation of the Linky smoothing regulatory account (CRL) (as from 2023).

The reality of these gains was estimated by analysing Enedis's tariff proposal based on the following methodology:

- reconstruction of "Inertial" (counterfactual scenario, i.e. without the deployment of Linky) and "Linky" scenarios, by revising the assumptions of the 2014 business plan and taking into account actual elements to date (inflation, number of meters installed, purchase cost of power losses), which serves to update gain estimates;
- evaluation of the gains made (over the 2014-2019 period) or forecast (over the 2020-2024 period) by comparing the 2014-2024 trajectories (actual and forecast) with the inertial scenario;
- comparison of the gains made or forecast with net "theoretical" gains produced from the update of the 2014 business plan.

This comparison shows that the forecast gains, excluding non-technical power losses (i.e. reductions in costs related to metering, interventions and other gains) contained in the business plan presented by Enedis are higher than the gains expected in the 2014 business plan (+€38 million/year for 2024).

Table 8 : Linky gains excluding non-technical power losses*

In €million$_{nominal}$	2017	2018	2019	2020	2021	2022	2023	2024	Total
OPEX impact (adjusted 2014 BP)	-77	-104	-76	-21	66	126	143	153	**209**
OPEX impact (actual/Enedis's TURPE 6 proposal)	-66	-65	-43	-37	40	131	174	188	**323**
Difference	11	38	33	-13	-25	7	34	38	**114**

**A negative impact means an additional expense compared to the inertial scenario. On the contrary, a positive impact means savings on operating expenses compared to the inertial scenario resulting in a gain.*

The operating expenses gains (excluding non-technical power losses) brought by the Linky programme increase over the TURPE 6 period. At the end of the TURPE 6 period, i.e. in 2024, Linky will enable a drop in operation expenses of €231 million/year compared to 2019, i.e. a 5% gain in Enedis's operating expenses. These gains alone explain the fact that Enedis's operating expenses trajectory is on a downward trend during TURPE 6.

The overall objectives of the adjusted Linky business plan however are not reached once the non-technical power losses are included, while the gains related to the reduction of these losses were a very important item in the project (with an initial reduction goal of -3 TWh/year for 2021).

According to Enedis, this target remains relevant, but its attainment requires the deployment of all of the grid's management tools. Enedis believes it is able to reach this reduction goal of -3 TWh as from 2025 (mid-2020, the gain in non-technical losses totalled 1 TWh). CRE considers that the new reduction trajectory specified for Enedis is relevant and will ensure the attainment of this objective through the regulatory framework for expenses related to loss compensation (see section 2.3.1.2).

Table 9 : Linky non-technical gains*

In €million$_{nominal}$	2017	2018	2019	2020	2021	2022	2023	2024	Total
Non-technical losses impact (adjusted 2014 BP)	19	43	74	109	141	154	158	160	**859**
Non-technical losses impact (actual/Enedis's TURPE 6 proposal)	9	22	36	56	81	113	140	154	**609**
Difference	- 11	- 21	- 38	- 52	- 61	- 41	- 19	- 7	**- 249**

**A negative impact means an additional expense compared to the inertial scenario. On the contrary, a positive impact means savings on operating expenses compared to the inertial scenario resulting in a gain.*

The expenses gains related to non-technical losses will be gradual over the TURPE 6 HTA-BT period and should reach €118 million/year in 2024 compared to 2019 (3% of Enedis's operating expenses).

In sum, it is almost €1 billion in expenses that will be saved over the TURPE 6 HTA-BT period. CRE considers that the Linky gains should be in line with those of the business plan as at the end of the TURPE 6 HTA-BT period and therefore does not make any additional adjustments to Enedis's tariff proposal.

3.1.2.3.4 Summary of adjustments to Enedis's proposal

In summary, CRE's analysis leads to adopting a trajectory of net operating expenses (excluding purchases relating to the electricity system) for the TURPE 6 HTA-BT period of an average €4,535 million/year over the period (2019-2021 evolution of -1.3% and average annual evolution of -1.1% over the 2021-2024 period).

The trajectory of net OPEX excluding expenses related to the electricity system adopted over the TURPE 6 HTA-BT period is as follows:

Table 10 : Trajectories of net OPEX excluding expenses related to the electricity system (€million$_{nominal}$)

€million$_{nominal}$	*2019 Actual*	2021	2022	2023	2024	Average 2021-2024
Net OPEX (excluding expenses related to the electricity system) - proposed by Enedis	*4,673*	4,802	4,784	4,717	4,706	4,752

Adjustment adopted		- 189	- 214	- 220	- 247	218
Net OPEX (excluding expenses related to the electricity system – trajectory adopted)		4,613	4,571	4,497	4,459	4,535

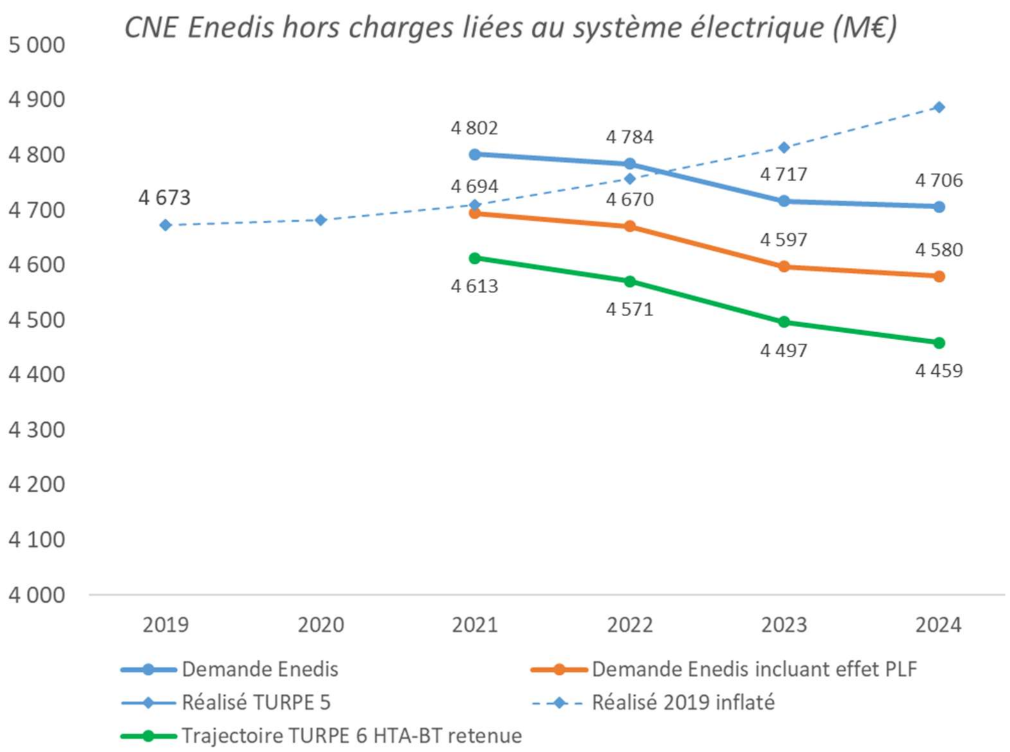

Figure 2 : Enedis's net OPEX excluding expenses related to the electricity system

3.1.2.4 Expenses related to the electricity system

3.1.2.4.1 Enedis's proposal

Enedis's proposal totals an average €4,885 million/year over the TURPE 6 HTA-BT period. It would lead to an increase in expenses related to the electricity system in 2021 of +€103 million, i.e. +2.2% compared to the actual amount for 2019. Expenses would then increase over the 2021-2024 period by an average +0.5% per year.

The forecast expenses related to the electricity system presented by Enedis in its tariff proposal for the TURPE 6 HTA-BT tariff period, are presented in the table below:

Table 11 : Expenses related to the electricity system proposed by Enedis for the TURPE 6 HTA-BT period

€million$_{nominal}$	*2019 Actual*	2021	2022	2023	2024
TURPE HTB (transmission grid access contract)	*3,616*	3,617	3,646	3,691	3,746
Power losses purchase cost	*1,096*	1,202	1,181	1,165	1,159
Connection to the transmission grid	*40*	36	42	33	23
Total *Evolution*	*4,752*	**4,855** *+ 2.2%*	**4,869** *+ 0.3%*	**4,889** *+0.4%*	**4,927** *+ 0.8%*

The main factors in Enedis's proposal are:

- the expenses related to power losses purchases, up in 2021 by +€106 million compared to the actual amount for 2019 (i.e. +9.7%), then down slightly during the TURPE 6 HTA-BT period (an average -1.2% per year over the 2021-2024 period), due to the combined effects of lower volumes supplied because of the effect of the COVID-19 health crisis and assumptions of higher electricity prices in 2021 and stable afterwards, mainly resulting from taking into account the expenses related to capacity certificates communicated by Enedis after the public consultation of October 2020, illustrated in the table below:

Table 12 : Assumptions relating to Enedis's loss purchase costs for the TURPE 6 HTA-BT period

Years	*Actual 2019 provisional*	2021	2022	2023	2024
Volume (TWh)	*24.7*	24.1	23.7	23.4	23.5
Amount (€million)	*1,096*	1,202	1,181	1,165	1,159
Unit price (€/MWh)	*44.3*	49.9	49.8	49.8	49.3

- the expenses related to access to the transmission grid, at a stable level in 2021 compared to the actual amount for 2019, then down by an average 1.2% per year between 2021 and 2024. This trajectory stems from the last electricity review supplied by Enedis after the public consultation of October 2020 and takes into account the forecast change in TURPE HTB during the 2021-2024 period specified by the deliberation of 17 December 2020[41].

3.1.2.4.2 CRE's analysis

The expenses related to the electricity system break down into three distinct items, all in the CRCP (partially for losses). CRE's analysis of these items is the following:

- with regard to the expenses for connection of new distribution substations to the transmission grid (an average €34 million/year), CRE considers that the assumptions adopted by Enedis are relevant;
- with regard to the expenses related to energy purchases for power losses compensation, CRE considers relevant the estimates of volumes supplied and energy costs proposed by Enedis, updated since the public consultation of October 2020 and which take into account the effects of the COVID-19 health crisis. With regard to volumes, the trajectory of power losses volumes results from the combined effects of the increase in technical losses due to the development of decentralised production and the drop in non-technical power losses made possible by the deployment of smart meters (see section 2.3.1.2);
- the assumptions of volumes withdrawn from the transmission grid taken into account by Enedis to estimate its transmission grid access contract bill (RTE "toll") are consistent with the last energy reviews conducted, which incorporate the effects of the COVID-19 health crisis.

CRE's analysis leads to adopting the trajectory of net operating expenses related to the electricity system proposed by Enedis for the TURPE 6 HTA-BT period, which total an average €4,885 million per year over the period (2019-2021 evolution of +2.2% and average annual evolution of +0.5% over the 2021-2024 period).

The trajectory of expenses related to the electricity system adopted over the TURPE 6 HTA-BT period is as follows:

Table 13 : Trajectories of Enedis's expenses related to the electricity system (€million$_{nominal}$)

€million$_{nominal}$	*2019 Actual*	2021	2022	2023	2024	Average 21-24
TURPE HTB (transmission grid access contract)	*3,616*	3,617	3,646	3,691	3,746	3,675
Power losses purchase cost	*1,096*	1,202	1,181	1,165	1,159	1,177
Connection to the transmission grid	*40*	36	42	33	23	34
Total *Evolution*	*4,752*	**4,855** *+ 2.2 %*	**4,869** *+ 0.3%*	**4,889** *+0.4%*	**4,927** *+ 0.8%*	**4,885**

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 HTA-BT.

[41] CRE deliberation no. 2020-314 of 17 December 2020

Table 14 : Enedis's total net operating expenses for the TURPE 6 HTA-BT period

€million nominal	*2019 Actual*	2021	2022	2023	2024	Average 2021-2024
Trajectory adopted by CRE (net OPEX excluding expenses related to the electricity system)	*4,673*	4,613	4,571	4,497	4,459	4 535
Trajectory adopted by CRE (expenses related to the electricity system)	*4,752*	4,855	4,869	4,889	4,927	4 885
Total net operating expenses	*9,424*	9,468	9,440	9,386	9,386	9 420

The trajectory of operating expenses adopted by CRE for TURPE 6 HTA-BT:

- gives Enedis:
    - an increase in operating expenses related to IS, to meet the growing needs of the network and users in terms of information systems (cybersecurity, energy transition, data, smart grid management, etc.), aimed nevertheless at controlling the efficiency of these expenses over the period;
    - tariff coverage of additional expenses to handle extra costs caused by climate events of an exceptional magnitude;
    - coverage of its staff expenses, by adopting Enedis's forecasts concerning its forecast staff trajectories and the attainment of profit-sharing objectives;
    - the means to carry out an ambitious R&D policy;
- allows customers to benefit from:
    - gains brought by the deployment of Linky meters;
    - the drop in production taxes decided within the framework of the 2021 draft finance law;
    - the productivity gains achieved by Enedis during TURPE 6 HTA-BT.

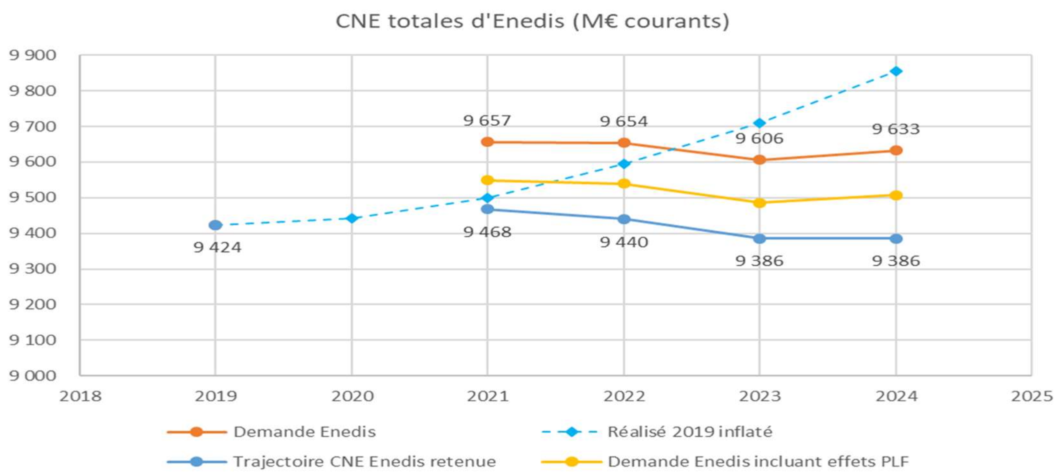

Figure 3 : Trajectory of Enedis's total net operating expenses over the TURPE 6 HTA-BT period

3.1.3 Calculation of normative capital expenses

3.1.3.1 Remuneration parameters

The principles for calculating Enedis's normative capital expenses (in particular the methodology for determining the different remuneration parameters) applied for TURPE 5 HTA-BT are re-adopted for the next tariff period (see section 2.1.1.2). However, CRE modifies the level of the remuneration parameters, in line particularly with the change in certain market parameters and corporate tax.

3.1.3.1.1 Enedis's proposal

Enedis proposes a margin on assets of 2.90% (nominal, before tax), up 16% compared to 2.50% in TURPE 5 bis, based on an asset beta of 0.40 compared to 0.34 in TURPE 5 bis, a remuneration rate for regulated equity of 2.40%, down compared to that in TURPE 5 bis (4.0%) and a remuneration rate for financial borrowings of 1.70%, down compared to that in TURPE 5 bis (3.0%).

3.1.3.1.2 CRE's analysis

CRE examined the different parameters used in the calculation of the margin on assets, the remuneration rate for regulated equity and the remuneration rate for financial borrowings. It commissioned a study by an external consultant to audit Enedis's remuneration proposal. This study was published within the framework of the public consultation of 8 October 2020[42].

On the occasion of this public consultation, CRE published a range for the envisaged margin on assets from 2.40% to 2.50% (nominal, before tax), a range for the remuneration rate envisaged for regulated equity from 2.10% to 2.50% (nominal, before tax) and a range for the remuneration rate envisaged for financial borrowings from 1.60% to 1.80% (nominal, before tax).

Among the contributors to the public consultation, many participants deem that the parameters envisaged by CRE are too high compared to the current market conditions and that the risk borne by Enedis is greatly overestimated. In particular, they stated that the remuneration level envisaged for Enedis would justify in return increasing the risks borne by Enedis, by strengthening the penalties for insufficient quality of service. Other contributors, including Enedis and its shareholder, consider on the contrary, that the parameters proposed by Enedis, particularly the beta, are legitimate given the remuneration conditions of European electricity system operators and the increase in the beta for French gas system operators, at the tariff revision in 2020.

In the present tariff decision, CRE adopts a margin on assets of 2.5%, a remuneration rate for regulated equity of 2.3% and a remuneration rate for financial borrowings (excluding Linky) of 1.7%.

Table 15 : Parameters for the calculation of Enedis's capital expenses

Parameters for the calculation of capital expenses	TURPE 5 bis	TURPE 6	
Risk-free rate (nominal)	2.70%	1.70%	A
Asset beta	0.34	0.36	B
Market risk premium	5.0%	5.2%	C
Tax rate	31.79%	26.47%	D
Tax deductibility for financial expenses	75%	100%	E
Margin on assets	2.5%	2.5%	(B×C)/(1-D)
Additional remuneration rate for regulated equity	4.0%	2.3%	A/(1-D)
Additional remuneration rate for financial borrowings (excluding Linky)	3.0%	1.7%	A x (1 - E x D) / (1 – D)

Compared to the values adopted in TURPE 5 HTA-BT, the main developments concern the following points:

- The risk-free rate adopted stands at 1.7%. It 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, 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 0.36, increased slightly compared to the level adopted for the previous period (0.34).

  CRE bases its decision concerning the asset beta on market observations of betas of comparable publicly traded electricity operators. This justifies a small increase. CRE also takes into account Enedis's regulatory

[42] Public consultation by the Energy Regulatory Commission no. 2020-017 of 8 October 2020 relating to the next tariff for the use of the public electricity distribution grids (TURPE 6 HTA-BT) (https://www.cre.fr/Documents/Consultations-publiques/prochain-tarif-d-utilisation-des-reseaux-publics-de-distribution-d-electricite-dit-turpe-6-hta-bt)

framework which continues to protect the level of Enedis's revenues from most risks. Moreover, given the specific remuneration of the Linky project, the beta adopted by CRE is comparable to that adopted on average in Europe.

- 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 Enedis over the 2021-2024 period.

Therefore, investments (excluding Linky) funded by Enedis's equity are remunerated at a rate of 4.8%. This remuneration applied during the TURPE 6 tariff period, both for investments made over this period and for those made during past tariff periods, once the funding is provided by Enedis's equity.

3.1.3.2 Investments

The investment trajectory specified by Enedis for the TURPE 6 period is marked by:

- a reduction in investments associated with the Linky project, whose end of deployment is scheduled for the end of the year 2021: the average annual expenses associated with Linky are estimated at €226 million per year over the TURPE 6 period compared to €742 million per year over the 2017-2019 period;
- an acceleration in investment expenses (excluding Linky), with average annual expenses of €3,629 million per year over this period, while they stood at an average €3,265 million per year (i.e. +11%) over the 2017-2019 period.

In total, Enedis presents a trajectory of lower investment expenses over the TURPE 6 period, with average annual expenses of €3,855 million per year, compared to an average €4,007 million per year during the TURPE 5 period (i.e. -4%).

Enedis plans for the following investment expenses over the next period:

Table 16 : Trajectories of Enedis's investment expenses over the TURPE 6 HTA-BT period

In €million nominal[43]	Actual 2019	2021	2022	2023	2024	Average annual TURPE 6	Annual average 2017-2019
Connection and reinforcement	1,623	1,593	1,584	1,643	1,800	1,655	1,499
Client connections	*977*	*951*	*976*	*1,020*	*1,105*	*1,013*	*897*
Producer connections	*277*	*333*	*334*	*360*	*423*	*362*	*248*
Metering and transformers	*111*	*99*	*79*	*68*	*68*	*78*	*97*
Grid reinforcement	*258*	*211*	*195*	*195*	*204*	*201*	*258*
Management of regulatory constraints	445	433	415	427	412	422	421
Infrastructure modification	*173*	*157*	*156*	*170*	*155*	*159*	*166*
Security, environment and regulatory obligations	*272*	*277*	*259*	*257*	*257*	*263*	*255*
Work tools and operating means	365	462	444	420	462	447	358
Operating means and logistics	*119*	*116*	*112*	*106*	*114*	*112*	*121*
Real estate	*52*	*92*	*69*	*74*	*78*	*78*	*54*
Information systems	*194*	*254*	*263*	*240*	*270*	*257*	*184*
Renewal, Quality and Modernisation	1,821	1,530	1,252	1,251	1,292	1,331	1,728
Serving quality	*999*	*1,053*	*1,074*	*1,119*	*1,176*	*1,105*	*986*
Linky	*822*	*477*	*179*	*132*	*116*	*226*	*742*
Total gross investments excluding Linky	3,432	3,541	3,516	3,609	3,850	3,629	3,265
Total gross investments	4,254	4,018	3,695	3,740	3,966	3,855	4,007

The evolution in investment expenses by category is specified in the graph below:

[43] With the following inflation assumptions: 0.20% in 2020, 0.60% in 2021, 1.00% in 2022, 1.20% in 2023 and 1.50% in 2024.

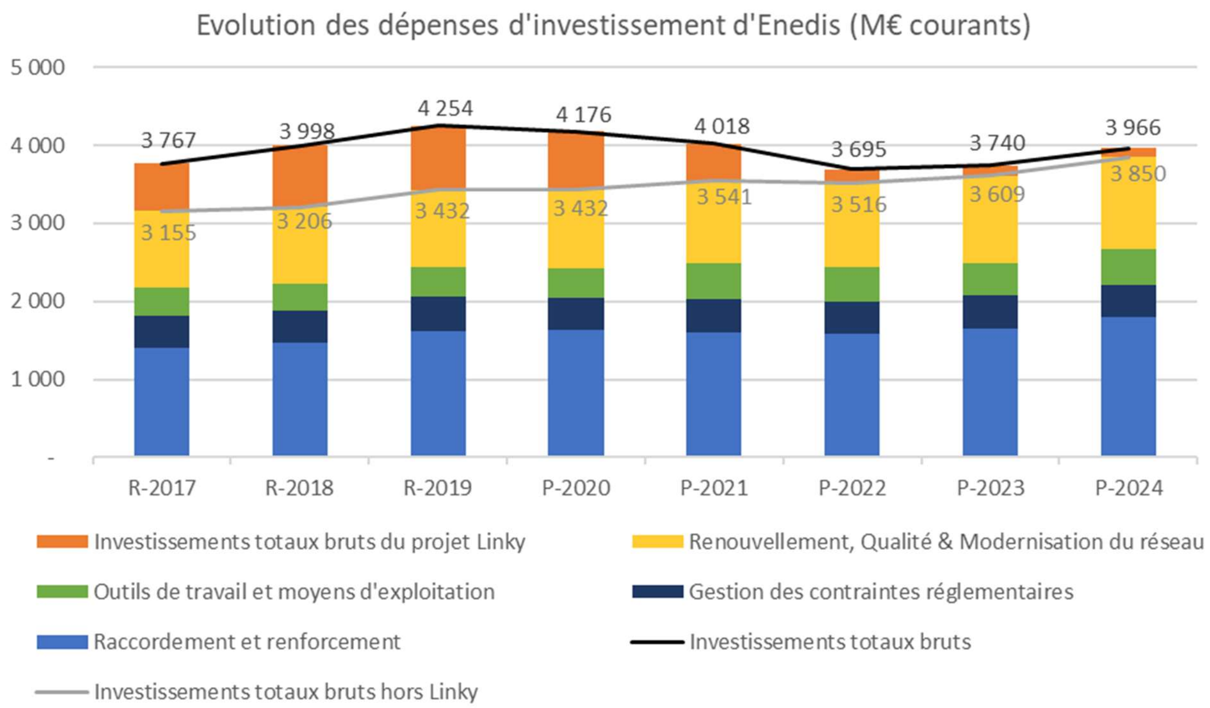

Figure 4 : Evolution in Enedis's investment expenses over the 2017-2024 period

With regard to investment expenses excluding Linky, the investment trajectory presented by Enedis, is based on three areas: (i) support the French multi-annual energy plan (PPE), (ii) maintain the good quality of supply and (iii) develop and modernise IS. In particular, Enedis projects:

- a major increase in investments related to connections and grid reinforcements (an average €1,655 million/year over the TURPE 6 period compared to €1,499 million/year over the TURPE 5 period, i.e. +10%): this increase is related mainly to an anticipated growth in demands for connections of EV charging infrastructure (in connection with the growth objectives for electric vehicles set by the multi-annual energy plan and new regulatory provisions concerning parking spaces in collective housing), and an increase in connections of decentralised renewable production installations (renewables connected annually in Enedis's network growing from 2,250 MW of installed power in 2019 to over 4,000 MW in 2014), to which is added a moderate growth in new buildings;
- stability in investments related to the management of regulatory constraints (an average €422 million/year over the TURPE 6 period compared to €421 million/year over the TURPE 5 period, i.e. +0%);
- a major increase in investments related to work tools and operating means (an average €447 million/year over the TURPE 6 period compared to €358 million/year over the TURPE 5 period, i.e. +25%): this increase is related particularly to the increase in IS and Telecom investment expenses (to respond, on the one hand, to the changes in the sector and in Enedis's activity, and on the other hand, to Enedis's determination to improve its performance in service of grid users), and to the electrification of Enedis's vehicle fleet and to three large projects in the real estate area (aimed respectively at bringing together its IS Division in two sites, creating an in-house training campus and reorganising its network of grid command centres);
- an increase in investments related to grid renewal and modernisation (an average €1,105 million/year over the TURPE 6 period compared to €986 million/year over TURPE 5, i.e. +12%): this increase is mainly related to an increase in infrastructure modernisation expenses, after a stabilisation over TURPE 5, because of the implementation of new methods for targeting the infrastructure most at risk, in order to improve the grid's resilience to weather hazards, and thus aim for a drop in outage time for 2030. In addition, Enedis's trajectory includes the renewal expenses after the sticky snow episode of 2019.

With regard to "grid" investments, CRE adopted, to prepare the forecast trajectories of the normative capital expenses of TURPE 6 HTA-BT, all of the investment forecasts in Enedis's proposal.

Concerning "non-grid" investments, the investment amounts presented by Enedis were reviewed within the framework of the audit of Enedis's net operating expenses. The adjustments finally adopted by CRE are presented in section 3.1.2.2.2. The investment trajectory adopted by CRE in the present decision takes these adjustments into account.

The overall investment trajectory adopted by CRE is presented in the table below:

Table 17 : Trajectory of Enedis's investment expenses adopted by CRE for the TURPE 6 HTA-BT period

In €million$_{nominal}$[44]	Actual 2019	2021	2022	2023	2024	Average annual TURPE 6	Annual average 2017-2019
Total gross investments excluding Linky	3,432	3,528	3,505	3,606	3,846	3,621	3,264
Total gross investments for the Linky project	822	477	179	132	116	226	742
Total gross investments	**4,254**	**4,006**	**3,684**	**3,738**	**3,962**	**3,847**	**4,006**

Lastly, the investment expenses included within the scope of the incentive regulation mechanism for "non-grid" capital expenses (see section 3.1.3.5) over the 2021-2024 period are as follows[45]:

Table 18 : Trajectory of Enedis's "non-grid" investment expenses adopted by CRE for the TURPE 6 HTA-BT period

In €million$_{nominal}$	2021	2022	2023	2024	Average annual TURPE 6
Information System investments	221	231	201	218	218
Real estate investments	79	57	71	74	70
Vehicle investments	35	35	33	42	36
Total "non-grid" investments	**335**	**323**	**305**	**333**	**324**

3.1.3.3 Assets under construction (AuC)

As stated in section 2.1.2.3, CRE introduces for the TURPE 6 tariff period, remuneration at the additional remuneration rate for financial borrowings (excluding Linky), of long-cycle AuC.

CRE requested Enedis to identify the volume of long-cycle investments which may be concerned by this mechanism. While Enedis maintains its request for a remuneration of all AuC, it submitted to CRE, after the public consultation of 8 October 2020, an estimate of its long-cycle AuC. Enedis considers that AuC associated with distribution substations and connection, renewal and structure works in the HTA grid, qualify as long-cycle AuC. Enedis estimates that the volume of AuC associated with these investments will represent, over the TURPE 6 period, roughly €860 million per year, which corresponds to the average AuC relating to distribution substations and engineering in the HTA network over the TURPE 5 period. The infrastructure identified by Enedis as long-cycle AuC represents more than half of the AuC accounted for over the TURPE 5 period.

[44] With the following inflation assumptions: 0.20% in 2020, 0.60% in 2021, 1.00% in 2022, 1.20% in 2023 and 1.50% in 2024.
[45] These amounts are included in the trajectories presented in section 2.1.3.2.

Table 19 : Trajectories of assets under construction identified by Enedis as long-cycle investments

In €million$_{nominal}$	Actual 2017	Actual 2018	Actual 2019	Annual average 2017-2019
Distribution substations	440	390	422	417
Engineering work in the HTA network	423	451	442	438
Sub-total assets under construction	**863**	**841**	**864**	**856**
Total assets under construction	**1,648**	**1,669**	**1,751**	**1,689**

On the basis of the information supplied by Enedis, CRE observes that the assets under construction relating to engineering work have a lifetime (period between the investment expense and commissioning) of 12 months. Moreover, Enedis's ambitions concerning the reduction in connection work times in particular, are aimed at reducing the duration of assets for this type of investment. On the contrary, the AuC relating to distribution substations have a lifetime of roughly 25 months. Therefore, CRE adopts only the distribution substations as long-cycle AuC.

It establishes the following forecast trajectory for AuC. The differences compared to this trajectory are covered in the CRCP:

Table 20 : Trajectories of the remuneration of assets under construction (in €million$_{nominal}$)

In €million$_{nominal}$	2021	2022	2023	2024	Annual average 2021-2024
Assets under construction	420	420	420	420	420

3.1.3.4 Integration of electrical risers in the RAB in accordance with the "Elan law"

3.1.3.4.1 Background

Article 176 of the ELAN law[46] specifies the integration in the public distribution network of all electric risers in operation by the end of a period of two years as from the 24 November 2018, unless explicitly refused by the owner or co-owners during this transitional period. In addition, all electrical risers put into service as from the publication of this law now belongs to the public electricity distribution network.

Up until the entry into effect of this law, part of the electrical risers in operation were already included in Enedis's inventory (designated "electrical risers under concession") and the rest, considered as belonging to the building owners (designated "electrical risers outside concession"). The ELAN law leads to a free transfer of electrical risers to Enedis.

The implementation of this legislative provision required preparatory work by Enedis on three points:

- the quantitative and qualitative identification of all electrical risers in operation based on an extrapolation of cadastres and client data, completed by a field analysis conducted on 10,000 electrical risers: until then, Enedis did not have an individualised inventory of risers (risers under concession were recorded as mass assets in Enedis's accounts). This inventorying identified 1,520,000 electrical risers in operation and their technical characteristics (number of delivery points and floors served, age or year of the riser, type of riser, etc.) without prejudice at this stage to their nature under or outside concession.
- the distinction between "under" and "outside of" concession[47]: using this inventory and its accounting base, Enedis estimated the volume of risers under concession, by year of commissioning, based on a reconstitution of historical investment costs and a set of conventions and assumptions. For example, electrical risers commissioned after the signing of the 1992 concession agreement (following the concession specifications model of this year - CDC92) were all considered as being under concession and all those dated before 1966, as outside of concession (because Enedis does not have an inventory enabling it to have a clear vision of electrical risers under concession before this date);
- by the difference with the total inventory, Enedis deduced the number of risers "outside the concession";

[46] Law no. 2018-1021 of 23 November 2018 on changes in housing, land management and digital technology
[47] The distinction between risers "under" and "outside" concession for the city of Paris was not finalised at the date of performance of the audit in July 2020.

- the determination of a unit value for risers “outside the concession”: not having a market value for electrical risers, the valuation method applied by Enedis is based on the accounting standard IFRS 13[48]. Enedis therefore adopted a “replacement value”, i.e. the value of a new riser to which is applied an obsolescence and wear coefficient. Therefore, the unit value of risers “outside the concession” is different to that of risers “under concession”, which are valued at the historical cost (for equivalent characteristics).

In parallel, Enedis reflected on the lifetime of risers. On this basis, Enedis adopted a lengthening from 40 to 60 years of the depreciation period for electrical risers, based on the results of technical tests conducted in laboratories and field observations concerning the incident rate for electrical risers.

The first electrical risers were included in 2019 in Enedis’s accounts and the lengthening of the depreciation period for all risers (historically or newly under concession) is effective in Enedis’s accounts since 1 January 2020. The complete integration of all of the 768,000 electrical risers estimated by Enedis outside of concession (termed "Elan” risers) is scheduled for the end of 2020. Enedis estimates the net book value of these risers at €497 million, which will increase Enedis’s RAB, but not the regulated equity.

In accordance with the margin on assets (fixed at 2.5% for the present tariff period), the tariff impact of this integration totals +€32 million/year:

- +€12 million/year, for the remuneration of these assets, with a downward trend related to asset depreciation;
- +€20 million/year for depreciation provisions.

It should be noted moreover, that the lengthening of the lifetime of risers under concession has several consequences for Enedis and for the tariff:

- an increase in the entry value of the new electrical risers in the RAB, with a greater number of risers being considered as not depreciated. If the lifetime of electrical risers had not been lengthened, the net book value to be integrated in the RAB would have been €200 million, and not €497 million;
- a provision write-back for renewals for an amount of €60 million for the year 2019, reducing the level of normative capital expenses by that amount for that year, as well as a drop in depreciation provisions which Enedis estimates at almost €30 million/year as from 2020.

3.1.3.4.2 Purpose of CRE’s audit

Given the complexity of this matter and the financial amounts at stake, CRE commissioned an external consultant to perform an audit, in June and July 2020, to conduct

- an analysis of the method used by Enedis to identify the electrical risers “under” and “outside” the concession and an analysis of the results of the inventory, supported by an evaluation of two representative concessions;
- an analysis and accounting evaluation covering the determination of the unit value of risers “outside the concession” and an assessment of the doctrine used to justify the change in lifetime.
- an impact assessment concerning Enedis’s capital expenses (remuneration and depreciation).

The report associated with this audit was published within the framework of the public consultation of 8 October 2020 and of the present deliberation.

With regard to the inventory and identification method for the number of risers “under” and “outside” the concession, the conclusions of the audit are as follows:

- the overall identification of the 1,520,000 risers in operation, based on an algorithmic method completed by a field analysis of 10,000 columns , is considered relevant by the auditor, who concludes that the overall count is reasonably representative of the reality;
- however, regarding the distinction between risers “under” and “outside” the concession, the auditor considers that certain assumptions adopted by Enedis are not justified and tend to increase the number of risers “outside the concession” (+27% according to the auditor).

[48] IFRS 13: the fair value is the price that would be received for the sale of an asset or paid for the transfer of a liability in an orderly transaction in the main market (or the most favourable) at the evaluation date based on current market conditions (i.e. an exit price), whether this price is directly observable or estimated using another evaluation technique. In the absence of a market, the value may be determined according to the income approach or the cost approach.

- The consultant highlights, for example, that although accounting documents do not date back to before 1966, it should have been considered that some risers were under concession before that time. Not adopting this assumption leads to maximising the number of risers "outside the concession" and causes a major discontinuity in the counting of risers "under" concession, which is not realistic or justifiable according to the auditor.
- In addition, the auditor highlights that:
    - to consider that risers prior to 1958 were renovated only as from 1966 leads to decreasing the age of the risers and therefore increasing the net book value to be integrated for risers "outside" the concession;
    - 4,000 risers post 1992 specifications are considered "outside the concession".

With regard to the individual valuation of risers "outside the concession", the auditor considers that it is not justified for Enedis to receive remuneration based on an average unit value of risers "outside the concession" different to that of risers "under concession". The auditor states that for the determination of remuneration, a relevant estimation method would have been to observe the risers already under concession and apply the same valuation method for all risers.

Lastly, with regard to the lengthening of the lifetime from 40 to 60 years, the auditor does not challenge the technical studies conducted by Enedis on riser samples to justify this lengthening. It states nevertheless, that without quantified and structured feedback on the state of the infrastructure, it would have been reasonable to define an observation period before lengthening the lifetime.

3.1.3.4.3 CRE's analysis

The inventorying and identification of electrical risers conducted by Enedis is the result of extensive and complex work performed over several years. CRE notes that given the data available and for the purpose of simplifying this complex process, it was necessary for Enedis to use a certain number of decisive assumptions.

CRE agrees, as it stated in the public consultation of October 2020, with most of the auditor's conclusions. It considers that certain conventions adopted by Enedis tend, unjustifiably, to increase the total value of risers "outside the concession" which will be included by the end of 2020 in Enedis's RAB.

Method for inventorying and identifying risers

With regard to the method for inventorying and identifying risers, CRE considers that most of the auditor's recommendations are relevant, except for the one relating to the risers post CDC92 (see below) concerning in particular the presence of risers under concession as of 1958 and the assumption of the renovation of risers during the period from 1958 to 1992.

CRE had specified that if Enedis did not rectify its inventory accordingly before the accounting integration at the end of November 2020 of risers "outside the concession", it would revise the company's accounts to determine the amount of the capital expenses associated with these risers having to be covered by the tariff.

Valuation of risers "outside the concession"

With regard to the valuation of risers "outside the concession", CRE shares the conclusions of the auditor and considers that the assumptions adopted by Enedis would lead to an unjustified increase in the capital expenses related to the integration of electrical risers. CRE considers that the average unit costs of an efficient grid operator, which are the only ones it must cover in the tariffs, cannot differ for risers under concession and outside the concession, whose technical characteristics are the same.

Enedis having already integrated certain risers "outside the concession" in its balance sheet, CRE stated in the consultation that it intended to perform a restatement to calculate the normative CAPEX associated with risers: each year as from 2021, CRE would adopt a valuation of risers "outside the concession" in line with the values of risers "under the concession". This adjustment would apply, in the interest of consistency, to the associated depreciation provisions.

Depreciation period for electrical risers

Lastly, with regard to the modification of the depreciation period for risers, CRE stated in its public consultation that it noted Enedis's decision which is based on an analysis of the technical possibilities of these assets, and therefore intended to take into account this modification to calculate Enedis's capital expenses.

Half of the participants that expressed their opinion on these adjustments are in favour of CRE's proposals. Some of these participants consider, moreover that CRE should have gone further and question the opportunistic nature of lengthening the lifetime and its impact on the trajectories for the renewal of electrical risers. Enedis however, along with several other participants, consider that the adjustments concerning the inventory are not justified and are a matter for debate among experts. In addition, these participants highlight that the costs borne by Enedis must be covered by the tariff and therefore challenge the legitimacy of the adjustment to the depreciation provisions.

Following this feedback, CRE decides to maintain its adjustment proposals both for the inventory and for the valuation of electrical risers. It maintains its observation that some of the conventions adopted by Enedis tend, unjustifiably, to increase the total value of risers "outside the concession" and that this strategy generates additional costs that do not correspond to those of an efficient system operator and therefore must not be covered by the tariffs.

If Enedis does not make an adjustment to the entry value of electrical risers resulting in an overall value identical to that adopted in the present deliberation, CRE will make the necessary restatements. For this purpose, the present deliberation defines adjustment trajectories, presented in annex 9, for the RAB, regulated equity and depreciation provisions. These adjustments are calculated based on, on the one hand, the inventory of electrical risers and the valuation elements provided by Enedis, and on the other hand, the adjustments proposed by the auditor and adopted by CRE.

3.1.3.5 Normative capital expenses

<u>Trajectory of normative capital expenses</u>

The table below presents the forecast trajectories of the RAB excluding Linky, the Linky RAB and Enedis's regulated equity from 2021 to 2024 (TURPE 2 regulated equity included).

Table 21 : Forecast trajectory of the RAB excluding Linky, the Linky RAB and Enedis's regulated equity

In €million$_{nominal}$	2019 actual	2021	2022	2023	2024	Average 2021-2024
RAB excluding Linky (as at 01.01.N)	51,043	53,982	55,130	56,362	57,608	55,770
Linky RAB (as at 01.01.N)	1,652	2,803	3,027	2,778	2,540	2,787
Regulated equity (as at 01.01.N)	7,637	8,893	9,431	10,063	10,708	9,774

The table below breaks down the forecast trajectory of Enedis's normative capital expenses from 2021-2024:

Table 22 : Forecast trajectory of Enedis's normative capital expenses

In €million nominal	2019 actual	2021	2022	2023	2024	Average 2021-2024
Normative capital expenses excluding Linky[49] (1)	4,108	4,170	4,282	4,450	4,575	4,369
of which application of the margin on assets	*1,276*	*1,350*	*1,378*	*1,409*	*1,440*	*1,394*
of which remuneration of regulated equity	*305*	*205*	*217*	*231*	*246*	*225*
of which depreciation provisions excluding Linky	*2,529*	*2,649*	*2,731*	*2,855*	*2,936*	*2,793*
of which provisions for renewals	*-2*	*-33*	*-44*	*-46*	*-47*	*-42*
Linky normative capital expenses (2)	333	540	559	523	487	527
of which remuneration of the Linky RAB	*169*	*287*	*310*	*285*	*260*	*286*
of which depreciation of the Linky RAB	*163*	*253*	*249*	*238*	*227*	*242*
Remuneration of AuC (3)	0	7	7	7	7	7
Total restatement for integration of ELAN law electrical risers in the RAB (4)	0	-12	-11	-11	-10	-11
Total capital expenses (1)+(2)+(3)+(4)	4,441	4,706	4,837	4,969	5,060	4,893

<u>Trajectory of "non-grid" normative capital expenses</u>

The table below breaks down the specific trajectory of the RAB and normative capital expenses for Enedis's "non-grid" assets from 2021 to 2024, which are subject to a specific regulation (defined in section 2.3.2.2 of the present deliberation):

[49] These trajectories include the capital expenses relating to the assets concerned by the incentive regulation mechanism for "non-network" capital expenses.

Table 23 : Forecast trajectory of the “non-grid” RAB

In €million nominal	2019	2021	2022	2023	2024	Average 2021-2024
Information systems RAB (as at 01.01.N)[50]	161	534	551	558	503	536
Real estate RAB (as at 01.01.N)	221	233	267	277	299	269
Vehicle RAB (as at 01.01.N)	55	60	69	77	82	72
Total “non-grid” RAB	**437**	**827**	**888**	**912**	**884**	**878**

The assets concerned by this mechanism not having any concession liability counterpart, they are remunerated as regulated equity. Therefore, the forecast amounts for "non-grid" capital expenses[51] are as follows:

Table 24 : Forecast trajectory of incentive-backed capital expenses

In €million nominal	2021	2022	2023	2024	Average 2021-2024
Information system capital expenses	230	251	283	263	257
Information systems remuneration	26	26	27	24	26
Information systems depreciation	204	225	256	239	231
Real estate capital expenses	56	60	62	66	61
Real estate remuneration	11	13	13	14	13
Real estate depreciation	45	47	49	51	48
Vehicle capital expenses	28	30	32	36	32
Vehicle remuneration	3	3	4	4	3
Vehicle depreciation	26	27	28	32	28
Incentive-backed capital expenses	**314**	**341**	**377**	**364**	**349**

Since Enedis has an incentive to control its capital expenses, the differences between forecast trajectories and actual trajectories will not be taken into account in the CRCP over the TURPE 6 period.

3.1.4 CRCP as at 1 January 2021

The total estimated amount of Enedis’s CRCP balance under TURPE 5 HTA-BT to be taken into account in the calculation of the allowed revenue is +€588 million in favour of Enedis, therefore being added to the allowed revenue of TURPE 6. This balance is due mainly to:

[50] In 2019, only the RAB within the scope of incentives (according to the TURPE 5 definition) is reflected in this table, while for the years 2021 to 2024, all IS (excluding Linky) commissioned as at 31 December 2020 within and outside the scope of incentives are included. For assets with commissioning forecast after 31 December 2020, only the forecast expenses within the scope of incentives (based on the TURPE 6 definition) are presented afterwards.
[51] These amounts are included in the trajectories presented in section 2.1.3.3.

- tariff revenues lower than forecast at €486 million; this difference is due mostly to the impact of the health crisis on electricity consumption in 2020 (effect estimated at -9.3 TWh in volumes supplied by Enedis, including -6.5 TWh for the first half of 2020);
- expenses related to loss purchase +€226 million higher than forecasts, due to a higher electricity cost in 2020 (€44/MWH) compared to the forecasts used for 2020 during the preparation of TURPE 5 HTA-BT (€39/MWh);
- contributions to the electricity equalisation +€164 million higher than forecasts. This difference is due to:
    - an expense of +€80 million related to the application of the flat-rate method over the period 2012-2017[52];
    - an expense related to the flat-rate method for the year 2020 evaluated at +€28 million;
    - electricity equalisation fund contributions for EDF SEI, EDM, Gérédis and EEWF in 2020 evaluated at +€227 million, i.e. a difference of +€59 million compared to the forecast value adopted during the preparation of TURPE 5 HTA-BT;
- expenses for public transmission grid access in 2020 lower by -€170 million compared to the forecast, because of the drop in withdrawals by Enedis in RTE's grid;
- capital expenses lower by -€132 million compared to forecasts. This difference is due mainly to a Linky programme cost less than estimated, leading to a lower remuneration base and depreciation than estimated. A possible delay in the execution of its 2020 investment programme has not been estimated by Enedis at this stage;
- an overall penalty of -€28 million associated with incentive regulation for losses.

Table 25 : Forecast CRCP balance as at 1 January 2021

	Montant (M€$_{2020}$)	
CRCP balance as at 1 January 2020	285	
Forecast differences for items included in the CRCP	287	
of which difference anticipated for tariff revenues		*358*
of which difference anticipated for loss purchase expenses		*226*
of which difference anticipated for FPE contributions		*164*
of which difference anticipated for public transmission grid access expenses		*-170*
of which difference anticipated for normative capital expenses		*-132*
of which penalties anticipated		*-28*
Discounting at the risk-free rate of 2.70%	15	
Forecast CRCP balance as at 1 January 2021	**588**	

CRE re-adopts the CRCP reconciliation method used for TURPE 5 HTA-BT. The CRCP balance for TURPE 5 HTA-BT, as at 1 January 2021, will therefore be reimbursed through equal instalments over the four-year period of TURPE 6 HTA-BT, i.e. €153 million/year to be added to the expenses to be covered.

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

3.1.5 Allowed revenue for the 2021-2024 tariff period

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

[52] In accordance with the orders of 13 June 2019 concerning the coefficients to be applied to the formula for electricity equalisation for the years 2012 to 2017

- net operating expenses (see section 3.1.2);
- capital expenses (see section 3.1.3);
- reconciliation of the CRCP balance calculated as at 1 January 2021 (see section 3.1.4);
- reconciliation of the Linky smoothing regulatory account, in compliance with the provisions of the deliberation of 2014 relating to the incentive regulation for the Linky project.

It breaks down as follows:

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

In €million$_{nominal}$	*Actual 2019*	2021	2022	2023	2024	Average 2021-2024
Expenses related to the electricity system	*4,752*	4,855	4,869	4,889	4,927	4,885
Net operating expenses excluding purchases related to the electricity system	*4,673*	4,613	4,571	4,497	4,459	4,535
Normative capital expenses	*4,442*	4,706	4,837	4,969	5,060	4,893
CRCP reconciliation	*- 21*	153	153	153	153	153
CRL reconciliation	*- 304*	-228	-7	165	291	55
Allowed revenue	***13,541***	**14,099**	**14,424**	**14,673**	**14,890**	**14,522**

The average level of Enedis's expenses to be covered for the TURPE 6 HTA-BT period (net OPEX + normative CAPEX) will total an average €14,313 million per year. Over the 2019-2024 period, it will be updated by an average +0.6% per year, as a result of a drop in operating expenses by an average -0.1% per year and an increase in normative CAPEX by an average +2.6% per year.

Enedis's allowed revenue (expenses to be covered to which is added CRCP reconciliation and CRL reconciliation) is updated by +4.12% between 2019 and 2021, and then by an average +1.8% per year over the TURPE 6 period.

3.2 Assumptions concerning changes in the number of clients, subscribed power and volumes supplied

3.2.1 Changes recorded in the period covered by TURPE 5 HTA-BT

TURPE 5 projected over the 2017-2020 period an average increase in the number of customers by +0.8% per year and an average increase in the volume supplied by +0.5% per year excluding climate effects.

Over the 2017-2019 period, the number of clients connected to Enedis's network grew slightly faster than projected. However, the volumes supplied by Enedis (i.e. withdrawn from its network) were lower by an average 3 TWh per year compared to the forecast trajectory of TURPE 5 HTA-BT (i.e. roughly -1%). With an adjustment for climate variations, the difference is even an average 5 TWh. According to Enedis, it is mostly the result of a greater drop in household consumption than expected.

Moreover, consumption in the year 2020 are well below forecasts, due mainly to the COVID-19 crisis.

<table>
<caption>Table 27 : Number of customers and volumes supplied over the TURPE 5 HTA-BT period</caption>
<tr><th colspan="2"></th><th colspan="2">2017</th><th colspan="2">2018</th><th colspan="2">2019</th><th colspan="2">2020</th></tr>
<tr><th colspan="2"></th><th>Proj. TURPE 5</th><th>Actual</th><th>Proj. TURPE 5</th><th>Actual</th><th>Proj. TURPE 5</th><th>Actual</th><th>Proj. TURPE 5</th><th>Estimated *</th></tr>
<tr><td colspan="2">Number of customers (thousands)</td><td>36,196</td><td>36,259</td><td>36,487</td><td>36,565</td><td>36,780</td><td>36,951</td><td>37,076</td><td>37,193</td></tr>
<tr><td rowspan="2">Volume supplied (TWh)</td><td>Under actual weather condition s</td><td rowspan="2">353</td><td>352</td><td rowspan="2">353</td><td>351</td><td rowspan="2">354</td><td>347</td><td rowspan="2">356</td><td rowspan="2">333</td></tr>
<tr><td>excluding climate effects*</td><td>348</td><td>349</td><td>348</td></tr>
</table>

**includes the effect of the health crisis*

3.2.2 Enedis's proposal

Withdrawals

To project the actual volumes over the TURPE 6 period, Enedis analysed the underlying elements (climate, structural growth rate, other effects) of the evolution of actual volumes over the 2017-2019 period.

To determine the recent structural growth rate, Enedis adjusts the actual volumes over the 2017-2019 period for climate and calendar effects (leap years and number of weekends) and shedding effects. Enedis estimates a structural growth rate close to 0% over the 2017-2019 period. This rate is the result of two effects which offset each other:

- the increase in the number of sites, which stands at +0.9% per year (between 320,000 and 350,000 additional sites per year);
- the drop in individual consumption related to actions to control energy demand and less installations of electric heating in new homes, which stands at -1% per year.

Enedis anticipates stability in these developments for the TURPE 6 period: Enedis considers in particular that the impact of the development of new uses (deployment of electric vehicles for example) should be offset by the deployment of self-consumption and the intensification of energy efficiency actions. In its tariff proposal, Enedis therefore projects stable volumes withdrawn excluding climate effects and a slight increase in the number of customers.

In addition, Enedis updated its tariff proposal with a quantitative analysis of the COVID-19 effect on volumes supplied by Enedis for the TURPE 6 period. Enedis anticipates a return to normal in 2024, after a decline in in volumes supplied by 7 TWh in 2021, 4 TWh in 2022 and 1 TWh in 2023 compared to its initial proposal.

Table 28 : Trajectories of the volume supplied and the number of customers in Enedis's tariff proposal

	2021	2022	2023	2024
Volume supplied excluding COVID-19 effects (TWh)	347.8	347.8	347.8	349.2*
Volume supplied post COVID-19 effects (TWh)	340.7	343.5	346.4	349.2
Number of customers connected (in thousands)	37,527	37,864	38,205	38,548

**The increase in the volume supplied in 2024 is due to the fact that it is a leap year (effect estimated by Enedis at +1.2 TWh).*

The sum of subscribed power is estimated by Enedis by client segment over the 2021-2024 period, by projecting over this period the change observed between the years 2019 and 2020:

- stability for HTA clients (distribution grid access contract and C2/C3);
- steady increase by +1.3% per year for BT >36 kVA (C4) clients;
- steady increase by +0.9% per year for BT ≤ 36 kVA (C5) clients.

The evolution in subscribed power is, according to Enedis, driven by the respective dynamics of the clients in each segment; Enedis has not identified any trend in the evolution of subscribed power according to the user.

Injections

The average level of injections from the transmission grid projected by Enedis over the TURPE 6 period is lower by roughly 12 TWh (-4%) compared to 2019. This volume effect drives down RTE's toll level. It is due, at the start of the period, to a major drop in consumption because of COVID-19, and at the end of the period to the increase in decentralised production (+3.6 TWh, i.e. +7% per year over the 2021-2024 period), which offsets the pick-up in consumption.

3.2.3 CRE's analysis

CRE analysed the trajectories of the number of clients, subscribed power and volumes supplied presented by Enedis.

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, the operators worked jointly to present consistent trajectories.

CRE considers that Enedis's forecasts are consistent, both with the last values recorded and with the changes in progress in the electricity system and new uses, taking into account the different effects, upward and downward, of the deployment of Linky, efforts to control energy demand, EV deployment and self-consumption. Moreover, these assumptions take into account the impacts of the COVID-19 crisis on electricity consumption and therefore on withdrawals in the distribution network, which extend up to the year 2023, a point raised by contributors to the public consultation.

CRE therefore adopts Enedis's assumptions concerning the number of clients served, the sum of subscribed power and the volumes supplied by client segment, on which Enedis's forecast expense and revenue trajectories depend.

3.3 Trajectory of the tariffs for the use of the public electricity distribution grids

TURPE 5 HTA-BT was characterised by an initial increase in the tariff level by +2.7%, which was then updated based on inflation. With regard to TURPE 6 HTA-BT, 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 precarious grid users or users with atypical consumption profiles. Therefore, the evolution in tariff coefficients will be smoothed during the TURPE 6 period based on the trajectory of expenses to be covered and forecast subscriptions for the tariff period.

The tariff applicable as at 1 August 2021 is defined in section 5.2.1 of the present deliberation. They correspond to an average increase by +0.91% as at 1 August 2021 compared to the current tariffs and an average +1.39% 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 HTA-BT tariffs to the assumptions of the number of clients, subscribed power and volumes supplied 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 HTA-BT period, the forecast allowed revenue and forecast revenues are as follows:

Table 29 : Enedis's forecast allowed revenue and forecast tariff revenues for the TURPE 6 HTA-BT period

In €million$_{nominal}$	2021	2022	2023	2024	Net present value
Forecast allowed revenue	14,099	14,424	14,673	14,890	56,624
Forecast tariff revenues (excluding reconciliation of the CRCP balance)	14,058	14,236	14,707	15,094	56,624
Annual differences between projected revenues and projected allowed revenue	*- 41*	*- 188*	*34*	*204*	*0.0*

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

Table 30 : Forecast inflation and update factor X of TURPE 6 HTA-BT

	2021	2022	2023	2024
Forecast inflation between year *N-1* and year *N*	0.60%	1.00%	1.20%	1.50%
Update factor X	0.31%	0. 31%	0.31%	0,.31%
Forecast evolution as at 1 August of year *N* (excluding reconciliation of the CRCP balance)	0.91%	1.31%	1.51%	1.81%

4. STRUCTURE OF THE TARIFF FOR THE USE OF THE PUBLIC ELECTRICITY DISTRIBUTION 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 reinforced 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 level 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 in 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 grid use is high can generate congestion and cause, in the long term, costly grid reinforcement needs.

The electricity distribution grids are scaled mainly to enable energy transit 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. Ass illustrated in the following figure, these periods occur mainly in winter.

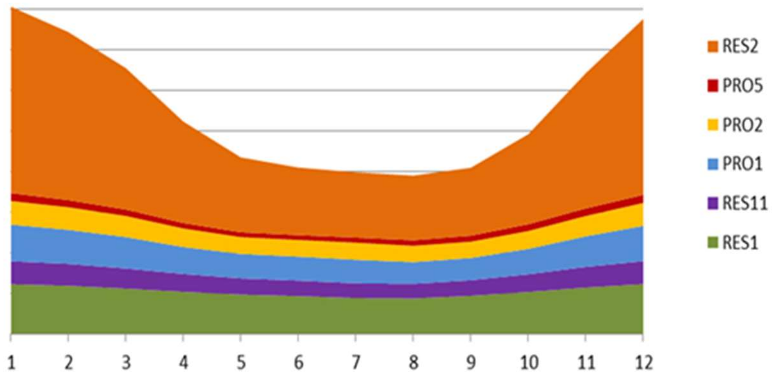

Figure 5 : Distribution, in base 100, of French electricity consumption of delivery points connected in BT <36 kVA) by month and by segment (source: Enedis)

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 generalisation 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 on 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.

The detailed analysis of bill increases related to the tariff structure developments adopted is presented in annex 10.

In addition, the structure development will have diluted and gradual effects on the electricity bills of the smallest consumers, since, for customers having subscribed to an integrated supply offer, the tariff signals related to the grids are not necessarily fully transmitted in the price billed. The price billed to these customers is composed of supply, mandatory withdrawals and an amount covering transmission, frequently corresponding to the average of the TURPE options envisaged for the category of clients subscribing to the offer.[53].

Similarly, the regulated sales tariffs (TRV), built by accumulation of all components, include for each TRV option an “optimised average TURPE” element, reflecting only the tariff signals on average sent by the TURPE tariff option subscribed by each consumer.

4.2 Conservation of the general structure of TURPE 5 HTA-BT

4.2.1 Tariff components

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

- management and metering costs are costs are costs that do not depend on the use of the grid as such, but on the type of service enabling access to and use of this grid, provided by the system operators based on voltage levels and user categories concerned (costs of customer management, telephone assistance, billing and collection, maintenance of metering devices, 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.

[53] For illustrative purposes, in BT≤ 36 kVA, the Linky meter offers two timetables: the “DSO timetable” divides the TURPE billing period into 4 time categories, while the “supplier timetable” enables suppliers to bill their clients in 10 distinct time categories.

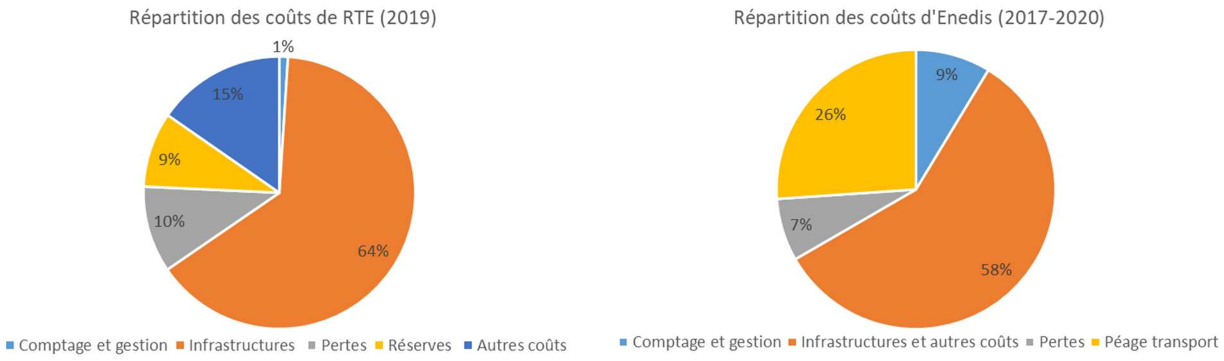

Figure 6 : Illustrative distribution of the annual expenses borne by RTE and Enedis (source: RTE and Enedis data, CRE analysis)

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 levels 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 level, 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 levels 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 to the cost of power losses compensation billed to RTE under the InterTSO compensation cross-border 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 among the pricing principles. Contributors were largely in favour. CRE therefore decides to adopt this proposal for the TURPE 6 period.

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. CRE adopts the principle of a generalisation of options with four time categories for the TURPE 6 period, based on the timetable described in section 4.4.1

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

Table 31 : Form of tariffs by voltage level

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 HTA-BT

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 covers the costs of customer management, physical and telephone reception of users, billing and collection. The amount of this component depends on the contract conditions between the DSO and the user: the user may sign a contract for access to the distribution network (CARD) directly with the DSO, or sign a contract with its supplier including grid access (this is a “single contract” also involving the DSO, in a tripartite contract agreement, which concerns the great majority of clients connected to the distribution network).

As indicated in its public consultations of May and October 2020, CRE performed a thorough analysis of Enedis’s management costs during work relating to remuneration of suppliers for the management of clients with a single contract, which led to a change in the management component level, established in the deliberation of 26 October 2017[54] and adopted in the TURPE 5 bis HTA-BT.

CRE considers that these costs have not changed significantly since the deliberation of 26 October 2017.

Therefore, the amount of the management component does not change in TURPE 6 HTA-BT. The specific case of the management component applicable to individual self-consumers or to participants in collective self-consumption operations is addressed in section 4.5.1.

The amount of the management component, excluding the R_f and C_{Card} coefficients, applicable as at 1 August 2021, is presented in detail in section 5.2.1.1.

4.3.2 Metering component

Metering costs cover the costs of supplying, installing and maintaining metering systems, the costs of control, metering and transmission of billing data and costs related to the flow reconstitution process.

The deployment of smart meters (Linky, PME/PMI and Saphir) as well as IS meter interfacing influence these metering costs, with Linky meters enabling major savings on metering costs.

CRE therefore proposed, in its public consultations of May 2019 and October 2020, reducing the metering component in the BT≤36 kVA and in HTA categories, in order to take into account this drop in costs. Participants were in favour of such a development. Some participants however considered that the drops appeared too little, particularly

[54] CRE deliberation no. 2017-239 of 26 October 2017 amending CRE’s deliberation of 17 November 2016 deciding on the tariffs for the use of the public electricity grids in the HTA and BT voltage levels (medium voltage and low voltage) https://www.cre.fr/Documents/Deliberations/Modification/turpe-hta-et-bt

in the BT≤36 kVA voltage level. This limited drop in metering costs is due in particular to the substantial IS developments necessary for the deployment of new communication channels, particularly in the mass market, which partly offsets the drop in metering costs associated with the deployment of smart meters.

Moreover, CRE fine-tuned its analysis of metering costs since the public consultation of October 2020 and in particular updated the parameters adopted for Enedis's capital costs. This adjustment leads, compared to the public consultation of October, of an additional drop in the metering components in the HTA and BT>36 kVA voltage levels.

CRE fixes, for the TURPE 6 period, the following new metering components:

- in HTA, the metering component applicable as at 1 August 2021 is €309/year (compared to €565/year currently, i.e. a drop by roughly -45%);
- in BT > 36 kVA, the metering component applicable as at 1 August 2021 is €232/year (compared to €438/year currently, i.e. a drop by roughly -47%);
- in BT ≤ 36 kVA, the metering component applicable as at 1 August 2021 is €18.02/year (compared to €20.88/year currently, i.e. a drop by roughly -14%).

In addition, TURPE 5 HTA-BT specified a different metering component based on whether the owner of the metering mechanism is the user or the system operator or the authority organising energy distribution. Enedis stated to CRE:

- that no mass market client (C5 segment) was the owner of their metering mechanism;
- that only 25 active metering mechanisms among the 520,000 business market metering mechanisms (C1-C4 and P1-P3) segment) are the property of their users.

Given the volumes concerned and since all metering devices must in principle, be part of infrastructure under concession, CRE simplifies the metering component and TURPE 6 HTA-BT therefore does not specify any specific metering component for users that are owners of their metering device.

The detailed amounts of the metering component are specified in section 5.2.1.2.

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 4.3.3.3).

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 compensating power losses and balancing reserves based on energy transit between voltage levels.

The new method, described in detail in annex 11, 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 loads, 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 level, then taking into account the ancillary costs (power losses compensation, 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:

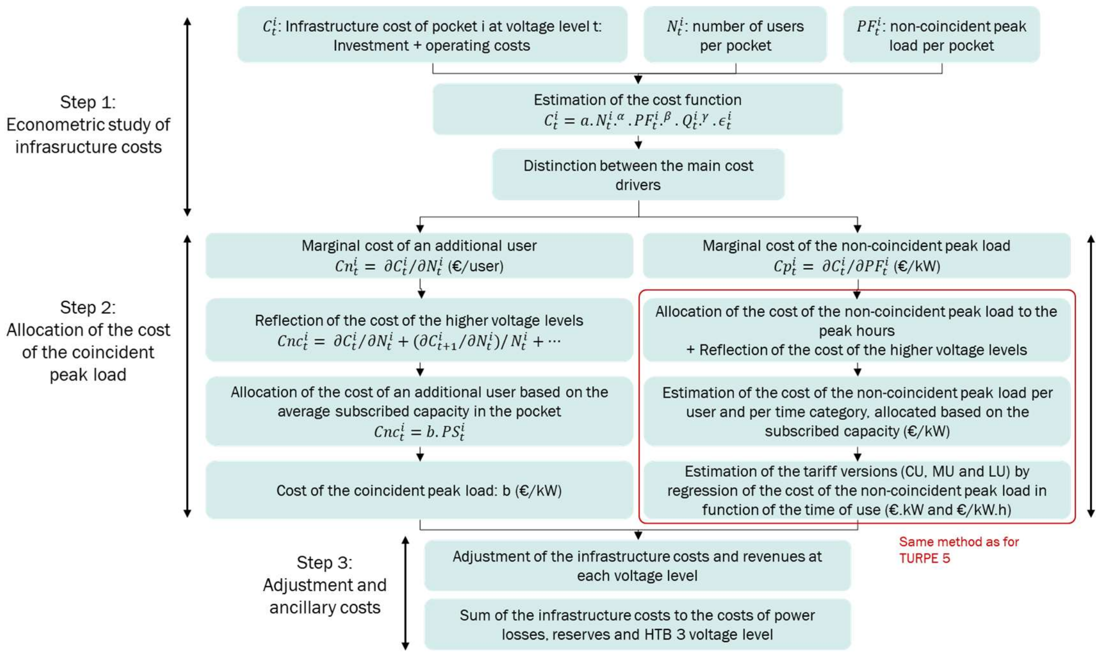

Figure 7 : Steps of the method adopted for TURPE 6

Cost allocation takes into account the fact that each user uses not only the voltage level 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 the method

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 coeffcients, similarly for each voltage level (except HTB3) 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 4.3.3.3);

- 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 duration: 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 expenses 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.

4.3.3.3 Changes made for the HTA voltage level following the public consultation of October 2020

CRE had thorough discussions with several participants having expressed their concerns within the framework of their responses to the public consultation of October 2020. These concerns concerned mainly the consequences of the increase in the capacity portion on the level of their bills, particularly for the HTA voltage level. These technical discussions, as well as the transmission of consumption data by these participants, highlighted unobservable effects on the panel of customers used to calibrate the level and changes in bills presented in the public consultation.

Concerning the HTA voltage level, CRE was able to observe that the tariffs presented in the public consultation of October were over-adjusted by almost 7%. To correctly reflect the costs of each voltage level, the level of tariffs is adjusted so that at iso-level 2020, the revenues by voltage level are similar between the TURPE 5 structure and the TURPE 6 structure. For this, CRE had to make assumptions about capacity subscriptions by customers connected in the HTA voltage level, which turned out to be inexact. This effect is corrected in the tariffs contained in section 5.2, so that the tariff revenues collected by Enedis from customers connected in the HTA range henceforth effectively cover the costs of this voltage level[55]. This problem did not occur for the other voltage levels.

In addition, still in the HTA voltage level, CRE had presented bill changes integrating the impact of the drop in the weighting coefficient for the monthly component for subscribed capacity overruns (CMDPS, see section 4.3.4). This

[55] In addition to the costs generated by these customers in the upstream voltage levels, as was already the case in the tariffs presented in the public consultation of October 2020.

drop enables, particularly for participants with the shortest use duration profiles, a finer optimisation of their subscribed capacity and therefore a limit on the bill increases associated with the change in the tariff structure. In anticipation of this capacity optimisation, CRE had applied an upward adjustment by +1.5% to the HTA tariffs in order to offset *ex ante* the loss in revenues for Enedis. Exchanges with customers or customer associations revealed that not all of them had integrated this parameter in their bill evolution simulations, but also drew CRE's attention to the fact that the optimisation of subscribed capacity was not immediate for customers, who will need time to change their optimisation strategy.

Sensitive to this argument, CRE therefore decides not to apply the 1.5% adjustment which assumes a perfect optimisation of customers as of the first year of TURPE 6 HTA-BT, while the shortfall for Enedis associated with this optimisation is not quantifiable *ex ante*. Too great of an adjustment applied too quickly would be prejudicial to customers not being able to achieve this optimisation. CRE reiterates moreover, that the CRCP mechanism allows *ex post* correction of Enedis's tariff shortfalls or surpluses.

The HTA tariffs presented in section 5.2 are therefore, at TURPE 5 iso-level, 8.5% lower than those presented in the public consultation of October 2020, thus making bill developments more acceptable for the customers most affected by the methodology changes.

Despite the changes presented above in the HTA voltage level, the development in the methodology for constructing the withdrawal component can generate substantial changes for certain types of users, particularly those under short 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 methodology over the TURPE 6 HTA-BT tariff period for the BT > 36 kVA and HTA 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. Therefore, similar to the smoothing specified for the BT > 36 kVA level within the framework of the generalisation of options with four time categories, a reference BT > 36 kVA and HTA tariff is specified for each year of the TURPE 6 HTA-BT 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.

4.3.4 Monthly component for subscribed capacity overruns

Pricing of capacity overruns aims to encourage participants to subscribe the capacity level corresponding to their use, and they thus contribute their fair share to the coverage of the grid costs they generate. Pricing of overruns is also justified by the fact that network infrastructure has a certain thermal inertia enabling it to tolerate capacity overruns over short periods not calling into question the sizing of the network.

In TURPE 5, the monthly component for subscribed capacity overruns was calculated using the following formula:

$$CMDPS = \sum CP * b_i * \sqrt{\sum(\Delta P^2)}$$

- *CP:* designates the weighting coefficient of the CMDPS (no unit);
- b_i: designates the capacity-weighting coefficient of time category i;
- *ΔP*: designates the capacity overrun in kW by 10-minute interval compared to the subscribed capacity of the time category.

The same formula was applied for pricing of capacity overruns in the HTB voltage level. Nevertheless, the weighting coefficients differed for HTA and HTB, the HTA coefficient not having been revised for a long time unlike that for HTB.

During the public consultation of October 2020, CRE proposed readjusting the weighting coefficient for the HTA voltage level, aligning it with that of the HTB voltage level. This calibration makes the coefficient more consistent with the current tariff formulas and ensures that above overruns of 100 hours, it becomes more interesting to book additional capacity.

The great majority of participants were in favour of this alignment of the HTA coefficient with the HTB coefficient. Nevertheless, as previously stated, while this change enables users connected in the HTA range to control the bill changes associated with the development in the method for constructing the withdrawal component by optimising their subscribed capacity, feedback to the public consultation and exchanges led by CRE with participants since this consultation, showed that a significant portion of participants did not take into account the impact of the drop in the coefficient for overruns in their simulations.

Therefore, CRE sets the weighting coefficient for the HTA voltage level at 0.04 for TURPE 6, compared to 0.11 currently. In addition, it publishes for educational purposes, in annex 12 of the deliberation an illustration of optimisations of subscribed capacity enabled by the drop in this coefficient. Moreover, smoothing the structure changes introduced in TURPE 6 over four years (see section 4.3.3.3) gives all participants the necessary time to take into account this development and adapt their subscribed capacity levels accordingly.

4.3.5 Reactive energy billing

TURPE 5 HTA-BT specified different conditions for billing reactive energy for production installations in the HTA and in the BT > 36 kVA ranges:

- in the HTA voltage level, the reactive energy supplied or absorbed was billed to producers above certain thresholds, fixed by the system operator;
- in the BT > 36 kVA range, the producer committed, if it was not voltage controlled, to not absorbing reactive power, and as the case may be, was billed for the absorbed reactive energy at a price of €1.89/kVAr.h.

In a context of major development of renewable energy in the grids, the absorption of reactive power by decentralised electrical energy production installations can provide a service to the network and in certain cases, contribute to avoiding reinforcement costs and sometimes extension costs. In this regard, the order relating to the technical design and operational requirements for connection to the electricity networks of 9 June 2020, repealed article 9 of the order of 23 April 2008[56], which banned the absorption of reactive power for production facilities connected in the BT (low-voltage) range.

In its public consultations of July and October 2020, CRE proposed transposing to the BT>36 kVA voltage level the provisions applicable in the HTA (medium-voltage) range concerning the billing of absorption and the reactive energy supply of producers, i.e. leaving DSOs the possibility of defining thresholds (tg φ_{max_BT} and tg φ_{min_BT} values) above which the reactive energy flow supplied or absorbed would be billed. Participants were generally in favour of this proposal, some of them highlighting that the services which may be provided by production facilities, particularly in terms of voltage management, are insufficiently valued at the moment.

For the TURPE 6 period, TURPE adopts similar billing conditions for the HTA and BT > 36 kVA voltage levels. This alignment complies with article 54 of the order of 9 June 2020 which specifies that "*In all cases, the reactive power actually supplied or absorbed by a production unit within the limits mentioned in the present article and the method of control are determined by the electricity distribution system operator in compliance with the principles mentioned in its reference technical documentation depending on the grid's management needs*".

4.3.6 Distribution grouping component

The grouping component enables acknowledgement of the diversification of load for connection points close to a single user, in return for a payment by this user of a grouping component, depending on the length of the network connecting these two points.

In a context of the deployment of self-consumption, CRE proposed, during the public consultation of October 2020 to specify the application conditions for this possibility of conventional grouping, in order to clarify the fact that this component does not aim to enable netting of withdrawals by injections in the case where production facilities and withdrawal points are grouped.

Most contributors to the public consultation were in favour of this proposal. CRE specifies (see section 5.2.1.8) that if grouping concerns both production facilities and withdrawal points, any possible injection flows cannot be deducted from the withdrawal flows for the calculation of the annual withdrawal component.

4.4 Generalisation of the option with four time categories

In the context of the deployment of the Linky smart meter, CRE introduced in TURPE 5 HTA-BT tariffs with four time categories for the BT ≤ 36 kVA voltage level. However, because of the still limited proportion of Linky meters deployed and for the purpose of gradual migrations between options as well as gradual bill increases, the options for short use without seasonal differences (CU, single rate) and for medium use with time differences (MU DT, differentiating peak and off-peak times) were maintained.

As of 31 August 2020, 11.7 million users of Enedis's grid, out of a total 36.8 million, chose an option with four time categories through their supplier.

In the long term, CRE considers that maintaining tariff options without seasonal differentiations is not desirable, since they do not encourage all suppliers and users to make efforts in terms of innovation and energy efficiency

[56] Ministerial order of 23 April 2008, relating to the technical requirements regarding design and operation for low-voltage or medium-voltage connection to a public electricity distribution network of a power production installation

during peak periods for the networks which are mostly concentrated in winter, and thus, contribute to controlling grid costs in the long run.

CRE stated on several occasions and most recently in the public consultation of October 2020, its objective of generalising the tariff with four time categories for all users in the long term. Since this generalisation depends on the acceptability of the associated bill changes, CRE proposed in its different public consultations a gradual generalisation, ending in 2024.

Participants who gave their opinions in the public consultations of 2019 and 2020 are mostly in favour of this proposal. Some of them however highlight that the generalisation of the four time category option for the BT ≤ 36 kVA voltage level must not be prejudicial for the most precarious consumers and must be associated with support for the customers concerned. One participant considers, moreover, that this change is not suitable for non-interconnected zones, where consumption is not as seasonal as in mainland France.

As it stated in its public consultation of October 2020, CRE agrees with the necessity to ensure acceptability of bill increases by certain customers, particularly the most precarious. It conducted an analysis on bill changes to ensure that any increases were contained, by analysing in particular the customer profiles that might correspond to precarious situations.

Lastly, CRE highlights that the application of this generalisation to non-interconnected zones results from the principle of standardised tariff. It also reiterates that the local placement of months in the high season enables DSOs to ensure that pricing is consistent with the load status of the networks. The DSO can therefore decide locally on a specific placement of high and low seasons given the local consumption characteristics.

CRE therefore adapts the generalisation for 2024 of the four time category option for the BT≤ 36 kVA voltage level. The construction of the associated tariffs as well as the timetable and conditions for generalisation, presented in the sections below, take into account the attention paid by CRE to the acceptability of this measure.

4.4.1 Timetable and conditions envisaged for generalisation

The general four time category option over the TURPE 6 period results in the elimination of options without seasonal variations (CU and MU DT) in August 2024, for the last year of the tariff period. In order to smooth, over the TURPE 6 HTA-BT period, the bills evolutions resulting from the elimination in 2024 of the CU and MU DT options, CRE will progressively increase between 2021 and 2023 the tariff for these options and will simultaneously reduce the tariff for the four time category option.

The smoothing will, through the gradual increase in options without time/season differences, have the effect of "emptying" those options progressively. On an indicative basis, the number of customers for whom it would be wise to subscribe an option without time/season differentiation should evolve as follows over the TURPE 6 period:

Table 32 : Change in the portion of clients having an interest in subscribing a TURPE option without time/season differentiation

	2021	2022	2023	2024
Portion of CU and MU DT clients	36%	26%	17%	4% (non Linky clients)

The present deliberation defines, for each year of the TURPE 6 HTA-BT period, reference tariffs taking into account all of these gradual structure developments. The corresponding tariffs are presented in section 5.2.2.2. 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.

4.4.2 Treatment of users not equipped with smart meters

The generalisation of the four time category options for 2024 raises the question of the treatment in 2024 of users without smart meters, either because they refuse to have it installed, or because they have not yet benefited from the deployment. According to the deployment plan specified by Enedis, the rate of users not having Linky meters by 2024 will be 4%, i.e. 1.5 million delivery points. The problem is also raised outside Enedis's serving zone, where deployment takes place at later dates. In that regard, EDF SEI and Gérédis respectively project the installation of 83% and 60% of smart meters in their serving zones by 31 December 2024.

Some customers therefore will not be eligible for the TURPE 4 four time category options CU4 and MU4 in 2024. CRE, during its consultations of March and October 2020 proposed a solution consisting in conserving the options without time/season differentiations as derogations, only accessible to these clients, with the same structure level (i.e. excluding the average annual update of the tariff level) as in 2023. Participants expressing their views were all in favour of this proposal. CRE therefore adopts this principle in the present deliberation.

In addition, with regard to clients that will have refused Linky, CRE reiterated in its previous public consultations of 2020 that a portion of the savings brought by the Linky programme are related to the drop in metering costs made possible by the end of meter visits. Therefore, any client having refused the installation of a smart meter will negatively affect the gains brought by the project. CRE considers that it will therefore be necessary to pass the residual metering costs onto these clients alone. This proposal was well-received by most participants in the public consultations, some of them however expressing the difficulty in distinguishing between all of the possible reasons for the non-installation of a Linky meter at a customer's location.

The billing conditions of these costs will be fixed by CRE by the end of massive deployment (90% of meters installed), scheduled for 2021.

4.5 Pricing of self-consumption

CRE's TURPE 5 HTA-BT deliberation and its deliberation of 7 June 2018[57] update the billing conditions for the use of the grids for individual self-consumers and participants to collective self-consumption operations:

- the management component applicable to individual self-consumers was lowered, so as to not make self-consumers bear two management components;
- a management component was introduced, for participants to collective self-consumption operations, to take into account the complexity of management caused for Enedis, responsible in particular for the retreatment of load curves;
- an option devoted to the withdrawal component was open only for participants to collective self-consumption operations where all participants are connected downstream of the same HTA/BT transformer substation.

When these rules were implemented, fewer than 14,000[58] individual self-consumers were connected to the distribution network and no collective self-consumption operation was active. CRE had indicated at the time that it would obtain feedback on these provisions, within the framework of the preparatory work for TURPE 6 HTA-BT.

To date, more than 86,000 individual self-consumers are connected to the grids managed by Enedis[59]. Moreover, as at the end of November 2020, Enedis identified 41 collective self-consumption operations active as at the end of August (including extended operations, see section 4.5.3), bringing together 607 participants (529 consumers and 78 producers), the majority of which are led by municipalities and social landlords, sometimes through an association. In addition, Enedis identifies 45 other operations declared as projects. Enedis was able, at the request of CRE, to obtain feedback on these operations. Although the depth of the historical data available is still limited, initial conclusions were able to be drawn and were presented in the public consultation of October 2020.

4.5.1 Specific management component

Whether relating to individual or collective self-consumption, the management costs evaluated by Enedis for these clients remain higher than the revenues collected to date through the specific management component that they pay.

CRE notes however that self-consumption is still a recent phenomenon which is fully developing. The number of Enedis's clients concerned increases sharply each year, and the resources that Enedis must use for their management change accordingly (manual management of clients by specific teams, choice of IS system more or less substantial, etc.). CRE estimates that the costs currently borne by Enedis for the management of individual self-consumers or participants to collective self-consumption operations are not representative of future costs, which are hard to foresee. For example, a greater number of individual self-consumers or participants to collective self-consumption operations will require more significant IS developments, but will also enable rationalisation of the treatment of these clients, leading to a drop in the unit management cost for these clients.

[57] CRE deliberation of 7 June 2018 deciding on the pricing of self-consumption, and amendment of CRE's deliberation of 17 November 2016 deciding on the tariffs for the use of the public electricity grids in the HTA and BT voltage levels (medium voltage and low voltage) (https://www.cre.fr/Documents/Deliberations/Decision/Tarification-Autoconsommation-et-modification-deliberation-TURPE-HTA)
[58] Self-consumption installations connected to the network managed by Enedis as at the end of Q2 2017 (https://www.enedis.fr/open-data-le-mix-par-enedis)
[59] Self-consumption installations connected to the network managed by Enedis as at the end of Q3 2020 (https://www.enedis.fr/open-data-le-mix-par-enedis)

Therefore, CRE had envisaged in the public consultation of October 2020 maintaining for TURPE 6 the same level of the management component for individual self-consumers and participants to collective self-consumption operations. Most contributors are in favour. These components will not be changed in TURPE 6 HTA-BT. They will follow the annual updates of the tariff level applied to the “classic” management components.

For collective self-consumption, the management component remains applicable to all collective self-consumption operations referred to in article L.315-2 of the energy code, whether they involve a single building or are “extended”, including for operations where all of the participants are not located downstream of a same HTA/BT transformer substation.

4.5.2 Withdrawal component for collective self-consumption

The optional withdrawal component, introduced by the deliberation of 7 June 2018, is an 8-index option, which enables collective self-consumption operations where all of the participants are connected downstream of the same HTA/BT transformer substation to take advantage of the distinction between *autoproduits* withdrawals (corresponding to the energy generated by the production facilities taking part in the operation) and *alloproduits* withdrawals (corresponding to the difference between consumption and production attributed to the user of the operation). The tariff includes, for each of the four time categories (high period / low period; peak / off-peak times), two coefficients:

- the first coefficient applies to *autoproduits* flows. It is lower than the TURPE coefficient with four time categories corresponding to this period, to take into account the local nature of production from which this flow originates: the “cost cascading” considered only takes into account the costs of the low-voltage network (as well as part of the costs of the upstream voltage level, see below);
- the second coefficient applies to *alloproduits* flows and is, on the contrary, higher than the TURPE coefficient with four time categories corresponding to this period: by symmetry, decentralised production is no longer taken into account in the calculation of the cost cascading corresponding to these flows, coming from upstream voltage levels, since they are not *autoproduits*.

Such a tariff reduces the price paid by participants of collective self-consumption operations who can maximise their self-production at critical grid times while lowering their *alloproduits* withdrawals in general and especially at critical times.

With regard to the determination of the level of the coefficients applying to *autoproduits* flows, CRE had considered in 2018 that a part of these flows (30%) however generated flows in the upper voltage levels (given the effect of netting between injections and withdrawals within the 30-minute interval over which the sum of injections and withdrawals is considered). In other words, it was considered that a withdrawal of 1 kWh *autoproduits* over a given time interval had in reality generated a flow of 0.3 kWh over the upstream voltage levels by the effect of netting. On this basis, CRE had decided, in order to determine the level of the coefficients applicable to the *autoproduits* flows, to add to the costs of the BT network, a contribution of 0.3 kWh per kWh withdrawn to the costs of the grids in the upstream voltage levels.

CRE had stated that this conservative assumption was justified by the lack of feedback on these operations and it committed to obtaining feedback within the framework of the preparatory work for TURPE 6 HTA-BT.

Enedis’s analyses, whose conclusions were detailed in the public consultation of October 2020, showed that the subscription of the collective self-consumption tariff option was most often preferable for clients and enabled them to reduce their bill compared to the “classic” options.

These analyses performed on all active collective self-consumption operations for which a one-year record was available therefore tend to invalidate stakeholders’ feedback according to which this tariff would not be advantageous compared to the classic options: most participants in these operations would, in retrospect, have had an interest in subscribing to this option.

The value of subscribing the specific option, moreover, will grow once the options with four time categories are generalised: since the self-consumption option currently is only available in a four time category version, participants with consumption profiles that vary the most by season may be encouraged currently to decide on an offer with no season variations, independently of their rate of self-consumption.

Lastly, this study confirms the incentive nature of this tariff: the higher the self-consumption rate of participants, the greater the benefit brought by the self-consumption option.

On the basis of these analyses and the favourable feedback from participants, CRE therefore adopts for the TURPE 6 HTA-BT period an optional withdrawal component aimed at participants in collective self-consumption operations where all of the participants are connected downstream of the same HTA/BT transformer substation, with four time categories and based on the distinction between *autoproduits* withdrawals and *alloproduits* withdrawals.

The new tariffs however no longer include the allocation to *autoproduits* flows of 30% of upstream flows which increased the costs of the *autoproduits* flows. Enedis's analyses on two existing sites, whose conclusions were shared in the public consultation of October 2020, showed that the phenomenon of net metering produced from a measurement of a 30-minute interval is very limited and therefore does not justify maintaining this conservative assumption. All other things being equal, this change will have the effect of making *autoproduits* flows cheaper and thus strengthening the incentive to maximise the self-production rate. In addition, the tariff coefficients associated with this option change because of the evolution in the method for determining the withdrawal component specified in section 4.3.3, and therefore present a greater seasonal differentiation, but also a smaller time-of-day differentiation within the same season.

The resulting tariffs are specified in section 5.2.

Lastly, given the favourable opinions received by participants within the framework of the public consultation of 8 October 2020, participants leaving a collective self-consumption operation are exempt from the rule requiring them to subscribe a tariff formula for 12 consecutive months if they subscribed to the specific option for collective self-consumption, so that they do not bear any TURPE bill increases due to the subscription of a tariff option no longer corresponding to their situation.

4.5.3 Evolution in the scope of collective self-consumption operations

The deliberation of 7 June 2018 relating to the billing of self-consumption, followed by the TURPE 5 bis HTA-BT deliberation defined a collective self-producer as a "*user participating in a collective self-consumption operation, as defined by the provisions of article L.315-2 of the energy code, for which all of the withdrawal and injection points of participants are located downstream of the same medium-voltage to low-voltage (HTA/BT) transformer substation.*"

The provisions of article L.315-2 of the energy code have been amended since then. They henceforth specify that "*The self-consumption operation is collective once the electricity supply is performed between one or more producers and one or more end customers joined together within one legal entity and whose withdrawal and injection points are located in the same building, including residential buildings. A collective self-consumption operation can be qualified as extended once the electricity supply is performed between one or more producers and one or more end customers joined together within one legal entity and whose withdrawal and injection points are located in the low-voltage network and comply with the criteria, in particular geographical proximity, fixed by the order of the Minister of Energy, after an opinion by the Energy Regulatory Commission*".

As stated in section 4.5.1, all collective self-consumption operations generate additional management costs for the system operator, which justifies a specific management component being applied to participants in all of these operations, including extended operations.

As for the optional withdrawal component, CRE stated in its opinions relating to the changes in the scope of collective self-consumption operations[60], that this component could only be proposed to participants of operations where all of the participants are connected downstream of the same HTA/BT transformer substation. The very construction of this option is based on the distinction between the contributions to the grid infrastructure costs of the different voltage levels, and is not relevant if the *autoproduits* flows pass through the HTA network.

Contributors to the public consultation mostly agreed with CRE's analysis. One participant however proposed a system in which the specific tariff option would be accessible to participants connected downstream of the same HTA/BT transformer substation as the participating producer: the tariff option would then be robust against the broadening of the scope of operations, with some participants being eligible for the tariff and others not, within the same extended self-consumption operation. CRE takes note of this possibility but deems its implementation in the medium term too complex to be considered for TURPE 6. As for TURPE 5, the optional withdrawal component can only apply in TURPE 6 to participants of operations where all of the participants are connected downstream of the same HTA/BT transformer substation.

With regard to operations not meeting this criterion, extended or not, CRE considers, given the meshing of grids as of the HTA level, that their characteristics cannot justify the determination of a withdrawal component distinct to that applying to the rest of grid users.

[60] CRE deliberation no. 2019-215 of 26 September 2019 rendering an opinion on the draft order made under article L.315-2 of the energy code defining the geographical proximity of collective self-consumption and CRE deliberation no. 2020-130 of 11 June 2020 rendering an opinion on the draft order amending the order of 21 November 2019 defining the criterion of geographical proximity of extended collective self-consumption

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

5.1 Tariff rules

5.1.1 Definitions

For the application of the present 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).

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 Individual self-producer with injection

User equipped with a production installation and holding, for a same connection point, a contract for network injection and a contract for network withdrawal, or a grid access contract associating injection and withdrawal.

5.1.1.4 Individual self-producer without injection

User equipped with a production installation and who does not hold a grid access contract for withdrawal.

5.1.1.5 Collective self-producer

User participating in a collective self-consumption operation, as defined by the provisions of article L. 315-2 of the energy code.

5.1.1.6 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.

5.1.1.7 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[61].

5.1.1.8 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 withdrawn.

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 integration period, the value of these variables is brought for each integration period to their average value during this period.

5.1.1.9 Metering system

The metering system is composed of all the active and/or reactive energy meters at a given metering point, including related cabinets, boxes and panels, as well as, if needs be, the following complementary items of equipment: low voltage and current transformers (CT), pricing signal receivers, synchronisation systems, devices for pricing conversion of metering data, communication interfaces for meter reading, control systems to limit demand, and test boxes.

A smart meter is a metering device connected to the telecommunications networks, configurable and consultable remotely from information systems managed by the public system operator. Flow metering and control at the connection point of the installation are automated.

5.1.1.10 Voltage level

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

Table 33 : Voltage level according to connection voltage

<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">BT</td><td>Low voltage level</td></tr>
<tr><td>1 kV < $U_n \leq 40$ kV</td><td>HTA 1</td><td rowspan="2">HTA range</td><td rowspan="3">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>HTB range</td></tr>
</table>

[61] The grid access contract is signed with the public system operator either by the user, or by any company, selling electricity to clients having exercised their right to choose their supplier or, if this company and the operator are not distinct legal persons, a protocol relating to grid access for the execution of supply contracts signed by this company with end customers having exercised their right to choose their supplier.

130 kV < $U_n \leq$ 350 kV	HTB 2		
350 kV < $U_n \leq$ 500 kV	HTB 3		

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

5.1.1.11 Supply of reactive power

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

5.1.1.12 Index

Energy indices represent the time integration of the root mean square values of power, separately for each quadrant, from a selected time origin.

5.1.1.13 Active power injection

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

5.1.1.14 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.

5.1.1.15 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.

5.1.1.16 Transformers

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

5.1.1.17 C_{card} parameter

Additional cost incurred by the DSO for the management of clients having signed a grid access contract directly with the DSO for the voltage level in question.

5.1.1.18 Rf parameter

Average amount taken into account for the financial considerations paid to suppliers for their management of clients on behalf of DSOs.

5.1.1.19 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.

5.1.1.20 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 current rules, for a user with several HTA connection points on the public grid, it is considered that all or part of these points are mixed, if under normal operating conditions of the user's electrical equipment contractually agreed with the public system operator(s), they are connected by this user's electrical equipment to the connection voltage.

5.1.1.21 Tariff item

For all tariffs for the use of the public electricity grids, the tariff item is the category of withdrawals for which the same tariff coefficients apply.

5.1.1.22 Profiling

System used by public system operators to calculate consumption or production, half-hour by half-hour, of users for whom flow reconstitution is not done using a load curve, in order to determine the differences for their balance responsible parties. This system is based on the determination, for categories of users, of the form of their consumption or production (profiles).

5.1.1.23 Active power (P)

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

5.1.1.24 Apparent power (S)

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

5.1.1.25 Reactive power (Q) and reactive energy

Reactive power Q is equal to active power produced 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.

5.1.1.26 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.

5.1.1.27 Load transfer

TURPE 6 HTB provides that 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).

When RTE implements such a load transfer, under the conditions specified by TURPE 6 HTB, the subscribed power 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 power overruns set out in the present deliberation when these supplies are connected in the HTA 2 voltage level. The quantities of energy withdrawn by the backup supply are billed at the tariff for main supply and only overruns above the subscribed power for main supply are billed.

TURPE 6 HTB provides that, 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 transmission grid access contract.

5.1.1.28 Withdrawal of active power

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

5.1.1.29 User

A user of a public transmission or distribution 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 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 withdrawal power subscribed by the user and the metering system deployed. The withdrawal capacity subscribed is defined at the start of a period of 12 consecutive months for all of this period. The grid access contract specifies the conditions under which the subscribed withdrawal capacity can be changed during this period.

5.2 Tariffs for the use of the public electricity distribution grid

5.2.1 Tariffs as at 1 August 2021

5.2.1.1 Annual management component (CG)

The annual management component of the grid access contract covers the management costs for user files, physical and telephone reception of users, billing and collection. Its amount depends on the conditions for the establishment of this contract by the public grid operator concerned either directly with a user of this grid, or with the company that ensures exclusive supply of the consumption site in accordance with article L.111-92 of the energy code.

The annual management component of an access contract signed with a supplier is also applicable to:

- consumers who have not exercised the right granted in Article L. L.331-1 of the French Energy Code;
- users benefiting from a purchase tariff prior to law no. 2000-108 of 10 February 2000 as amended.

The annual management component (CG) is determined for each connection point of one or more main power supplies and for each access contract.

The amounts of the annual management component are rounded off to the nearest 12 euro cents.

The amount of the annual management component billed is equal to the sum:

- of an R_f parameter if the grid access contract is signed with the supplier, or a C_{card} parameter if the grid access contract is signed with the user;
- and the amount of the annual management component excluding the R_f and C_{card}, whose amount applicable from 1 August 2021 to 31 July 2022 is as follows:

Table 34 : Annual management component excluding R_f and C_{card} applicable from 1 August 2021 to 31 July 2022

CG (€/year)	Grid access contract signed by user (excluding C_{card})	Grid access contract signed by supplier (excluding R_f)
HTA	213.23	213.23
BT > 36 kVA	106.61	106.61
BT ≤ 36 kVA	7.46	7.46

For individual self-producers with injection, the management component billed is equal to the sum of the amount of the management component associated with a grid access contract signed by the user (including C_{card}), and half of the amount of the management component associated with a grid access contract signed by the supplier (including R_f).

The amounts of the annual management component of individual self-producers with injection are rounded off to the nearest 12 euro cents.

The annual management component of individual self-producers with injection applicable from 1 August 2021 to 31 July 2022 is as follows:

Table 35 : Management component excluding R_f and C_{card} from 1 August 2021 to 31 July 2022 for individual self-producers with injection

CG (€/year)	Individual self-producers with injection
HTA	319.84
BT > 36 kVA	159.92
BT ≤ 36 kVA	11.19

For individual self-producers without injection, the annual management component billed is equal to the management component excluding the R_f or C_{card} coefficient to which is added the R_f or C_{card} coefficient.

The amounts of the annual management component of individual self-producers without injection are rounded off to the nearest 12 euro cents.

The annual management component for individual self-producers without injection applicable from 1 August 2021 to 31 July 2022 is as follows:

Table 36 : Management component excluding R_f and C_{card} for individual self-producers without injection from 1 August 2021 to 31 July 2022

CG (€/year)	Grid access contract signed by user (excluding C_{card})	Grid access contract signed by supplier (excluding R_f)
HTA	213.23	213.23

BT > 36 kVA	106.61	106.61
BT ≤ 36 kVA	7.46	7.46

For collective self-producers, the annual management component billed is equal to the management component excluding the R_f or C_{card} coefficient increased by 50%, to which is added the R_f or C_{card} coefficient[62].

The amounts of the annual management component for collective self-producers are rounded off to the nearest 12 euro cents.

The annual management component for collective self-producers applicable from 1 August 2021 to 31 July 2022 is as follows:

Table 37 : Management component excluding R_f and C_{card} for collective self-producers applicable from 1 August 2021 to 31 July 2022

CG (€/year)	Grid access contract signed by user (excluding C_{card})	Grid access contract signed by supplier (excluding R_f)
BT > 36 kVA	159.92	159.92
BT ≤ 36 kVA	11.19	11.19

[62] In the case where the collective self-producer is also an individual self-producer with injection, the management component billed is equal to the management component of individual self-producers with injection. If the collective self-producer is also an individual self-producer without injection, the management component billed is equal to the management component of collective self-producers.

5.2.1.2 Annual metering component (CC)

The annual metering component covers the costs of metering, control, reading, transmission of metering data (these are submitted to the user or a third party authorised by them at minimum intervals defined in table 39), costs related to the process of flow reconstitution, as well as, where applicable, rental and maintenance costs for the metering system.

It is established based on the subscribed power and the voltage level according to table 39. The values measured by the user's measuring and control equipment must enable the calculation of the components of the tariff for the use of the public grids.

If there are no metering devices, the public grid operators can provide for transparent and non-discriminatory methods for estimating energy flows injected or withdrawn and subscribed power, based on the rules published in their reference technical documentation. In this case, the amount of the annual metering component is defined in table 38 below.

The amounts of the annual management component are rounded off to the nearest 12 euro cents.

The annual metering component applicable from 1 August 2021 to 31 July 2022 to users without metering devices is as follows:

Table 38 : Annual metering component applicable from 1 August 2021 to 31 July 2022 – Users without metering device

Metering component (€/year)
1.45

The annual metering component billed to users equipped with a metering system is defined in table 39 below, according to the voltage level and the withdrawal power subscribed and/or maximum injection power.

The annual metering component applicable from 1 August 2021 to 31 July 2022 to users equipped with a metering device is as follows:

Table 39 : Annual metering component applicable from 1 August 2021 to 31 July 2022 – Users with a metering device

Voltage level	Power (P)	Minimum transmission frequency	Annual metering component (€/year)
HTA	-	Monthly	312.12
BT	P > 36 kVA	Monthly	234.90
	P ≤ 36 kVA	Bi-monthly or half-yearly[63]	18.24

5.2.1.3 Annual injection component (CI)

The annual injection component applicable from 1 August 2021 to 31 July 2022 is established at each connection point, based on the active energy injected into the public grid, according to the table below:

Table 40 : Annual injection component applicable from 1 August 2021 to 31 July 2022

Voltage level	€c/MWh
HTA	0
BT	0

[63] For users with smart metering devices in the low-voltage network and for power lower than or equal to 36 kVA, the minimum frequency of transmission of billing data is bi-monthly. In the other cases, it is half-yearly.

5.2.1.4 Annual withdrawal components (CS) and monthly components for subscribed power overruns (CMDPS) for the medium voltage level (HTA)

For the establishment of their annual withdrawal component for the HTA voltage level, users choose, for each connection point and for the entire duration of a period of 12 consecutive months (except with regard to the transitional provision specified in section 5.2.1.14), one of the four tariffs below:

- tariff with five time categories, fixed peak times, long use;
- tariff with five time categories, mobile peak times, long use;
- tariff with five time categories, fixed peak times, short use;
- tariff with five time categories, mobile peak times, short use.

For each of their connection points in the HTA voltage level, and for each of the five time categories of the tariff option chosen, users choose subscribed capacity P_i in multiples of 1 kW, where *i* designates the time category. Whatever the value of *i*, subscribed power must be such that $P_{i+1} \geq Pi$.

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

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

P_i designates the subscribed capcity for the nth time category, expressed in kW.

Ei designates the active energy withdrawn during the nth time category, expressed in kWh.

5.2.1.4.1 HTA tariff with five time categories and fixed peak times

For the HTA tariff with five time categories and fixed peak times, the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 for short- and long-use tariffs are respectively those in table 41 and 42 below:

Table 41 : HTA tariff with 5 time categories and fixed peak times applicable from 1 August 2021 to 31 July 2022 – short use

	Fixed 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 = 4.88	b_2 =4.67	b_3 =4.40	b_4 = 4.26	b_5 = 3.60
Energy-based coefficient (€c/kWh)	c_1 = 3.73	c_2 =3.20	c_3 =2.17	c_4 = 1.64	c_5 = 1.01

Table 42 : HTA tariff with 5 time categories and fixed peak times applicable from 1 August 2021 to 31 July 2022 – long use

	Fixed 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 = 19.36	b_2 = 18.26	b_3 =13.85	b_4 = 9.71	b_5 = 4.15
Energy-based coefficient (€c/kWh)	c_1 = 2.80	c_2 = 2.11	c_3 = 1.38	c_4 = 0.89	c_5 = 0.77

The time categories are defined locally by the public system operator based on the operating conditions of the public grids. They are communicated to any person that so requests it and published on the website of the public system operator or, if there is no such site, by any another appropriate means.

The high seasons include the months of December to February[64], and sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods. The other periods make up the low season. By default, the high season includes the months of November to March. Any change shall be submitted previously by the DSO to a consultation process.

Peak times are defined, from December to February inclusive[65], with two hours in the morning between 8.00 a.m. and noon and two hours in the evening between 5.00 p.m. and 9.00 p.m. Sundays are included fully in the off-peak category. The other days include eight peak hours defined by the DSO, 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.

5.2.1.4.2 HTA tariff with five time categories and mobile peak times

For the HTA tariff with five time categories and mobile peak times, the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 for the short- and long-use tariffs are respectively those in table 43 and 44 below:

[64] In non-interconnected zones (ZNI), the high season comprises three consecutive months, and 61 days distributed so that during the same calendar year, the high season does not comprise more than three separate periods.
[65] Or in the ZNI, during a period of three consecutive months falling within in the high season.

Table 43 : HTA tariff with 5 time categories and mobile peak times applicable from 1 August 2021 to 31 July 2022 – short use

	Mobile 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)	$b_1 = 5.34$	$b_2 = 4.61$	$b_3 = 4.40$	$b_4 = 4.26$	$b_5 = 3.60$
Energy-based coefficient (€c/kWh)	$c_1 = 4.78$	$c_2 = 3.07$	$c_3 = 2.17$	$c_4 = 1.64$	$c_5 = 1.01$

Table 44 : HTA tariff with 5 time categories and mobile peak times applicable from 1 August 2021 to 31 July 2022 – long use

	Mobile 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)	$b_1 = 21.81$	$b_2 = 19.93$	$b_3 = 13.85$	$b_4 = 9.71$	$b_5 = 4.15$
Energy-based coefficient (€c/kWh)	$c_1 = 3.21$	$c_2 = 1.93$	$c_3 = 1.38$	$c_4 = 0.89$	$c_5 = 0.77$

The time categories are defined locally by the public system operator based on the operating conditions of the public grids. They are communicated to any person that so requests it and published on the website of the public system operator or, if there is no such site, by any another appropriate means.

The high season includes the months of December to February[66], and sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods. The other periods make up the low season. By default, the high season includes the months of November to March. Any change shall be submitted previously by the DSO to a consultation process.

Sundays are included fully in the off-peak category. The other days include eight peak hours defined by the DSO, 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. Mobile peak times are the times in the PP1 period in the capacity mechanism[67].

5.2.1.4.3 Monthly component for subscribed power overruns (CMDPS)

For users of a connection point situated in the HTA voltage level, the monthly components for subscribed capacity overruns relating to this point are established each month based on the terms below:

$$CMDPS = \sum_{classes\ i\ du\ mois} 0{,}04 * b_i * \sqrt{\sum(\Delta P^2)}$$

ΔP: designates the capacity overrun in kW by 10-minute interval compared to the subscribed capacity of the time category.

The b_i coefficients to be applied are those of sections 5.2.1.4.1 and 5.2.1.4.2, depending on the option chosen.

[66] By way of exception, in the ZNI, the high season comprises three consecutive months, and 61 days distributed so that during the same calendar year, the high season does not comprise more than three separate periods.
[67] If a change in the capacity mechanism eliminated the peak period PP1 or modified it significantly, CRE could request RTE nevertheless to draw PP1 days as defined currently, i.e. 10 to 15 days per year, from 7.00 a.m. to 3.00 p.m., and from 6.00 p.m. to 8.00 p.m., so that the tariff option with mobile peak periods can be implemented.

5.2.1.5 Annual withdrawal components (CS) and monthly components for subscribed capacity overruns (CMDPS) for the low-voltage BT > 36 kVA range

For the establishment of their annual withdrawal component for the BT voltage level strictly higher than 36 kVA, users choose for the entire duration of a period of 12 consecutive months (except with regard to the transitional provision specified in section 5.2.1.14 or any specific provision for collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT transformer substation presented below) one of the two tariffs with time differentiation below:

- short-use tariff with four time categories;
- long-use tariff with four time categories.

Collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same medium voltage to low voltage transformer substation (HTA/BT), can also subscribe to the following two tariffs:

- short-use tariff with four time categories – collective self-consumption (downstream of the same HTA/BT substation);
- long-use tariff with four time categories – collective self-consumption (downstream of the same HTA/BT substation);

The time categories are defined locally by the public system operator based on the operating conditions of the public grids. They are communicated to any person that so requests it and published on the website of the public system operator or, if there is no such site, by any another appropriate means.

The high season includes the months of December to February[68], and sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods. The other periods make up the low season. By default, the high season includes the months of November to March. Any change shall be submitted previously by the DSO to a consultation process.

All days include peak hours which are 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.

For collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation, the *autoproduits* withdrawals correspond to the portion of withdrawals self-consumed as calculated by the grid operators within the framework of the collective self-consumption operation, in accordance with the provisions of article L. 315-4 of the energy code. *Alloproduits* withdrawals correspond to withdrawals not self-consumed.

If a collective self-producer participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation and who has subscribed to the specific option for collective self-consumption, then leaves the collective self-consumption operation in which it participated, this self-producer can modify on one occasion the option and tariff version for the connection point in question without having to comply with the consecutive 12-month period since the previous tariff option.

For each of their connection points in the BT voltage level strictly higher than 36 kVA and for each of the time categories[69] defined in sections 5.2.1.5.1, 5.2.1.5.2, 5.2.1.3 and 5.2.1.5.4, users choose, in multiples of 1 kVA, a subscribed apparent capacity P_i where i designates the time category. Whatever the value of i, subscribed capacity must be such that $P_{i+1} \geq P_i$.

When control of subscribed apparent capacity overruns is ensured by a circuit breaker at the interface with the public grid, the subscribed apparent capacity is equal to the capacity adjustment by the surveillance equipment controlling the circuit breaker.

In addition, whatever the value of i, subscribed apparent 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:

$$CS = b_1 * P_1 + \sum_{i=2}^{4} b_i.(P_i - P_{i-1}) + \sum_{i=1}^{4} c_i.E_i$$

[68] By way of exception, in the ZNI, the high season comprises three consecutive months, and 61 days distributed so that during the same calendar year, the high season does not comprise more than three separate periods.

[69] Subject to the technical capacity of the meter and the information systems. The number of subscribed power possible per connection point cannot, in any case, be lower than 2.

P_i designates the subscribed apparent capacity for the nth time category, expressed in kVA.

Ei designates the active energy withdrawn during the nth time category, expressed in kWh.

By way of exception, for the connection points having selected a specific transmission tariff formula within the framework of a collective self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation, the annual withdrawal component is established based on the following formula:

$$CS = b_1 * P_1 + \sum_{i=2}^{4} b_i.(P_i - P_{i-1}) + \sum_{j=1}^{8} c_j.E_j$$

Pi designates the subscribed apparent capacity for the nth time category, expressed in kVA.

E_j designates the active energy withdrawn for the j^{th} tariff item, expressed in kWh.

5.2.1.5.1 Short-use, BT > 36 kVA tariff with four time categories

For the short-use BT > 36 kVA tariff with four time categories, the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 are those in the table below:

Table 45 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – short use

	High season peak times (i = 1)	High season off-peak times (i = 2)	Low season peak times (i = 3)	Low season off-peak times (i = 4)
Capacity-based coefficient (€/kVA/year)	b_1 = 11.61	b_2 = 7.11	b_3 = 5.90	b_4 = 3.74
Energy-based coefficient (€c/kWh)	c_1 = 5.15	c_2 = 3.36	c_3 = 2.28	c_4 = 1.80

5.2.1.5.2 Long-use, BT > 36 kVA tariff with four time categories

For the long-use BT > 36 kVA tariff with four time categories, the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 are those in the table below:

Table 46 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – long use

	High season peak times (i = 1)	High season off-peak times (i = 2)	Low season peak times (i = 3)	Low season off-peak times (i = 4)
Capacity-based coefficient (€/kVA/year)	b_1 = 20.57	b_2 = 12.51	b_3 = 10.48	b_4 = 5.95
Energy-based coefficient (€c/kWh)	c_1 = 4.43	c_2 = 3.11	c_3 = 2.00	c_4 = 1.70

5.2.1.5.3 Short-use BT > 36 kVA tariff with four time categories – collective self-production (downstream of the same HTA/BT substation)

For the short-use BT > 36 kVA tariff with four time categories – collective self-production (downstream of the same HTA/BT substation), the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 are respectively those in tables 47 and 48 below:

Table 47 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – short use – collective self-production (downstream of the same HTA/BT substation)

	High season peak times (i = 1)	High season off-peak times (i = 2)	Low season peak times (i = 3)	Low season off-peak times (i = 4)
Capacity-based coefficient (€/kVA/year)	b_1 = 11.67	b_2 = 6.87	b_3 = 5.34	b_4 = 3.40

Table 48 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – short use – collective self-production (downstream of the same HTA/BT substation)

	High season peak times *alloproduit* (j = 1)	High season off-peak times *alloproduit* (j = 2)	Low season peak times *alloproduit* (j = 3)	Low season off-peak times *alloproduit* (j = 4)	High season peak times *autoproduit* (j = 5)	High season off-peak times *autoproduit* (j = 6)	Low season peak times *autoproduit* (j = 7)	Low season off-peak times *autoproduit* (j = 8)
Energy-based coefficient (€c/kWh)	c_1 =5.24	c_2 =2.88	c_3 = 2.06	c_4 = 1.81	C_5 = 2.93	C_6 = 1.78	C_7 = 0.76	C_8 = 0.56

5.2.1.5.4 Long-use BT > 36 kVA tariff with four time categories – collective self-production (downstream of the same HTA/BT substation)

For the long-use BT > 36 kVA tariff with four time categories – collective self-production (downstream of the same HTA/BT substation), the coefficients b_i and c_i to be applied from 1 August 2021 to 31 July 2022 are respectively those in tables 49 and 50 below:

Table 49 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – long use – collective self-production (downstream of the same HTA/BT substation)

	High season peak times (i = 1)	High season off-peak times (i = 2)	Low season peak times (i = 3)	Low season off-peak times (i = 4)
Capacity-based coefficient (€/kVA/year)	b_1 = 21.05	b_2 = 12.82	b_3 = 9.95	b_4 = 5.84

Table 50 : BT > 36 kVA tariff with 4 time categories applicable from 1 August 2021 to 31 July 2022 – long use – collective self-production (downstream of the same HTA/BT substation)

	High season peak times *alloproduit* (j = 1)	High season off-peak times *alloproduit* (j = 2)	Low season peak times *alloproduit* (j = 3)	Low season off-peak times *alloproduit* (j = 4)	High season peak times *autoproduit* (j = 5)	High season off-peak times *autoproduit* (j = 6)	Low season peak times *autoproduit* (j = 7)	Low season off-peak times *autoproduit* (j = 8)
Energy-based coefficient (€c/kWh)	c_1 = 4.57	c_2 = 2.68	c_3 = 1.84	c_4 = 1.27	C_5 = 2.93	C_6 = 1.78	C_7 = 0.76	C_8 = 0.56

5.2.1.5.5 Monthly component for subscribed capacity overruns (CMDPS)

For users of a connection point located in the BT > 36 kVA voltage level, the monthly components for subscribed apparent capacity overruns relating to this point are established each month, for each of the time categories of the month in question, based on the duration of the overrun *h* (in hours) and according to the formula below:

$$CMDPS = \alpha * h$$

For the monthly component for subscribed capacity overruns in the BT > 36 kVA voltage level, the coefficient α used applicable from 1 August 2021 to 31 July 2022 is that in the table 51 below:

Table 51 : Monthly component for subscribed capacity overruns in the BT > 36 kVA range applicable from 1 August 2021 to 31 July 2022

α (€ / h)
10.29

Users whose CMDPS for all of the time categories is both 30% higher than their monthly TURPE bill and 25% higher than the tariff of the additional power they would have had to subscribe to avoid any overruns, can obtain a cap on their CMDPS for the month concerned at the highest of the two limits previously mentioned, upon request from the DSO.

5.2.1.6 Annual withdrawal component (CS) for the BT ≤ 36 kVA voltage level

For the establishment of the annual component for their withdrawals in the BT voltage level up to subscribed capacity of 36 kVA inclusive, users choose, for the entire duration of a period of 12 consecutive months (except with regard to the transitional provision specified in section 5.2.1.14 or the specific provision for collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are located downstream of the same HTA/BT substation presented below)), one of the following five tariffs, subject to the technical compatibility of the meter:

- tariff without time differentiation – short use;
- tariff with four time categories – short use;
- tariff with two time categories – medium use;
- tariff with four time categories – medium use;
- tariff without time differentiation – long use.

Collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation, can also subscribe to the following two tariffs:

- short-use tariff with four time categories – collective self-consumption (downstream of the same HTA/BT substation);
- medium-use tariff with four time categories – collective self-consumption (downstream of the same HTA/BT substation).

For the tariff of their choice, they define a subscribed capacity *P* in multiples of 1 kVA.

When control of subscribed capacity overruns is ensured by a circuit breaker at the interface with the public grid, the subscribed capacity is equal to the control power of the surveillance equipment controlling the circuit breaker.

At each connection point to the BT voltage level, up to subscribed capacity of 36 kVA inclusive, the annual withdrawal component is established according to the following formula:

$$CS = b * P + \sum_{i=1}^{n} c_i \, . E_i$$

Where:

- *P* designates subscribed capacity , expressed in kVA. For users with a monitored power connection it is equal to the capacity adjustment of the appropriate device;
- E_i designates the active energy withdrawn during the nth time category, expressed in kWh.

By way of exception, for the connection points having selected a specific transmission tariff formula within the framework of a collective self-consumption operation, the annual withdrawal component is established based on the following formula:

$$CS = b * P + \sum_{j=1}^{n} c_j . E_j$$

Where:

- *P* designates subscribed capacity , expressed in kVA. For users with a monitored capacity connection it is equal to the control capacity of the appropriate device;
- E_j designates the active energy withdrawn for the jth tariff item, expressed in kWh.

The time categories are defined locally by the public system operator based on the operating conditions of the public grids. They are communicated to any person that so requests it and published on the website of the public system operator or, if there is no such site, by any another appropriate means. The actual start and end times of the tariff periods can be different by a few minutes to the theoretical times of the time categories determined locally.

There are eight off-peak hours per day, which may be non-contiguous.

The high season includes the months of December to February[70], and sixty-one days, distributed so that during the same calendar year, the high season does not comprise more than three separate periods. The other periods make up the low season. By default, the high season includes the months of November to March. Any change shall be submitted previously by the DSO to a consultation process.

For collective self-producers participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation, the *autoproduits* withdrawals correspond to the portion of withdrawals self-consumed as calculated by the grid operators within the framework of the collective self-consumption operation, in accordance with the provisions of article L. 315-4 of the energy code. *Alloproduits* withdrawals correspond to withdrawals not self-consumed.

If a collective self-producer participating in a self-consumption operation where all of the withdrawal and injection points of participants are situated downstream of the same HTA/BT substation and who has subscribed to the specific option for collective self-consumption, then leaves the collective self-consumption operation in which it participated, this self-producer can modify on one occasion the option and tariff version for the connection point in question without having to comply with the consecutive 12-month period since the previous tariff option.

5.2.1.6.1 BT ≤ 36 kVA tariff without time differentiation – short use

For the short-use tariff, the coefficients *b* and *c* to be applied from 1 August 2021 to 31 July 2022 are those of tables 52 and 53 respectively:

Table 52 : BT ≤ 36 kVA tariff without time differentiation – short use, applicable from 1 August 2021 to 31 July 2022 – power portion

Period of application	b (€/kVA)
From 01/08/2021 to 31/07/2022	8.52[71]

Table 53 : BT ≤ 36 kVA tariff without time differentiation – short use, applicable from 1 August 2021 to 31 July 2022 – energy portion

c (€/kWh)c
3.71

[70] In the ZNI, the high season comprises three consecutive months, and 61 days distributed so that during the same calendar year, the high season does not comprise more than three separate periods.
[71] This coefficient is rounded off to 12 euro cents of the non rounded-off value of €8.49/kVA.

5.2.1.6.2 BT ≤ 36 kVA tariff with four time categories – short use

For the short-use tariff with four time categories, the coefficients *b* and c_i to be applied from 1 August 2021 to 31 July 2022 are those of tables 54 and 55 respectively:

Table 54 : BT ≤ 36 kVA tariff with 4 time categories – short use, applicable from 1 August 2021 to 31 July 2022 – power portion

Period of application	*b* (€/kVA/year)
from 01/08/2021 to 31/07/2022	8.40[72]

Table 55 : BT ≤ 36 kVA tariff with 4 time categories – short use, applicable from 1 August 2021 to 31 July 2022 – energy portion

c_1 High season peak times (€c/kWh)	c_2 High season off-peak times (€c/kWh)	c_3 Low season peak times (€c/kWh)	c_4 Low season off-peak times (c€/kWh)
6.27	4.29	1.34	0.83

5.2.1.6.3 BT ≤ 36 kVA tariff with two time categories – medium use

For the medium-use tariff with two time categories, the coefficients *b* and c_i to be applied from 1 August 2021 to 31 July 2022 are those of tables 56 and 57 respectively:

Table 56 : BT ≤ 36 kVA tariff with 2 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – power portion

Period of application	*b* *(€/kVA/year)*
from 01/08/2021 to 31/07/2022	10.32[73]

Table 57 : BT ≤ 36 kVA tariff with 2 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – energy portion

c_1 Peak times (€c/kWh)	c_2 Off-peak times (€c/kWh)
3,79	2.68

5.2.1.6.4 BT ≤ 36 kVA tariff with four time categories – medium use

For the medium-use tariff with four time categories, the coefficients b_i an c_i to be applied from 1 August 2021 to 31 July 2022 are those of tables 58 and 59 respectively:

[72] This coefficient is rounded off to 12 euro cents of the non rounded-off value of €8.44/kVA.
[73] This coefficient is rounded off to 12 euro cents of the non rounded-off value of €10.35/kVA.

Table 58 : BT ≤ 36 kVA tariff with 4 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – power portion

Period of application	*b* (€/kVA/year)
from 01/08/2021 to 31/07/2022	9.96[74]

Table 59 : BT ≤ 36 kVA tariff with 4 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – energy portion

c_1 High season peak times (€c/kWh)	c_2 High season off-peak times (€c/kWh)	c_3 Low season peak times (€c/kWh)	c_4 Low season off-peak times (c€/kWh)
5.75	3.99	1.31	0.82

5.2.1.6.5 BT ≤ 36 kVA tariff without time differentiation – long use

For the application of the long-use tariff without time differentiation, if there are no metering devices, the public system operators may specify transparent, objective and non-discriminatory methods for estimating the flows of energy withdrawn and subscribed power.

Power subscription is in increments of 0.1 kVA. The coefficients *b* and *c* to be applied from 1 August 2021 to 31 July 2022 are those of tables 60 and 61 respectively:

Table 60 : BT ≤ 36 kVA tariff without time differentiation – long use, applicable from 1 August 2021 to 31 July 2022 – power portion

b (€/kVA/year)
76.44[75]

Table 61 : BT ≤ 36 kVA tariff without time differentiation – long use, applicable from 1 August 2021 to 31 July 2022 – energy portion

c (€c/kWh)
1,04

5.2.1.6.6 BT ≤ 36 tariff with four time categories – short use - collective self-consumption (downstream of the same HTA/BT substation)

For the short-use tariff with four time categories specific to collective self-consumption (downstream of the same HTA/BT substation), the coefficients *b* and c_i to be applied from 1 August 2021 to 31 July 2022 are those of tables 62 and 63 respectively:

[74] This coefficient is rounded off to 12 euro cents of the non rounded-off value of €9.92/kVA.

75 This coefficient is rounded off to 12 euro cents of the non rounded-off value of €76.46/kVA.

Table 62 : BT ≤ 36 kVA tariff with 4 time categories – short use, applicable from 1 August 2021 to 31 July 2022 – power portion – collective self-production (downstream of the same HTA/BT substation)

Period of application	*b* (€/kVA/year)
from 01/08/2021 to 31/07/2022	8.40[76]

Table 63 : BT ≤ 36 kVA tariff with 4 time categories – short use, applicable from 1 August 2021 to 31 July 2022 – energy portion – collective self-production (downstream of the same HTA/BT substation)

	High season peak times *alloproduit* (j = 1)	High season off-peak times *alloproduit* (j = 2)	Low season peak times *alloproduit* (j = 3)	Low season off-peak times *alloproduit* (j = 4)	High season peak times *autoproduit* (j = 5)	High season off-peak times *autoproduit* (j = 6)	Low season peak times *autoproduit* (j = 7)	Low season off-peak times *autoproduit* (j = 8)
Energy-based coefficient (€c/kWh)	c_1 = 6.81	c_2 = 4.16	c_3 = 2.15	c_4 = 0.81	C_5 = 1.55	C_6 = 1.21	C_7 = 0.73	C_8 = 0.35

5.2.1.6.7 BT ≤ 36 tariff with four time categories – medium use - collective self-consumption (downstream of the same HTA/BT substation)

For the short-use tariff with four time categories specific to collective self-consumption (downstream of the same HTA/BT substation), the coefficients *b* and c_j to be applied from 1 August 2021 to 31 July 2022 are those of tables 64 and 65 respectively:

Table 64 : BT ≤ 36 kVA tariff with 4 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – power portion – collective self-production (downstream of the same HTA/BT substation)

Period of application	*b* (€/kVA/year)
from 01/08/2021 to 31/07/2022	9.96[77]

76 This coefficient is rounded off to 12 euro cents of the non rounded-off value of €8.42/kVA.
77 This coefficient is rounded off to 12 euro cents of the non rounded-off value of €9.96/kVA.

Table 65 : BT ≤ 36 kVA tariff with 4 time categories – medium use, applicable from 1 August 2021 to 31 July 2022 – energy portion – collective self-production (downstream of the same HTA/BT substation)

	High season peak times *alloproduit* (j = 1)	High season off-peak times *alloproduit* (j = 2)	Low season peak times *alloproduit* (j = 3)	Low season off-peak times *alloproduit* (j = 4)	High season peak times *autoproduit* (j = 5)	High season off-peak times *autoproduit* (j = 6)	Low season peak times *autoproduit* (j = 7)	Low season off-peak times *autoproduit* (j = 8)
Energy-based coefficient (€c/kWh)	c_1 = 6.21	c_2 = 3.98	c_3 = 2.09	c_4 = 0.81	C_5 = 1.55	C_6 = 1.21	C_7 = 0.73	C_8 = 0.35

5.2.1.7 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.

5.2.1.7.1 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 price list in table 66:

Table 66 : Complementary power supply component applicable from 1 August 2021 to 31 July 2022

Voltage level	Cells (€/cell/year)	Lines (€/km/year)
HTA	3,355.09	Overhead lines: 915.22 Underground lines: 1,372.83

5.2.1.7.2 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 list in table 66 above. Power subscribed for backup power supplies is less than or equal to the power subscribed 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 power 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 applicable from 1 August 2021 to 31 July 2022 is equal to the sum of the component resulting from the application of the price list in table 66 above and the component established based on the price list in table 67 below, corresponding to the pricing of the booking of transformer power:

Table 67 : Backup power supply component applicable from 1 August 2021 to 31 July 2022 – power reservation

Supply voltage level	€/kW/year or €/kVA/year
HTA	6.55
BT	6.93

If 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 supplies applicable from 1 August 2021 to 31 July 2022 is equal to the sum of the component resulting from the application of the price list in table 66 above and the component established according to the price list in table 68 below, corresponding to the pricing of the public electricity grid enabling backup in a lower voltage level.

If 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 power subscribed for each integration period of 10 minutes, the monthly component for subscribed power overruns for the backup supply is set each month according to the terms below:

$$CMDPS = \alpha * \sqrt{\sum(\Delta P^2)}$$

ΔP: designates the power overrun in kW by 10-minute interval compared to the subscribed power of the time category.

Table 68 : Backup power supply component applicable from 1 August 2021 to 31 July 2022 – pricing of the public electricity grid enabling backup

Main supply voltage level	Backup supply voltage level	Power share (€/kW/year)	Energy share (€c/kWh)	α (€c/kW)
HTB 2	HTA	8,50	1,84	68,21
HTB 1	HTA	2,96	1,84	24,22

5.2.1.8 Grouping component (CR)

A user connected to the same public network with several connection points in the same HTA 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 pricing described in section 5.2.1.4, through payment of a grouping component. In this case, the annual injection component (CI), the annual withdrawal component (CS), the monthly components for subscribed power overruns (CMDPS), and annual reactive energy component (CER) (see section 5.2.1.13) are defined based on the sum of the physical flows measured at the connection points concerned. The possibility of conventionally 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.

If conventional grouping concerns both production facilities and withdrawal points, any possible injection flows cannot be deducted from the withdrawal flows for the calculation of the annual withdrawal component.

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 system operators.

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 transit capacity available in the grids enabling this grouping. The amount of this component is calculated based on the following formula:

$$CR = l * k * P_{subscribed\ grouped}$$

$P_{subscribed\ grouped}$, designates the subscribed power for all of the points grouped conventionally

l, designates the smallest total length of electrical infrastructure in the public network concerned physically enabling grouping.

The coefficient *k* applicable from 1 August 2021 to 31 July 2022 defined in table 69 below:

Table 69 : Grouping component applicable from 1 August 2021 to 31 July 2022

Voltage level	*k* (€/kW/km/year)
HTA	Overhead lines: 0.52 Underground lines: 0.76

5.2.1.9 Specific provisions for the annual withdrawal components (CS) of public distribution system operators

For the connection points connected in the HTA voltage level, the specific provisions relating to the annual withdrawal components of public distribution system operators are specified in section 5.2.1.7 of the tariffs for the use of a public electricity network in the HTB voltage level. Within this framework, the transitional provisions specified in section 5.2.1.11 of the tariffs for the use of a public electricity network in the HTB voltage level are applicable to the calculation of the annual withdrawal component applicable to the HTB 1 voltage level.

5.2.1.10 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 request to benefit from the annual withdrawal component (CS) applicable to the voltage level directly 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 according to the following formula, depending on its subscribed power $P_{subscribed\ grouped}$.

$$CT = k * P_{Subscribed\ grouped}$$

The coefficient *k* used applicable from 1 August 20021 to 31 July 2022 is that defined in table 70 below:

Table 70 : Annual component for transformer use applicable from 1 August 2021 to 31 July 2022

Voltage level of the connection point	Voltage level of the pricing applied	k (€/kW/year)
BT	HTA	8.74

This arrangement can be combined with that of tariff grouping, according to the terms in section 5.2.1.8. In this case, pricing for the voltage level above each connection point is applied first followed by the tariff grouping mentioned above.

5.2.1.11 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 applicable to the connection point considered 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, with:

- *l1*, the total length of the line(s) operated in voltage level N by the public distribution system operator;
- l_2, the total length of the line(s) operated in voltage level N by the public distribution system operator to which they are connected and which is absolutely necessary for linking their connection point to this

operator's voltage transformer(s) required to guarantee the subscribed power in normal operating conditions defined in the reference technical documentation of the public system operator upstream;

- $CT_{N/N+1}$ is the annual component for transformer use between the voltage levels $N+1$ and N defined in section 5.2.1.10.

$$CS = \frac{l_2}{l_1 + l_2} * CS_N + \frac{l_1}{l_1 + l_2} * (CS_{N+1} + CT_{N/N+1})$$

5.2.1.12 Peak shaving in extreme cold weather

During each period of severe cold, as defined below, a distribution system operator can receive from the upstream public distribution system operator, a partial or total exoneration for its subscribed power overruns only during this period and the 24 hours after.

A period is considered as a period of severe cold when, at a local level 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 objective, transparent and non-discriminatory terms.

5.2.1.13 Annual reactive energy component (CER)

In the absence of metering systems recording physical flows of reactive energy, public system operators can provide for objective, transparent and non-discriminatory methods for estimating these flows in their reference technical documentation.

The provisions in sections 5.2.1.13.1 and 5.2.1.13.2 do not apply to the connection points located at the interface between two public electricity grids.

5.2.1.13.1 Withdrawal flows

If physical flows of active energy at a connection point are withdrawal flows, public system operators provide reactive energy free of charge:

- up to the $tg\ \varphi_{max}$ ratio defined in table 71 below, during peak times and peak times in the high season;
- without limitation outside these periods.

During these periods subject to limitation, reactive energy absorbed in the HTA voltage level and the and BT voltage level above 36 kVA beyond the $tg\ \varphi_{max}$ ratio is billed according to table 71 below:

Table 71 : Annual reactive energy component applicable from 1 August 2021 to 31 July 2022 – withdrawal flows

Voltage level	$tg\ \varphi_{max}$ ratio	€c/kVar.h
HTA	0.4	2.02
BT > 36 kVA	0.4	2.11

5.2.1.13.2 Injection flows

When the active energy physical flows at a connection point are injection flows, and the installation is not voltage controlled, the user commits to supplying or absorbing a quantity of reactive power determined by the public system operator and set depending on the active power supplied to the public system operator, based on the rules published in the reference technical documentation of the pubic distribution system operator.

In the BT voltage level, for installations with power higher than 36 kVA, the reactive energy absorbed above the $tg\ \varphi_{max}$ ratio or below the $tg\ \varphi_{min\_BT}$ ratio is billed based on table 72 below.

In the HTA voltage level, the reactive energy supplied or absorbed above the $tg\ \varphi_{max\_HTA}$ ratio or below the $tg\ \varphi_{min\_HTA}$ ratio is billed based on table 72 below.

However, below a threshold for low monthly production, the reactive energy supplied or absorbed below the $tg\ \varphi_{min\_HTA}$ ratio or above a monthly reactive energy threshold is billed according to table 72 below.

The public distribution system operator defines the low production threshold and the monthly reactive energy threshold. It determines the values of $tg\ \varphi_{max\_BT}$, $tg\ \varphi_{min\_BT}$, $tg\ \varphi_{max\_HTA}$ and $tg\ \varphi_{min\_HTA}$ of the $tg\ \varphi$ ratio thresholds by time slot.

Table 72 : Annual reactive energy component applicable from 1 August 2021 to 31 July 2022 – injection flows (installation not voltage controlled)

Voltage level	€c/kVAr.h
HTA	2.02
BT > 36 kVA	2.11

If active energy physical flows at a connection point are injection flows, and the facility is voltage controlled and the user does not benefit from a contract as provided by article L.321-12 of the energy code, the user undertakes to maintain the voltage of the facility's connection point 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 73 below 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 determined according to the rules published in the reference technical documentation of the public distribution system operator.

Table 73 : Annual reactive energy component applicable from 1 August 2021 to 31 July 2022 – injection flows (installation voltage controlled)

Voltage level	€c/kVAr.h
HTA	2.02

5.2.1.13.3 Specific provisions for the annual reactive energy component between two public electricity system operators

At each connection point shared, the public system operators agree, by contract, on the quantity of reactive energy they exchange, determined according to the active energy flows, based on the rules published in the reference technical documentation of the upstream public transmission system operator.

The reactive energy provided above the $tg\ \varphi_{max}$ ratio or absorbed below the $tg\ \varphi_{min}$ ratio is invoiced per connection point according to table 74 below.

The $tg\ \varphi_{max}$ and $tg\ \varphi_{min}$ values of the $tg\ \varphi$ ratio thresholds per connection point are agreed on by contract by time slot between public system operators. The $tg\ \varphi_{max}$ value in the contract is lower than 0.4 and takes into account, by default, the historical values of the $tg\ \varphi$ observed.

Table 74 : Annual reactive energy component between two public electricity system operators applicable from 1 August 2021 to 31 July 2022

Voltage level	€c/kVAr.h
HTA	2.02

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 networks.

5.2.1.14 Transitional provisions for the implementation of the present tariff rules

Users connected in the BT voltage level with subscribed power lower than or equal to 36 kVA (or third parties authorised by them) can, in the six months following the initial communication of a smart meter, recently installed, with the DSO's information system, modify on one occasion their option and tariff version for the connection point concerned without having to comply with the period of 12 consecutive months since their previous tariff option choice.

HTA and BT users can, in the six months following the entry into effect of the present deliberation, modify on one occasion their option and tariff version for the connection point concerned without having to comply with the period of 12 consecutive months since their previous tariff option choice.

5.2.2 Tariffs applicable in 2022, 2023, 2024

5.2.2.1 Change in tariff coefficients (excluding R_f and C_{card} parameters)

Each year N as from 2022, the tariff coefficients, excluding the R_f and C_{card} parameters and the coefficients for the withdrawal 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 is defined as follows, rounded off to four decimal points (0.0001):

$$Y_N = Y_{N-1} \times (1 + Z_N)$$

The annual update coefficient of year *N* is defined as:

$$Z_N = IPC_N + K_N + X$$

- Z_N: the annual update coefficient as at 1 August of year N, rounded off to the nearest one hundredth percent;
- IPC_N: forecast inflation rate for year *N* taken into account in the finance law of year *N*;
- K_N: updated coefficient produced 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 0.31%.

5.2.2.2 Reference tariffs applicable for the years 2022, 2023 and 2024

5.2.2.2.1 Reference tariffs for the HTA voltage level

HTA tariff with 4 time categories – applicable as at 1 August 2021	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	4.88	4.67	4.40	4.26	3.60
Long use €/kW	19.36	18.26	13.85	9.71	4.15
Short use €c/kWh	3.73	3.20	2.17	1.64	1.01
Long use €c/kWh	2.80	2.11	1.38	0.89	0.77

HTA tariff with mobile peak times and 4 time categories – applicable as at 1 August 2021	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	5.34	4.61	4.40	4.26	3.60
Long use €/kW	21.81	19.93	13.85	9.71	4.15
Short use €c/kWh	4.78	3.07	2.17	1.64	1.01
Long use €c/kWh	3.21	1.93	1.38	0.89	0.77

HTA tariff with 4 time categories – 2022 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	7.09	6.95	6.76	6.67	6.23
Long use €/kW	22.25	20.61	14.28	10.59	6.61
Short use €c/kWh	4.32	3.44	2.21	1.32	0.82
Long use €c/kWh	2.72	2.06	1.42	0.78	0.66

HTA tariff with mobile peak times and 4 time categories – 2022 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	7.39	6.90	6.76	6.67	6.23
Long use €/kW	24.69	22.27	14.28	10.59	6.61
Short use €c/kWh	5.37	3.31	2.21	1.32	0.82
Long use €c/kWh	3.14	1.88	1.42	0.78	0.66

HTA tariff with 4 time categories – 2023 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	9.29	9.22	9.13	9.08	8.86
Long use €/kW	25.15	22.96	14.70	11.47	9.08
Short use €c/kWh	4.91	3.68	2.25	0.99	0.64
Long use €c/kWh	2.64	2.01	1.45	0.68	0.54

HTA tariff with mobile peak times and 4 time categories – 2023 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	9.44	9.20	9.13	9.08	8.86
Long use €/kW	27.58	24.61	14.70	11.47	9.08
Short use €c/kWh	5.96	3.55	2.25	0.99	0.64
Long use €c/kWh	3.06	1.83	1.45	0.68	0.54

HTA tariff with 4 time categories – 2024 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	11.49	11.49	11.49	11.49	11.49
Long use €/kW	28.04	25.31	15.14	12.35	11.54
Short use €c/kWh	5.50	3.94	2.30	0.67	0.44
Long use €c/kWh	2.57	1.96	1.49	0.57	0.43

HTA tariff with mobile peak times and 4 time categories – 2024 reference	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	11.49	11.49	11.49	11.49	11.49
Long use €/kW	30.47	26.96	15.14	12.35	11.54
Short use €c/kWh	6.55	3.79	2.30	0.67	0.44
Long use €c/kWh	2.98	1.78	1.49	0.57	0.43

5.2.2.2.2 Reference tariffs for the BT > 36 kVA voltage level

BT > 36 kVA tariff with 4 time categories – applicable as at 1 August 2021	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	11.61	7.11	5.90	3.74
Long use €/kW	20.57	12.51	10.48	5.95
Short use €c/kWh	5.15	3.36	2.28	1.80
Long use €c/kWh	4.43	3.11	2.00	1.70

BT > 36 kVA tariff, self-consumption with 4 time categories – applicable as at 1 August 2021	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	11.67	6.87	5.34	3.40
Long use €/kVA	21.05	12.82	9.95	5.84
Short use €c/kWh *alloproduit*	5.24	2.88	2.06	1.81
Long use €c/kWh *alloproduit*	4.57	2.68	1.84	1.27
Short use €c/kWh *autoproduit*	2.93	1.78	0.76	0.56
Long use €c/kWh *autoproduit*	2.93	1.78	0.76	0.56

BT > 36 kVA tariff with 4 time categories – 2022 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	12.54	8.74	7.81	6.26
Long use €/kW	21.55	13.35	11.41	7.94
Short use €c/kWh	5.16	3.56	2.23	1.69
Long use €c/kWh	4.40	3.22	1.99	1.54

BT > 36 kVA tariff, self-consumption with 4 time categories – 2022 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	12.61	8.44	7.07	5.71
Long use €/kVA	22.06	13.68	10.83	7.79
Short use €c/kWh *alloproduit*	5.25	3.06	2.01	1.69
Long use €c/kWh *alloproduit*	4.54	2.77	1.83	1.15
Short use €c/kWh *autoproduit*	2.94	1.89	0.74	0.52
Long use €c/kWh *autoproduit*	2.94	1.89	0.74	0.52

BT > 36 kVA tariff with 4 time categories – 2023 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	13.47	10.37	9.72	8.79
Long use €/kW	22.54	14.19	12.34	9.93
Short use €c/kWh	5.17	3.77	2.18	1.58
Long use €c/kWh	4.37	3.33	1.98	1.38

BT > 36 kVA tariff, self-consumption with 4 time categories – 2023 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	13.55	10.02	8.79	8.01
Long use €/kVA	23.06	14.55	11.71	9.73
Short use €c/kWh *alloproduit*	5.26	3.24	1.96	1.58
Long use €c/kWh *alloproduit*	4.50	2.87	1.82	1.03
Short use €c/kWh *autoproduit*	2.94	2.00	0.72	0.49
Long use €c/kWh *autoproduit*	2.94	2.00	0.72	0.49

BT > 36 kVA tariff with 4 time categories – 2024 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kW	14.40	12.00	11.63	11.32
Long use €/kW	23.52	15.03	13.26	11.91
Short use €c/kWh	5.18	3.97	2.13	1.47
Long use €c/kWh	4.33	3.44	1.97	1.21

BT > 36 kVA tariff, self-consumption with 4 time categories – 2024 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	14.48	11.59	10.52	10.31
Long use €/kVA	24.07	15.41	12.59	11.68
Short use €c/kWh *alloproduit*	5.27	3.42	1.92	1.47
Long use €c/kWh *alloproduit*	4.47	2.96	1.81	0.91
Short use €c/kWh *autoproduit*	2.95	2.11	0.71	0.45
Long use €c/kWh *autoproduit*	2.95	2.11	0.71	0.45

5.2.2.2.3 Reference tariffs for the BT ≤ 36 kVA voltage level

BT ≤ 36 kVA tariff without time differentiation – applicable as at 1 August 2021	
Short use €/kVA	8.52
Long use €/kVA	76.44
Short use €c/kWh	3.71
Long use €c/kWh	1.04

BT ≤ 36 kVA tariff with 2 time categories – applicable as at 1 August 2021	Peak times	Off-peak times
Medium use €/kVA	10.32	
Medium use €c/kWh	3.79	2.68

BT ≤ 36 kVA tariff with 4 time categories – applicable as at 1 August 2021	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.40			
Medium use €/kVA	9.96			
Short use €c/kWh	6.27	4.29	1.34	0.83
Medium use €c/kWh	5.75	3.99	1.31	0.82

BT ≤ 36 kVA tariff, self-consumption with 4 time categories – applicable as at 1 August 2021	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.40			
Medium use €/kVA	9.96			
Short use €c/kWh *alloproduit*	6.81	4.16	2.15	0.81
Medium use €c/kWh *alloproduit*	6.21	3.98	2.09	0.81
Short use €c/kWh *autoproduit*	1.55	1.21	0.73	0.35
Medium use €c/kWh *autoproduit*	1.55	1.21	0.73	0.35

BT ≤ 36 kVA tariff without time differentiation – 2022 reference	
Short use €/kVA	8.80
Long use €/kVA	75.36
Short use €c/kWh	3.85
Long use €c/kWh	1.02

BT ≤ 36 kVA tariff with 2 time categories – 2022 reference	Peak times	Off-peak times
Medium use €/kVA	10.74	
Medium use €c/kWh	3.93	2.78

BT ≤ 36 kVA tariff with 4 time categories – 2022 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.31			
Medium use €/kVA	9.78			
Short use €c/kWh	6.18	4.23	1.32	0.82
Medium use €c/kWh	5.67	3.93	1.29	0.81

BT ≤ 36 kVA tariff, self-consumption with 4 time categories – 2022 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.32			
Medium use €/kVA	9.83			
Short use €c/kWh *alloproduit*	6.71	4.10	2.12	0.80
Medium use €c/kWh *alloproduit*	6.12	3.92	2.06	0.80
Short use €c/kWh *autoproduit*	1.53	1.19	0.72	0.35
Medium use €c/kWh *autoproduit*	1.53	1.19	0.72	0.35

BT ≤ 36 kVA tariff without time differentiation – 2023 reference	
Short use €/kVA	9.18
Long use €/kVA	74.63
Short use €c/kWh	4.01
Long use €c/kWh	1.01

BT ≤ 36 kVA tariff with 2 time categories – 2023 reference	Peak times	Off-peak times
Medium use €/kVA	11.19	
Medium use €c/kWh	4.10	2.90

BT ≤ 36 kVA tariff with 4 time categories – 2023 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.24			
Medium use €/kVA	9.69			
Short use €c/kWh	6.12	4.19	1.31	0.81
Medium use €c/kWh	5.62	3.89	1.28	0.80

BT ≤ 36 kVA tariff, self-consumption with 4 time categories – 2023 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.25			
Medium use €/kVA	9.76			
Short use €c/kWh *alloproduit*	6.64	4.06	2.10	0.79
Medium use €c/kWh *alloproduit*	6.06	3.88	2.04	0.79
Short use €c/kWh *autoproduit*	1.51	1.18	0.71	0.34
Medium use €c/kWh *autoproduit*	1.51	1.18	0.71	0.34

For the BT ≤ 36 kVA voltage level in 2024, only the options with four time categories can be subscribed. The options without time differentiation (Basic) and with two time categories (peak times/off-peak times) can only be subscribed, by way of derogation, for clients not equipped with a smart meter, and the reference tariff is then equal to that of 2023.

BT ≤ 36 kVA tariff without time differentiation – 2024 reference	
Short use €/kVA	9.18
Long use €/kVA	74.40
Short use €c/kWh	4.01
Long use €c/kWh	1.01

BT ≤ 36 kVA tariff with 2 time categories – 2024 reference	Peak times	Off-peak times
Medium use €/kVA	11.19	
Medium use €c/kWh	4.10	2.90

BT ≤ 36 kVA tariff with 4 time categories – 2024 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.21			
Medium use €/kVA	9.66			
Short use €c/kWh	6.10	4.17	1.30	0.81
Medium use €c/kWh	5.60	3.88	1.28	0.80

BT ≤ 36 kVA tariff, self-consumption with 4 time categories – 2024 reference	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
Short use €/kVA	8.24			
Medium use €/kVA	9.74			
Short use €c/kWh *alloproduit*	6.62	4.05	2.09	0.79
Medium use €c/kWh *alloproduit*	6.03	3.86	2.03	0.79
Short use €c/kWh *autoproduit*	1.51	1.17	0.71	0.34
Medium use €c/kWh *autoproduit*	1.51	1.17	0.71	0.34

5.2.3 Change in the R_f and C_{card} parameters as from 1 August 2021

5.2.2.3 Change in the R_f parameter as from 1 August 2021

The R_f parameter is updated taking into account the values and methods for updating the grid access component paid to suppliers defined by CRE's deliberation no. 2018-011 of 18 January 2018[78].

On an indicative basis, the deliberation of 18 January 2018 in effect, fixes, for the component for access to the public electricity distribution grids for the management of clients under a single contract, the following levels:

- €156 per year for HTA customers;
- €78 per year for BT > 36 kVA customers
- for BT ≤ 36 kVA customers, the pubic electricity grid access component changes as at 1 August of each year specifically for connection points under the regulated sales tariff (TRV), until 1 August 2022. On the occasion of the annual tariff update, the R_f parameter changes to take into account the evolution in the portion of clients under market offers and under TRV, and based on the average estimated costs by category of clients.

[78] CRE's deliberation no. 2018-011 of 18 January 2018 deciding on the component for access to the public electricity distribution grids for the management of clients with a single contract in the HTA and BT voltage levels.

5.2.2.4 Change in the C_{card} parameter as from 1 August 2021

The value of the C_{card} parameter used in the calculation of the management component billed to users having entered into a grid access agreement themselves is based on the reference values defined in the following table:

Table 75 : Reference value of the C_{CARD} parameter by voltage level and connection power

Voltage level and connection power	Reference value of the C_{card} parameter (€/year)
HTA	212.00
BT > 36 kVA	106.00
BT ≤ 36 kVA	7.90

As from 1 August 2021, the amount of the C_{card} parameter applicable for the period from 01/07/N to 30/06/N+1 is obtained by indexation of this reference value to the inflation effectively observed and cumulated between 2019 and N-1.

ANNEX 1 – AMOUNTS TO BE INTEGRATED WITHIN THE SCOPE OF REGULATED EQUITY AS AT 1 JANUARY IN ACCORDANCE WITH THE DECISION BY THE STATE COUNCIL

In €million$_{nominal}$

2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
1,598	1,564	1,527	1,488	1,447	1,405	1,362	1,317	1,272	1,225

2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
1,178	1,130	1,081	1,032	982	929	875	817	760	702

2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
645	588	532	475	418	362	306	250	194	146

2048	2049	2050	2051	2052	2053	2054	2055	2056	2057
111	93	82	73	64	56	48	42	36	31

2058	2059	2060	2061	2062	2063	2064	2065	2066	2067
27	22	19	16	13	10	8	6	5	3

2068	2069	2070	2071	2072	2073
2	1	1	0[79]	0[80]	0[81]

[79] Amount lower than €0.5 million
[80] Amount lower than €0.5 million
[81] Amount lower than €0.5 million

ANNEX 2 - REFERENCES FOR THE ANNUAL UPDATE OF THE TARIFFS FOR THE USE OF THE PUBLIC ELECTRICITY GRIDS AS FROM 1 AUGUST 2022

1. Calculation and reconciliation of the CRCP

Enedis's CRCP balance, as at 1 January 2021, is equal to the difference between the definitive amount of the CRCP balance of TURPE 5 HTA-BT and the provisional amount, equal to €588 million, taken into account to prepare TURPE 6 HTA-BT.

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 tariff update in TURPE HTB between 1 August 2021 and 1 August of year N, and the forecast revenues calculated using the assumptions about the quantities distributed and the number of consumers served adopted in the present deliberation*,* re-evaluated based on actual changes already applied to the tariff;
- and the difference, for year *N*, between:
    - o the difference between the definitive allowed revenue, as defined hereafter, and the forecast allowed revenue adjusted for inflation and the tariff update of TURPE HTB between 1 August 2021 and 1 August of year N;
    - o the difference between the revenues received by Enedis and the forecast 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 definitive 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 from the incentive regulation concerning research and development (R&D) 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;
    - normative capital expenses not giving rise to incentives;
    - expenses related to the TURPE HTB payment for Enedis's distribution substations;
    - expenses related to the connection of distribution substations to the public transmission grid;
    - expenses relating to power losses and the incentive regulation for power losses;
    - expenses related to arrears of end clients corresponding to TURPE;
    - expenses related to Enedis's contributions to the FPE, only for the portion of these expenses resulting from the application of the accounting method to LDCs that so request it;
    - net expenses relating to the contribution paid to suppliers for the management of clients under a single contract;
    - stranded costs (net book value of demolished assets);
    - concession fees for the variations due to the number of contracts renewed by Enedis;
    - expenses associated with implementation of flexibility;

    - operating expenses associated with the restoration of the grid following weather hazards;
    - the amounts adopted for the mechanism for taking into account smart grid industrial deployment projects (smart grid counter), 100% covered;
    - 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:
    - contributions from users received for connection;
    - revenues associated with the gains made from the disposal of real estate or land assets;
    - differences in revenues related to unplanned changes in the rates for ancillary services;
    - the amounts determined by CRE as part of taking into account contracts signed by the EDF group with third parties concerning smart metering;
- and to which is added the sum of the amounts adopted for financial incentives as part of:
    - incentive regulation for unit costs of investments in the networks;
    - incentive regulation specific to the Linky smart metering project;
    - the incentive regulation for continuity of supply;
    - incentive regulation for quality of service;
    - incentive regulation for the provision of data;
    - incentive regulation for supporting external innovation;
    - for the year 2024, the amounts adopted for incentive regulation for research and development (R&D) expenses, where applicable, are deducted from allowed revenue;
- to which is added the reconciliation of the forecast CRCP balance of TURPE 5
- and from which is deducted the amounts attributed to the smoothing regulatory account for the Linky project for 2021 and 2022 and to which is added the amounts reconciled for 2023 and 2024.

For each item, the method for calculating the amount adopted is presented in detail below.

i. Expense items taken into account to calculate the definitive allowed revenue

a) Forecast net incentive-backed operating expenses

Forecast net incentive-backed operating expenses correspond to net operating expenses excluding expenses related to the electricity system taken into account for TURPE 6, with the exception of connection contributions, expenses relating to Enedis's contributions to the FPE for the portion determined by application of the account analysis method, concession fees and arrears. The amounts adopted are the reference amounts presented hereafter, corrected for actual inflation.

The reference values for forecast net incentive-backed operating expenses are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for forecast net incentive-backed operating expenses	4,717	4,677	4,660	4,718

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*[82]	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 1763852), 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 hereafter of normative capital expenses related to "vehicles", "real estate" and "information systems" assets with the exception of the IS projects excluded from the scope of incentive regulation, specified in annex 5.

Forecast values for "non-grid" incentive-backed normative capital expenses are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for "non-grid" incentive-backed normative capital expenses	314	341	377	364

c) Normative capital expenses not giving rise to incentives

The amount adopted for the calculation of the definitive allowed revenue is equal to capital expenses, with the exception of those taken into account in the "non-grid" incentive-backed capital expenses. These capital expenses are calculated based on the investments effectively made, asset removals, liability items in Enedis's accounts and Enedis's depreciation and renewal provisions. These capital expenses take into account the adjustment trajectories relating to the integration of ELAN electrical risers specified in annex 9.

On an indicative basis, the forecast values for these capital expenses are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for normative capital expenses not giving rise to incentives	4,392	4,496	4,592	4,696

d) Expenses related to Enedis's payment of TURPE HTB for the distribution substations

The amount adopted for the calculation of the definitive allowed revenue is equal to the expenses related to the payment of TURPE HTB by Enedis.

On an indicative basis, the forecast values for these expenses related to the TURPE HTB payment are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for expenses related to Enedis's TURPE HTB payment for the distribution substations	3,617	3,646	3,691	3,746

e) Expenses related to the connection of distribution substations to the public transmission grid

The amount adopted for the calculation of the definitive allowed revenue is equal to Enedis's expenses related to the connection of distribution substations to the public transmission grid.

On an indicative basis, the forecast values for these expenses related to the connection of distribution substations to the public transmission grid are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for expenses related to the connection of distribution substations to the public transmission grid	36	42	33	23

f) Expenses related to power losses

[82] 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 inflation mentioned in section 3.1.2.2 of the present deliberation.

As from the year 2021, for a given year *N*, the annual incentive relating to the compensation of power losses corresponds to 20% of the difference between the reference annual amount P_N and the actual expenses borne by Enedis, for power losses compensation of year *N*. It is capped at +/-€40 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 power losses compensation effectively borne by Enedis during year *N*;

On an indicative basis, the forecast values for these purchase costs for power losses compensation, excluding incentive regulation, are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for expenses relating to power losses compensation	1 202	1 181	1 165	1 159

- the amount of annual incentive for year *N-1*, calculated based on the provisional data available;
- for year *N-2* (or a previous year), 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.

Given the method for calculating the incentive for the incentive regulation for power losses (based on the purchases made for years *N-1* and *N-2*), the calculation of the incentive for the year 2022 (covering years 2020 and 2021) will use, for the calculation of the incentive for the year 2020 (definitive data) the parameters presented in the TURPE 5 deliberation; for the calculation of the incentive for the year 2021 (provisional data) the parameters presented in the TURPE 6 deliberation.

The reference annual amount for the power losses of year *N*, P_N, is calculated according to the following formula:

$$P_N = V_N * PU_N$$

Where:

- V_N is the reference annual volume of year *N*, in MWh;
- PU_N is the reference unit price of year *N*, in €/MWh.

Reference annual volume V_N

CRE has changed the method for calculating the reference volume compared to TURPE 5. The method implemented by CRE is based on the calculation of two reference volumes:

- one for non-technical power losses V_{N_PNT} (roughly 45% of total losses);
- one for technical power losses V_{N_PT} (roughly 55% of total losses).

The sum of the two volumes is used to define Enedis's reference volume V_N for year N.

The reference volume for non-technical power losses (V_{N_PNT}) is calculated through a reference rate applied to gross annual consumption (C_{Brut_N}) in Enedis's network. The reference rate adopted is as follows:

	2021	2022	2023	2024
Reference rate for non-technical power losses	2.9%	2.8%	2.6%	2.5%

For the calculation of the reference volume of technical power losses (V_{N_PT}), CRE maintains a polynomial-type formula which corresponds to Enedis's current model for technical power losses.

Technical polynomials are second degree polynomials calculated with the following equation. $P = aX^2+bX+c$.
There are three modelling levels: Distribution substation (PS), HTA network, BT network
The coefficients associated with each polynomial are as follows:

Coefficients	PS	HTA	BT

a	3,52E-11	1,44E-10	6,73E-10
b	9,32E-04	7,40E-04	- 8,06E-03
c	9,97E+04	1,40E+04	5,58E+05

The definition of the variable X by voltage level is as follows:

- Distribution substation: X is defined as the sum:
  - of injections coming from RTE's distribution substations;
  - backfeed to RTE's network.
- HTA: X is defined as the sum:
  - of injections coming from RTE's distribution substations;
  - backfeed to RTE's network;
  - injections coming from the networks of LDCs connected to Enedis's network;
  - from which are subtracted the distribution substation power losses calculated in the previous point.
- BT: X is defined as the total injections in Enedis's networks (injections coming from the networks of RTE and of LDCs connected to Enedis as well as from production sources connected to Enedis's network) from which are subtracted:
  - backfeed to RTE's network;
  - withdrawals from LDCs connected to Enedis's network;
  - consumption of profile-based HTA clients;
  - consumption of HTA clients with load curves;
  - distribution substation power losses calculated in the previous point;
  - HTA power losses calculated in the previous point.

Reference unit price PU_N

The reference unit price of power 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 power losses on an hourly basis. This load curve corresponds to Enedis's power losses load curve adopted for the "Recotemp" and "Recoflux" processes.

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 ARENH prices, 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* and weekly 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 phenomena.

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.

g) Expenses related to end client arrears corresponding to TURPE payment

The amount adopted for the calculation of the definitive allowed revenue is equal to the sum of expenses and revenues of year *N* for the handling by Enedis of arrears for the portion corresponding to the TURPE payment, covering consumption prior to 1 January 2016 for customers benefiting from market offers or regulated sales tariffs.

On an indicative basis, the forecast values for end client arrears corresponding to the TURPE payment are as follows:

In nominal €million	2021	2022	2023	2024
Forecast values for end client arrears corresponding to the TURPE payment	90	90	90	90

h) Expenses related to Enedis's contributions to the FPE by the accounts analysis method

The amount adopted for the calculation of the definitive allowed revenue is equal to the sum of contributions by Enedis year *N* to the electricity equalisation fund for the portion of contributions falling within the application of the accounts analysis method. These contributions include payments determined by CRE based on the costs incurred, for all DSOs serving more than 100,000 clients or performing their activity in a non-interconnected zone so requesting it.

On an indicative basis, the forecast values for these contributions by Enedis to the FPE, excluding contributions calculated by application of the normative method, are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for the contributions by Enedis to the FPE for the portion due to application of the accounts analysis method	240	240	240	240

i) Expenses relating to the contribution paid to suppliers for the management of clients under a single contract

The amount adopted for the calculation of the definitive allowed revenue is equal to the sum of the contributions paid to suppliers by Enedis for the management of clients under a single contract. The amount taken into account for year N corresponds to the contributions paid year N for the management of clients under a single contract within the limit of the maximum amounts set out by deliberation no.2018-011 of 18 January 2018, for each connection point, to which are added, if applicable, interest expenses.

For the DSO's expenses resulting from payments to suppliers made after 1 January 2021, but for the management of clients under a single contract ensured by them prior to 1 January 2018, the maximum amount by connection point that can be taken into account in the CRCP mechanism is defined by deliberation no.2017-239 of 26 October 2017.

The forecast values for these expenses relating to the contribution paid to suppliers for the management of clients under a single contract are zero.

j) Expenses related to stranded costs

In compliance with the provisions specified in section 2.1.2.4.1, stranded costs deemed recurrent or foreseeable are subject to a trajectory included in the incentive-backed operating expenses. The average annual amount taken into account totals €68 million/year.

CRCP coverage of stranded costs, apart from those deemed recurring and foreseeable, which are withdrawn from inventory before the end of their useful life, are examined by CRE, based on reasoned requests presented by Enedis.

The annual reference amount taken into account for the calculation of the final allowed revenue corresponds to the expenses that will actually be adopted following this examination.

The forecast values for the expenses related to non-recurring or foreseeable stranded costs are zero.

k) Expenses related to concession fees

The amount adopted for the calculation of the definitive allowed revenue is equal to the trajectory of forecast costs, corrected for any changes in the contract renewal pace. The detailed conditions for the calculation of this corrected trajectory are described in a confidential annex.

On an indicative basis, the forecast amounts of expenses related to concession fees are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for expenses related to concession fees	321	323	328	331

l) Expenses related to the implementation of flexibility

The amount adopted for the calculation of the definitive allowed revenue is equal to the sum of the operating expenses generated by the use of flexibility solutions, validated after CRE's analysis, in Enedis's network.

The forecast values for these expenses related to the implementation of flexibility are zero.

m) Operating expenses associated with the restoration of the grid following weather hazards

The amount adopted for the calculation of the definitive allowed revenue is equal to the difference between the amount of expenses incurred corresponding to additional work and labour purchases associated with weather hazards and the trajectory of €40 million/year set for this item, for only the portion of this amount higher or lower than €20 million.

Given the expiry date of Enedis's storm insurance coverage contract, any proceeds associated with the payment to Enedis of compensation by its insurance policy in the case of an exceptional event occurring in the first half of 2021 would be adopted in the calculation of the definitive allowed revenue.

The forecast values for these operating expenses associated with the restoration of the grid following weather hazards are zero.

n) Inclusion of smart grid industrial deployment projects

Enedis may request, once per year, for inclusion upon the annual update of TURPE, the integration of additional operating costs or incentive-backed normative capital expenses associated with 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 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 expenses as well as the associated incentive amounts adopted in that regard in the calculation of the definitive allowed revenue are determined by CRE.

o) 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:

In nominal €million	2021	2022	2023	2024
Annual differences between forecast revenues and allowed revenue	*-41*	*-188*	*34*	*204*

ii. Revenue items used for the calculation of the definitive allowed revenue

a) Contributions from users received for connection

The amount adopted for the calculation of the definitive allowed revenue is equal to the revenues effectively received by Enedis for year *N* as contributions for connection.

On an indicative basis, the forecast values for these contributions by users received for connection are as follows:

In nominal €million	2021	2022	2023	2024
Reference value for contributions from users received for connection	- 755	- 760	- 821	- 920

b) Profits from the disposal of land or buildings

The reference amount taken into account for the calculation of the definitive allowed revenue corresponds to 80% of the proceeds from the disposal, net of the net book value of the asset sold.

c) Differences in revenues related to unplanned changes in the rates for ancillary services

The amount adopted for the calculation of the definitive allowed revenue is the difference between:

- revenues effectively received by Enedis for year *N* for ancillary services whose tariff evolution is different to that resulting from the application of annual indexation formulas to the tariffs specified by the deliberation of 25 June 2019 deciding on the ancillary services performed exclusively by electricity distribution system operators;
- the revenues that Enedis would have received for year *N* for these same services if the tariff applied had been that resulting from the application of annual indexation formulas to the tariffs specified by the deliberation of 25 June 2019 deciding on the ancillary services performed exclusively by electricity distribution system operators.

d) Consideration of contracts signed by the EDF group with third parties relating to smart metering

CRE requests Enedis to communicate to it any new contract relating to smart metering which is signed between the EDF group and third parties during the TURPE 6 period.

If the resulting revenues are significant, the matter of sharing them between grid users and Enedis could be raised. CRE could take into account in TURPE 6, partly or fully, the financial consequences resulting from such contracts.

The amounts adopted for the calculation of the definitive allowed revenue are those defined by CRE, if applicable, under such a sharing scheme.

iii. Financial incentives under the incentive regulation

a) Incentive regulation for unit costs of investments in the networks

The investments concerned by the incentive regulation mechanism are grouped into 24 categories defining the six types of infrastructure below:

- underground HTA infrastructure;
- underground BT infrastructure;
- overhead BT infrastructure;
- customer dry connections ≤ 36 kVA;
- producer dry connections ≤ 36 kVA;
- prefabricated HTA/BT transformer substations;

as well as the four urban density zones below:

- zone 1: towns with fewer than 10,000 inhabitants;

- zone 2: towns with 10,000 to 100,000 inhabitants;
- zone 3: towns with over 100,000 inhabitants excluding cities with more than 100,000 inhabitants and Paris suburbs;
- zone 4: cities with more than 100,000 inhabitants and Paris suburbs.

Within each of these categories, the cost of each investment is modelled by:

- a fixed portion B_i (which depends on the infrastructure category *i* but not on the year of commissioning);
- if applicable (for HTA and BT infrastructure), a variable portion depending on the length of the infrastructure concerned A_i (which depends on the infrastructure category *i* but not on the year of commissioning);
- for connections, an average annual update coefficient for the unit costs of connections CB_N (which depends on the year *N* considered but not on the type of connection);
- for the prefabricated HTA/BT transformer substations, an average annual update coefficient for the unit costs of substations CP_N (which depends on the year *N* considered);
- for the other network infrastructure, an average annual update coefficient for the unit costs of network infrastructure CR_N (which depends on the year *N* considered but not on the type of infrastructure).

The values of these parameters are determined, in particular, based on the costs of investments brought into service between 2016 and 2019. These values and the target annual coefficients for the average change in unit costs over the 2021-2024 are defined in a confidential annex to this document.

For a given year *N*, the total modelled cost of investments is calculated using the volume of actual investments made, and the annual incentive corresponds to 20% of the difference between the real total cost of the infrastructure commissioned year *N* and the total modelled cost of this same infrastructure. It is capped at +/- €30 million per year.

The annual incentive is first calculated based on provisional data, and the following year 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:

- the amount of the annual incentive for year *N-1*, calculated based on the provisional data available;
- the difference between the annual incentive amount for year *N-2*, calculated based on the updated data and that of this same incentive calculated the previous year based on provisional data.

Given the method for calculating the incentive on unit costs of investments in the networks (based on the investments of years *N-1* and *N-2*), the calculation of the incentive for years 2021 and 2022 will be based, in part, on investments made in 2019 and 2020. For these two years, the calculations of incentives on the unit costs of investments to which they are associated will be done based on the parameters described in the TURPE 5 deliberation.

b) Incentive regulation specific to Enedis' smart metering project

The reference amount used for the calculation of the definitive allowed revenue is equal to the sum, for the year in question, of the financial incentives related to the "Linky" smart metering project, as defined by CRE's deliberation of 23 July 2020 deciding on the incentive regulation framework for Enedis's smart metering system[83].

c) Incentive regulation for continuity of supply

A follow-up of continuity of supply is established for Enedis, LDCs serving more than 100,000 clients and EDF SEI. This follow-up comprises indicators transmitted regularly by the DSOs to CRE. All of the follow-up indicators for continuity of supply set up for the DSOs must be published on their respective websites.

The lists of indicators relating to the DSOs' continuity of supply defined for TURPE 6, including the penalty mechanism for long outages, are contained in annex 7 of the present deliberation.

Enedis's indicators relating to annual average durations and frequencies of outages for users connected in the BT and HTA ranges are subject to financial incentives. The objectives and amounts of bonuses and penalties for indicators subject to financial incentives calculated annually will apply as from 1 January 2021.

The mechanism for following DSOs' continuity of supply may be submitted to any audit deemed useful by CRE.

[83] Deliberation by the French Energy Regulatory Commission no. 2020-013 of 23 January 2020 deciding on the incentive regulation framework for Enedis's smart metering system in the BT ≤ 36 kVA voltage level (Linky) for the 2020-2021 period

The amount adopted for the calculation of Enedis's definitive allowed revenue, for the incentive regulation for continuity of supply, is equal to the sum:

- within the overall limit of ±€83 million, of the sum of the four financial incentives defined in section 3.1 of annex 7 for the year in question;
- of the cumulated amount paid by Enedis the year in question to users under the penalty mechanism for long outages defined in section 2 of annex 7, only for the portion of this amount exceeding, as the case may be, the level of €117 million (when the cumulated amount is lower than €117 million, no amount is therefore taken into account).

d) Incentive regulation for quality of service

A follow-up of quality of service is established for Enedis, the LDCs serving more than 100,000 clients and EDF SEI in the key areas of the operators' activity. This follow-up comprises indicators transmitted regularly by the DSOs to CRE. All of the follow-up indicators for quality of service set up for the DSOs must be published on their websites.

Some indicators, concerning areas that are most important for the proper functioning of the market, are subject to a financial incentive system. The objectives and amounts of bonuses and penalties for indicators subject to financial incentives calculated annually will apply as from the year 2021. CRE may, as needs be, introduce new financial incentives, depending on the evolution of performance observed regarding quality of service.

The quality of service follow-up indicators sent by Enedis to CRE must be certified by an external body. Moreover, the DSOs' quality of service follow-up mechanism may be subject to any audit that CRE deems useful.

The lists of the quality of service indicators of Enedis, LDCs serving more than 100,000 clients and EDF SEI defined for TURPE 5 HTA-BT are contained in annex 6 of the present deliberation.

The amount adopted for the calculation of Enedis's definitive allowed revenue, under incentive regulation for quality of service, is equal to the sum of the financial incentives defined in section 1.1 of annex 6.

e) Incentive regulation for the provision of data

A follow-up of Enedis's quality of data and compliance with deadlines for their provision is introduced by the present deliberation. This follow-up comprises indicators transmitted regularly by Enedis to CRE. All of the follow-up indicators on the quality of data or the deadlines for their provision, must be published on Enedis's website.

The list of follow-up indicators relating to provision of data is contained in section 8 of the present deliberation.

Some indicators are subject to a financial incentive system. The objectives and amounts of bonuses and penalties for indicators subject to financial incentives calculated annually will apply as from the year 2021. CRE may, as needs be, introduce new financial incentives, depending on the evolution of performance observed. The mechanism for following the quality of 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 sum of the financial incentives defined in section 1.1 of annex 8.

f) Incentive regulation for supporting external innovation

The present deliberation introduces a financial incentive mechanism for compliance by Enedis with the implementation deadlines for actions identified as priorities for promoting innovation in market participants (described in section 2.5.4 of the present deliberation). No action is integrated as of the implementation of this mechanism in TURPE 6 HTA-BT.

CRE may introduce, during TURPE 6 HTA-BT, 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*.

g) Incentive regulation for research and development (R&D) expenses

The reference amounts for R&D expenses (including expenses related to smart grids projects) taken into account to prepare TURPE 6 are as follows:

In nominal €million	2021	2022	2023	2024
Reference amount for R&D expenses subject to incentive regulation	56	56	57	58

The possibility exists for this reference trajectory to be revised mid-period.

If the total R&D expenses amount (including spending related to smart grids projects) incurred over the 2021-2024 period is lower than the cumulated reference amounts used to define the TURPE 6 tariff, the difference will be taken into account in the CRCP balance at the end of the tariff period.

Transparency and verification of the efficiency of spending associated with R&D&I 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 subject to any audit deemed useful by CRE.

iv. Reconciliation of the forecast CRCP balance of TURPE 5

The reference amount taken into account for reconciliation of the forecast CRCP balance for TURPE 5 is as follows:

In nominal €million	2021	2022	2023	2024
Reconciliation of the forecast CRCP balance of TURPE 5	153	153	153	153

v. Consideration of the smoothing regulatory account associated with the Linky project

CRE's deliberation of 17 July 2014 defining the regulatory framework applicable to Enedis's smart metering project[84] established a mechanism for delaying, until the theoretical end of the massive deployment of smart meters, the effects of the Linky project on operating and capital expenses (depreciation and remuneration of capital invested). During this delay, the effects are recorded in a smoothing regulatory account (CRL). The amounts recorded each year in the CRL were established *ex ante* based on the business plan communicated by Enedis for its smart metering project and enables neutralisation over the 2014 to 2021 period of the forecast impacts of the project on Enedis's operating and capital expenses. The year 2022 will be the transition between recording in the CRL of all of the Linky project impacts and the start of the reconciliation of the CRL.

For the 2021-2024 period, the amounts recorded in the CRL and then reconciled, specified by the above-mentioned deliberation, are as follows:

In nominal €million	2021	2022	2023	2024
Amounts recorded (+) or reconciled (-) in the CRL	228	7	- 165	- 291

The amounts recorded in the CRL are deducted, each year of the TURPE 5 tariff period, from Enedis's total allowed revenue. As from 2023, the CRL will be gradually reconciled each year, through an upward tariff adjustment, until it is fully reconciled, scheduled for 2030. The CRL is remunerated at the cost of debt adopted by CRE for the calculation of the basic remuneration rate for the Linky project.

3. Reference values for tariff revenue forecasts

The amount adopted for the calculation of the definitive allowed revenue is equal to the revenues actually received by Enedis (including R_f).

Revenue forecasts are based on the following elements:

- Forecast supply volumes and number of customers:

[84] Deliberation by the French Energy Regulatory Commission of 17 July 2014 deciding on the incentive regulation framework for ERDF's smart metering system in the BT ≤ 36 kVA voltage level

	2021	2022	2023	2024
Volume supplied (TWh)	340.7	343.5	346.4	349.2
Number of customers connected (in thousands)	37,527	37,864	38,205	38,548

On an indicative basis, the forecast revenue values, excluding R_f, received by Enedis are as follows:

In nominal €million	2021	2022	2023	2024
Forecast revenues received excluding R_f by Enedis	14,058	14,236	14,707	15,094

ANNEX 3 – INCENTIVE REGULATION FOR EXPENSES RELATED TO POWER LOSSES COMPENSATION (CONFIDENTIAL ANNEX)

This annex is confidential.

ANNEX 4: INCENTIVE REGULATION FOR ENEDIS'S UNIT COSTS OF INVESTMENTS (CONFIDENTIAL ANNEX)

This annex is confidential.

ANNEX 5 – INCENTIVE REGULATION FOR "NON-GRID" CAPITAL EXPENSES

As presented in section 2.3.2.2, for the TURPE 6 period CRE is re-adopting an incentive regulation mechanism for “non-grid” capital expenses.

This mechanism incentivises Enedis 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, vehicles and information systems.

With regard to information systems, some projects are excluded from the scope of incentive regulation. These are projects falling under cybersecurity or that are related to the communication channel and digitalisation of the operator’s activity.

The list of the projects concerned is as follows:

Project
B4ALL
CYBER
Smartgrids
I/OT
Plateforme Services des chaînes communicantes
OKOUME
LINCS
SI Exploitant
STM

This list may be updated during the TURPE 6 HTA-BT period in connection with any new developments associated with the projects listed above.

ANNEX 6 - INCENTIVE REGULATION FOR QUALITY OF SERVICE

The provisions of the present annex do not preclude DSOs from sending to CRE other indicators which are not explicitly indicated hereafter.

For indicators corresponding to rates, CRE requests each DSO to also send it its calculation details (numerator and denominator).

1. Enedis

This part of the annex outlines the indicators for following Enedis's quality of service as well as the corresponding financial incentives defined for TURPE 6 HTA-BT. With regard to scheduled appointments missed by the DSO and provision of connections not performed at the date agreed on with the user, the payment of penalties specified by TURPE 6 HTA-BT does not deprive customers of the right to seek the liability of the DSO through procedures of ordinary law.

CRE requests Enedis to work, within the framework of the electricity working group (GTE), on extending the accessible times for its telephone platforms, in particular the supplier line.

1.1. Follow-up indicators for Enedis's quality of service giving rise to financial incentives

1.1.1. Scheduled appointments missed by Enedis

Calculation	*Number of scheduled appointments missed by the DSO and giving rise to the payment of a penalty by the DSO during the quarter, by user category*
Scope	- All appointments for interventions with a visit by one of the DSO's agents scheduled and therefore validated by the DSO and requiring the presence of the user, missed because of the DSO
Monitoring	- Frequency of calculation: quarterly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly
Objective	- 100% of missed appointments systematically identified by the operator are compensated
Incentives	- Penalty amount identical to that billed by Enedis in the case of non-execution of a scheduled intervention because of the user or supplier (missed appointment, etc.) - Payment to the end user through the supplier for users under single contracts or directly to the user in the case of users having signed a grid access contract directly with the DSO
Implementation date	- Automation implemented since 1 January 2015

1.1.2. Deadline for transmitting to RTE the half-hourly measurement curves of each balance responsible party

Calculation	*Rate of compliance with the deadline for submitting to RTE the Overall consumption balances of balance responsible parties declared active (with sites) in Enedis's network for week W-2 in week W*
Scope	Following measurement curves (MC): - Aggregated MC of the consumption of sites with telemetered measurement curves - Aggregated MC of consumption of sites with indices (profile-based) - Aggregated MC of the production of sites with telemetered measurement curves - Aggregated MC of the production sites with indices (profile-based)
Monitoring	- Frequency of calculation: quarterly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual as from the entry into effect of tariffs
Objective	- Reference objective: 98% per calendar year
Incentives	- Penalties: €2,500 per calendar year per tenth of a point below the reference objective - Incentive floor value: - €150 k - Payment through CRCP

Implementation date	1 August 2009

1.1.3. Rate of response to claims within 15 calendar days

Calculation	_Number of claims closed in month M whose response time (closure date in the SGE portal) is lower than or equal to 15 calendar days after the filing date in SGE / Number of claims closed in the SGE during month M_
Scope	- All claims sent directly by users or through suppliers whose response must be made by the DSO, closed in the SGE - All written or oral means of reporting a claim, entered in the SGE - All user categories - Claim closed: claim for which a "meaningful" response, and not a simple acknowledgement of receipt, has been sent by the DSO
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective: o from 1 January 2021 to 31 December 2021: 93% o from 1 January 2022 to 31 December 2022: 94% o from 1 January 2023 to 31 December 2023: 95% o from 1 January 2024 to 31 December 2024: 95%
Incentives	- Penalties: €80,000 per calendar year per tenth of a point below the reference objective - Bonus: €80,000 per calendar year per tenth of a point above the reference objective - Incentive floor value: ± €10 million - Payment through CRCP
Implementation date	1 January 2014

1.1.4. Rate of multiple claims filtered

Calculation	_Number of multiple claims for the same connection point and the same type of claim / Total number of claims_
Scope	- All claims sent directly by users or through suppliers whose response must be made by the DSO, closed in the SGE - All written or oral means of reporting a claim, entered in the SGE - All user categories
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	Reference objective for BT ≤ 36 kVA users: o from 1 January 2021 to 31 December 2021: 9.7% o from 1 January 2022 to 31 December 2022: 9.5% o from 1 January 2023 to 31 December 2023: 9.2% o from 1 January 2024 to 31 December 2024: 9%
Incentives	- Penalties: €25,000 per calendar year per tenth of a point below the reference objective - Bonus : €25,000 per calendar year per tenth of a point above the reference objective - Incentive floor value: ± €5 million - Payment through CRCP
Implementation date	1 January 2021

1.1.5. Number of penalties paid for connections not made available at the date agreed on with the user

Calculation	_Number of claims for connections not made available at the date agreed on with the user giving rise to the payment of a penalty during the quarter_
Scope	- 100% of connections not made available at the date agreed on with the user, upon a claim filed by the user - All withdrawal and injection connections
Monitoring	- Frequency of calculation: quarterly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly
Incentives	- Penalties: o €50 for BT ≤ 36 kVA connections o €150 for BT > 36 kVA and collective in BT o €1,500 for HTA connections - The amounts and conditions for the payment of penalties must appear visibly and in detail in the connection procedures and contract documents - Payment: upon the filing of the claim, to the connection applicant, or to the representative in the case of a special representation mandate
Implementation date	- 1 January 2014

1.1.6. Rate of compliance with the sending of the connection agreement within the procedure deadline or the deadline requested by the client

Calculation	_Number of connection proposals sent within the maximum deadline resulting from the qualification of the request or within the deadline requested by the client during month M / Total number of connection proposals sent during month M_
Scope	- All withdrawal and injection connections
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	Reference objective for BT ≤ 36 kVA users: o from 1 January 2021 to 31 December 2021: 91% o from 1 January 2022 to 31 December 2022: 92% o from 1 January 2023 to 31 December 2023: 93% o from 1 January 2024 to 31 December 2024: 94% Reference objective for BT > 36 kVA users , collective users in BT and HTA: o from 1 January 2021 to 31 December 2021: 91% o from 1 January 2022 to 31 December 2022: 92% o from 1 January 2023 to 31 December 2023: 93 % o from 1 January 2024 to 31 December 2024: 94 %
Incentives	BT ≤ 36 kVA users - Penalties: (€165 x 0.1% x V) per calendar year per tenth of a point below the reference objective where V corresponds to the volume of connection proposals sent for BT ≤ 36 kVA users during the year - Bonus : (€165 x 0.1% x V) per calendar year per tenth of a point above the reference objective where V corresponds to the volume of connection proposals sent for BT ≤ 36 kVA users during the year BT > 36 kVA users , collective users in BT and HTA

	- Penalties: (€745 x 0.1% x V) per calendar year per tenth of a point below the reference objective where V corresponds to the volume of connection proposals sent for BT > 36 kVA users, collective in BT and HTA during the year - Bonus : (€745 x 0.1% x V) per calendar year per tenth of a point above the reference objective where V corresponds to the volume of connection proposals sent for BT > 36 kVA users, collective in BT and HTA during the year - Incentive floor value: ± €7 million - Payment through CRCP
Implementation date	1 January 2017

1.1.7. Average timeframe for performing connection operations by connection category

Calculation	*Average number of calendar days between the date of client agreement on the connection quote (most recent date of signing of the connection agreement for the Producer BT>36 kVA and HTA category) and the date of bill dispatch by Enedis following the implementation of the connection (date of commissioning of the installation for the Producer BT>36 kVA and HTA category)*[85]

Scope	- All withdrawal and injection connections, for which the date of bill dispatch falls witin the month of calculation, of the following categories:
	  o individual withdrawal connections in BT≤ 36 kVA without grid extension;
	  o BT ≤ 36 kVA connections with grid extension;
	  o injection additions in existing connections;
	  o withdrawal connections in BT > 36 kVA with and without grid extension;
	  o collective connections;
	  o withdrawal connections in the HTA network;
	  o producer connections for BT > 36 kVA and HTA installations

Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual

Objective	Reference objective for individual withdrawal connections in BT≤ 36 kVA without grid extension in calendar days:
	  o from 1 January 2021 to 31 December 2021: 74 days
	  o from 1 January 2022 to 31 December 2022: 68 days
	  o from 1 January 2023 to 31 December 2023: 62 days
	  o from 1 January 2024 to 31 December 2024: 56 days
	
	Reference objective for injection additions for existing connections, in calendar days:
	  o from 1 January 2021 to 31 December 2021: 31 days
	  o from 1 January 2022 to 31 December 2022: 28 days
	  o from 1 January 2023 to 31 December 2023: 26 days
	  o from 1 January 2024 to 31 December 2024: 23 days
	
	Reference objective for connections in BT≤ 36 kVA with grid extension, in calendar days:
	  o from 1 January 2021 to 31 December 2021: 150 days
	  o from 1 January 2022 to 31 December 2022: 141 days
	  o from 1 January 2023 to 31 December 2023: 131 days
	  o from 1 January 2024 to 31 December 2024: 121 days
	
	Reference objective for withdrawal connections in BT>36 kVA with and without grid extension, in calendar days:
	  o from 1 January 2021 to 31 December 2021: 141 days
	  o from 1 January 2022 to 31 December 2022: 138 days
	  o from 1 January 2023 to 31 December 2023: 134 days

[85] Moreover, CRE requests Enedis to calculate and transmit, for all categories, the timeframe between the agreement date on the technical and financial proposal and the work completion date.

	○ from 1 January 2024 to 31 December 2024: 131 days Reference objective for collective connections, in calendar days: ○ from 1 January 2021 to 31 December 2021: 219 days ○ from 1 January 2022 to 31 December 2022: 199 days ○ from 1 January 2023 to 31 December 2023: 180 days ○ from 1 January 2024 to 31 December 2024: 160 days Reference objective for withdrawal connections in the HTA network, in calendar days: ○ from 1 January 2021 to 31 December 2021: 190 days ○ from 1 January 2022 to 31 December 2022: 175 days ○ from 1 January 2023 to 31 December 2023: 160 days ○ from 1 January 2024 to 31 December 2024: 145 days Reference objective for producer connections for BT>36 kVA and HTA installations, in calendar days: ○ from 1 January 2021 to 31 December 2021: 195 days ○ from 1 January 2022 to 31 December 2022: 180 days ○ from 1 January 2023 to 31 December 2023: 165 days ○ from 1 January 2024 to 31 December 2024: 150 days
Incentives	Individual withdrawal connections in BT≤ 36 kVA without grid extension - Penalties: (€4.6 x V) per calendar day above the reference objective where V corresponds to the volume of individual withdrawal connections in BT≤ 36 kVA without grid extension, during the year - Bonus : (€3.2 x V) per calendar day below the reference objective where V corresponds to the volume of individual withdrawal connections in BT≤ 36 kVA without grid extension, during the year - Incentive floor value: - €5 million for penalties / + €3.5 million for bonuses injection additions in existing connections: - Penalties: (€29.8 x V) per calendar day above the reference objective where V corresponds to the volume of injection additions in existing connections, during the year - Bonus : (€18.6 x V) per calendar day below the reference objective where V corresponds to the volume of injection additions in existing connections, during the year - Incentive floor value: - €2 million for penalties / + €1.25 million for bonuses BT ≤ 36 kVA connections with grid extension - Penalties: (€17.9 x V) per calendar day below the reference objective where V corresponds to the volume of connections in BT≤ 36 kVA with grid extension, during the year - Bonus : (€11.2 x V) per calendar day below the reference objective where V corresponds to the volume of connections in BT≤ 36 kVA with grid extension, during the year - Incentive floor value: - €2 million for penalties / + €1.25 million for bonuses Withdrawal connections in BT > 36 kVA with and without grid extension: - Penalties: (€16.2 x V) per calendar day above the reference objective where V corresponds to the volume of connections in BT> 36 kVA with and without grid extension, during the year - Bonus: (€10.1 x V) per calendar day below the reference objective where V corresponds to the volume of connections in BT> 36 kVA with and without grid extension, during the year - Incentive floor value: - €2 million for penalties / + €1.25 million for bonuses Collective connections: - Penalties: (€6.2 x V) per calendar day above the reference objective where V corresponds to the volume of collective connections during the year - Bonus: (€4.4 x V) per calendar day below the reference objective where V corresponds to the volume of collective connections during the year - Incentive floor value: - €2.5 million for penalties / + €1.75 million for bonuses Withdrawal connections in the HTA network: - Penalties: (€202.1 x V) per calendar day above the reference objective where V corresponds to the volume of connections in the HTA network during the year - Bonus: (€141.5 x V) per calendar day below the reference objective where V corresponds to the volume of connections in the HTA network during the year

	- Incentive floor value: - €5 million for penalties / + €3.5 million for bonuses <u>Producer connections for BT > 36 kVA and HTA installations:</u> - Penalties: (€40.3 x V) per calendar day above the reference objective where V corresponds to the volume of connections in the HTA network during the year - Bonus: (€28.2 x V) per calendar day below the reference objective where V corresponds to the volume of connections in the HTA network during the year - Incentive floor value: - €2.5 million for penalties / + €1.75 million for bonuses - Payment through CRCP
Implementation date	1 January 2021

1.1.8. Availability rate of the function "interrogation of data useful for the service order" of the supplier and third-party portal

Calculation	<u>*Number of hours of availability during the week during the service guarantee period / Total number of hours of service guarantee of the SGE portal during the week*</u> *The service guarantee times for the SGE portal taken into account are as follows: 7.00 a.m. to 9.00 p.m. from Monday to Saturday except holidays*
Scope	- Function "interrogation of data useful for the service order" of the SGE portal used to characterise availability of the SGE portal - Causes of unavailability: any event, not scheduled or scheduled less than 48 hours in advance, heavily preventing, disturbing or slowing, particularly due to instability, suppliers' use of this function of the portal
Monitoring	- Frequency of calculation: weekly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual as from the entry into effect of tariffs
Objective	- The financial incentive covers the rate value calculated on an annual basis - Reference objective: 99% per calendar year
Incentives	- Penalties: €50,000 per one-tenth of a point if the annual rate is strictly lower than the reference objective - Incentive floor value: - €1.75 million - Payment through CRCP
Implementation date	1 August 2009

1.1.9. Accessibility rate of the special supplier telephone line

Calculation	<u>*Number of calls served (calls picked up by an operator) on the "urgent affairs" line for phone reception relating to supply during the quarter / Number of calls received during the month on the "urgent affairs" line for phone reception relating to supply during the quarter*</u>
Scope	- All withdrawal and injection connections
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	<u>Reference objective:</u> o from 1 January 2021 to 31 December 2021: 95% o from 1 January 2022 to 31 December 2022: 95.5% o from 1 January 2023 to 31 December 2023: 96% o from 1 January 2024 to 31 December 2024: 96.5%
Incentives	- Penalties: €30,000 per calendar year per tenth of a point below the reference objective - Bonus: €30,000 per calendar year per tenth of a point above the reference objective - Incentive floor value: ± €1 million - Payment through CRCP

Implementa-tion date	1 January 2021

1.1.10. Call rate for the special supplier line with a wait time of less than 90 seconds

Calculation	*Number of calls served (calls picked up by an operator) with a wait time lower than 90 seconds on the “urgent affairs” line for phone reception relating to supply during the quarter / Number of calls to be processed during the month on the “urgent affairs” line for phone reception relating to supply during the quarter*
Scope	- All withdrawal and injection connections
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	Reference objective: o from 1 January 2021 to 31 December 2021: 74% o from 1 January 2022 to 31 December 2022: 76% o from 1 January 2023 to 31 December 2023: 78% o from 1 January 2024 to 31 December 2024: 80%
Incentives	- Penalties: €60,000 per calendar year per tenth of a point below the reference objective - Bonus: €60,000 per calendar year per tenth of a point above the reference objective - Incentive floor value: ± €3 million - Payment through CRCP
Implementa-tion date	1 January 2021

1.1.11. Energy adjusted and normalised in Recotemp

Calculation	*Sum for each BRP and for each half-hour of the absolute value of the difference between the energy attributed in Recotemp before adjustment and normalisation and the energy attributed after adjustment and normalisation, as a percentage of the sum of absolute values of profile-based consumption and production*
Scope	- Profile-based consumption of all BRPs
Monitoring	- Frequency of calculation: annual - Frequency of reporting to CRE: annual - Frequency of publication: annual - Frequency of incentive calculation: annual
Objective	- Reference objective: o 2021 (RT 16): 3.97% o 2022 (RT 17): 3.87% o 2023 (RT 18): 3.77% o 2024 (RT 19): 3.67%
Incentives	- Penalties: €250,000 per tenth of a point above the reference objective - Bonus: €250,000 per tenth of a point below the reference objective - Incentive floor value: ± €2.5 million - Payment through CRCP
Implementa-tion date	1 October 2018

1.1.12. Imbalances in Enedis’s balancing perimeter

Calculation	*Annual volume of imbalances attributable to Enedis’s balancing perimeter*
Scope	- Enedis’s balancing perimeter
Monitoring	- Frequency of calculation: annual - Frequency of reporting to CRE: annual - Frequency of publication: annual
Objective	- Reference objective: 4% of the power losses volumes observed
Incentives	- If the volume of power losses is higher than 4% of losses observed, an audit will be performed by CRE to verify the uncontrollable nature of the causes of the increase in the imbalance volume.

	If, following this audit, the uncontrollable nature of the causes of the increase in the imbalance volume is not proven, the difference in expenses related to power losses compensation will only take into account the expenses within the limit of 4% of the volume of power losses recorded.
Implementation date	1 October 2018 This indicator will be eliminated with the switch to the target system: loop losses.

1.1.13. Quality of forecast power losses relating to unallocated energy

Calculation	*Sum of absolute values, in energy, of unallocated energy not normalised, in half-hourly increments divided by the sum of profile-based consumption and production in Enedis's perimeter*
Scope	- Enedis's balancing perimeter
Monitoring	- Frequency of calculation: annual - Frequency of reporting to CRE: annual - Frequency of publication: annual - Frequency of incentive calculation: annual
Objective	o 2021 (RT 16): 1.8% o 2022 (RT 17): 1.65% o 2023 (RT 18): 1.5% o 2024 (RT 19): 1.35%
Incentives	- Penalties: €250,000 per tenth of a point above the reference objective - Bonus: €250,000 per tenth of a point below the reference objective - Incentive floor value: ± €2.5 million - Payment through CRCP
Implementation date	1 January 2021 This indicator will be eliminated with the switch to the target system: loop losses.

1.2. Other indicators for follow-up of quality of service

1.2.1. Indicators relating to interventions

Indicator name	Indicator calculation	Calculation frequency
Rate of terminations performed within the deadlines requested by user category	Number of terminations at the user's initiative closed and performed within the deadline requested (if this deadline is greater than the catalogue deadline as a result of the user) or within the catalogue deadline (if the deadline requested by the user is earlier than or equal to the catalogue deadline) / Total number of terminations closed and performed in the month	Monthly
Rate of terminations by deadline brackets and user category	Number of termination affairs closed and performed in the month in the predefined deadline bracket / Number of termination affairs closed and performed in the month	Monthly
Rate of commissioning performed within the deadlines requested by user category	Number of commissioning closed and performed within the deadline requested by the user (if this deadline is greater than the catalogue deadline as a result of the user) or within the catalogue deadline (if the deadline requested by the user is earlier than or equal to the catalogue deadline) / Total number of commissioning closed and performed in the month	Monthly
Rate of commissioning by deadline brackets and user category	Number of commissioning in existing installations closed in the month and performed in the predefined deadline bracket / Number of commissioning affairs closed and performed in the month	Monthly
Rate of supplier changes performed within the deadlines requested by user category	Number of supplier changes closed and performed within the deadline requested by the user (if this deadline is greater than the catalogue deadline as a result of the user) or within the catalogue deadline (if the deadline requested by the user is earlier than or equal to the catalogue deadline) / Number of supplier changes closed and performed in the month	Monthly
Rate of supplier changes performed by deadline bracket and user category	Number of supplier changes closed and performed in the month in the predefined deadline bracket / Number of supplier changes closed and performed in the month	Monthly
Rate of commissioning with a visit at the date requested by the client	Number of commissioning in existing installations with a visit closed during month M and performed at the date requested by the client (if the deadline requested is later than the catalogue deadline as a result of the user) or performed within a deadline earlier than or equal to the catalogue deadline (if the deadline requested is earlier than or equal to the catalogue deadline) / Total number of commissioning closed in the SGE during month M	Monthly
Appointments rescheduled at the initiative of Enedis	Number of appointments rescheduled by the DSO (excluding rescheduling within the catalogue deadline) by user category	Monthly

1.2.2. Indicators concerning user relations

Indicator name	Indicator calculation	Calculation frequency
Number of claims received by the DSO by type and user category	Number of user claims received by the DSO during the quarter for each of the following types: - Reception - Quality of the processing of the service requested - Quality and continuity of supply - Works and connection Metering and billing supply	Quarterly

Rate of response to claims within 5 calendar days by type and user category	Number of claims closed in the month for which the response date (date of closure in SGE) is lower than or equal to 5 calendar days after the date of filing in SGE / Number of claims closed in the month	Monthly
Rate of response to claims within 15 calendar days by type and user category	Number of claims closed in the month for which the response date (date of closure in SGE) is lower than or equal to 15 calendar days after the date of filing in SGE / Number of claims closed in the month	Monthly
Rate of response to claims within more than 30 calendar days by type and user category	Number of claims closed in the month for which the response date (date of closure in SGE) is higher than 60 calendar days after the date of filing in SGE / Number of claims closed in the month	Monthly
Rate of telephone availability for customer support and repair	Number of phone calls answered during the quarter / Number of phone calls received during the quarter	Quarterly
Number of admissible claims received by the national energy mediator concerning Enedis	Number of admissible claims received by the national energy mediator concerning Enedis	Quarterly
Perceived quality of connection services	Rate of clients “not at all satisfied” following a connection service by Enedis, by user category	Monthly
Perceived quality of services (excluding connection)	Rate of clients “not at all satisfied” following a service by Enedis excluding connection, by user category	Monthly

1.2.3. Indicators related to metering and billing

Indicator name	Indicator calculation	Calculation frequency
Rate of monthly metering published based on real indices for BT > 36 kVA and HTA users under single contracts	Number of meters for BT>36 kVA and HTA withdrawals read published based on real indices during the month / Number of BT > 36 kVA and HTA meters to be read during the month	Monthly
Rate of absence at two or more meter readings of BT ≤ 36 kVA customers	Number of meters not read two or more times due to the absence of the client and without self-metering / Number of meters to be read during the month	Quarterly
Rate of electricity indices read and self-read per half-year period	Number of meters having had at least one index read or self-read over the last six months / Number of meters to be read during the last six months	Monthly
Rate of indices rectified for BT ≤ 36 kVA customers	Sum of “Adjustments bills credits” for “Index adjustment” excluding “Fraud” emitted during the month / Sum of readings for the month	Monthly

1.2.4. Indicators relating to connections

Indicator name	Indicator calculation	Calculation frequency
Rate of telephone availability for electricity connection reception	Number of phone calls answered during the quarter / Number of phone calls received during the quarter	Quarterly
Average timeframe for sending connection proposal by user category	Sum of timeframes for sending connection proposals as from the qualification of the request / Number of connection proposals made during the quarter	Quarterly

Rate of connection proposals sent outside the deadline by user category	Number of connection proposals not sent within the maximum timeframe resulting from the qualification of the request (in compliance with connection request processing procedures) / Number of connection proposals made during the quarter	Quarterly
Number of claims paid under order no. 2012-38 of 10 January 2012 for electricity production installations using renewable energy sources of power ≤ 3 kVA for the part on deadline for sending the connection agreement	Number of claims for exceeding the deadline for sending the convention agreement defined by the decree giving rise to the payment of compensation during the quarter	Quarterly
Number of claims paid under order no. 2012-38 of 10 January 2012 for electricity production installations using renewable energy sources of power ≤ 3 kVA for the part on deadline for carrying out connection works	Number of claims for exceeding the deadline for implementing the connection defined by the decree giving rise to the payment of compensation during the quarter	Quarterly
Timeframe for implementing provisional connections	Average timeframe for implementing a provisional connection calculated between the date of receipt of the request and the date of implementation of the connection	Quarterly

1.2.5. Indicators relating to the reliability of the electricity balance

Indicator name	Indicator calculation	Calculation frequency
Difference between the Ecarts and Recotemp electricity balance processes	Sum of the absolute values of the difference, for each BRP and each half-hour, between the volumes attributed in Recoflux (M+12) and those attributed in Recotemp	Annual
Energy not allocated in Recotemp	Annual volume of energy not allocated in Recotemp	Annual
Quality of power losses forecast in half-hour intervals	Sum of the absolute values of the difference in half-hour intervals, between the power losses made and the power losses purchased by Enedis, divided by the volume of power losses made	Annual
Quality of power losses forecast in daily intervals	Sum of the absolute values of the difference in daily intervals, between the power losses made and the power losses purchased by Enedis, divided by the volume of power losses made	Annual
Deadline for transmitting to RTE the half-hourly measurement curves of each balance responsible party	Rate of compliance with the deadline for submitting to RTE the Overall consumption balances of balance responsible parties declared active (with sites) in Enedis's network for week W-1 in week W	Quarterly

2. Local distribution companies serving over 100,000 clients and EDF SEI

This part of the annex outlines the indicators for following the quality of service of LDCs serving over 100,000 clients and EDF SEI as well as the corresponding financial incentives defined for TURPE 6 HTA-BT.

This list may be completed for LDCs having opted for the establishment, by CRE on the basis of their accounts, of their contribution to the electricity equalisation fund.

2.1. Follow-up indicator for quality of service giving rise to financial incentives

2.1.1. Scheduled appointments missed by the DSO

Calculation	<u>*Number of scheduled appointments missed by the DSO giving rise to the payment of a penalty by the DSO during the quarter, by user category*</u>

Scope	- All appointments scheduled, therefore validated by the DSO - All appointments for interventions with a visit by one of the DSO's agents and requiring the presence of the user, missed because of the DSO
Monitoring	- Frequency of calculation: quarterly - Frequency of reporting to CRE: annual - Frequency of publication: annual
Objective	- 100% of missed appointments systematically identified by the operator are compensated
Incentives	Penalty amount identical to that billed by the DSO in the case of non-execution of a scheduled intervention because of the user or supplier (missed appointment, etc.)
Implementation date	1 January 2014

2.2. Other indicators for follow-up of quality of service

The conditions for calculating the indicators may be adapted based on the specificities of the LDCs serving more than 100,000 clients.

Indicator name	Indicator calculation	Calculation frequency
Number of claims received type and user category	Number of user claims received by the DSO during the quarter for each of the following types: - Reception - Quality of the processing of the service requested - Quality and continuity of supply - Works and connection - Metering and billing supply	Quarterly
Rate of response to claims within 15 calendar days	Number of claims for which the response date is lower than or equal to 15 calendar days after the date of receipt of the claim by the distributor / Number of claims closed during the quarter	Quarterly
Rate of meters with at least one reading in the year based on a real index for BT ≤ 36 kVA customers	(Number of meters to be read – number of meters with two or more absences for meter reading) / Number of meters to be read during the quarter	Quarterly
Rate of connection proposals sent outside the deadline by user category	Number of connection proposals not sent within the maximum timeframe resulting from the qualification of the request (in compliance with connection request processing procedures) / Number of connection proposals made during the quarter	Quarterly
Rate of compliance with the date agreed on for the provision of the connection by user category	Number of connections made available at the date agreed on with the user / Number of connections made available during the quarter	Quarterly
Rate of terminations performed within the deadlines requested by user category	Number of terminations at the user's initiative closed and performed within the deadline requested (if this deadline is greater than the catalogue deadline as a result of the user) or within the catalogue deadline (if the deadline requested by the user is earlier than or equal to the catalogue deadline)	Quarterly

	/ Total number of terminations closed and performed in the month	
Rate of commissioning performed within the deadlines requested by user category	Number of commissioning closed and performed within the deadline requested by the user (if this deadline is greater than the catalogue deadline as a result of the user) or within the catalogue deadline (if the deadline requested by the user is earlier than or equal to the catalogue deadline) / Total number of commissioning closed and performed in the month	Quarterly
Average timeframe for completing connection works by connection category	Average timeframe calculated between the client's agreement with the connection quote and the date of the end of work under the responsibility of the DSO, calculated by connection category	Quarterly
Deadline for transmitting to RTE the half-hourly measurement curves of each balance responsible party	Rate of compliance with the deadline for submitting to RTE the Overall consumption balances of balance responsible parties declared active (with sites) in the DSO's network for week W-1 in week W	Quarterly

ANNEX 7 - INCENTIVE REGULATION FOR SUPPLY QUALITY

The provisions of the present annex do not preclude DSOs from sending to CRE other indicators which are not explicitly indicated hereafter. In addition, these provisions do not preclude the transmission, to the participants concerned and in particular to concessionary authorities, of indicators relating to the quality of public electricity distribution networks.

Moreover, CRE requests the different DSOs to submit to it quantitative elements on the territorial dispersion of results in terms of supply quality (consideration of the different geographical zones[86] and population densities).

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.

This definition does not apply to EDF SEI following CRE's deliberation of 19 December 2019[87].

2. Penalty mechanism for long outages

The mechanism described below is applicable to all distribution system operators, including LDCs serving fewer than 100,000 clients. The payment of this compensation or reduction does not deprive customers of the right to seek the liability of the DSO through procedures of ordinary law.

Calculation	*Flat-rate penalty paid to consumers, broken down by voltage level and by five-hour outage periods*
Scope	- Any supply interruptions of a duration higher than 5 hours due to a failure attributable to the public distribution grid managed by the DSO, including in the case of exceptional events, within the limit of 40 consecutive periods of 5 hours. - In the case of a power cut of more than 20% of all end customers supplied directly or indirectly by the public transmission grid, the penalty will not be paid to customers on the mainland. - In the case of a supply interruption of a duration higher than 5 hours due to a failure attributable to the public grid located upstream of those managed by the DSO, the penalty amount that the DSO is required to pay to the customers concerned is reimbursed to it by the upstream grid operator. - This mechanism concerns only withdrawal points.
Incentives	- For customers connected in the BT range whose subscribed power is lower than or equal to 36 kVA, the penalty is €2 (before tax) per kVA of subscribed power per 5-hour outage period. - For customers connected in the BT range whose subscribed power is higher than 36 kVA, the penalty is €3.5 (before tax) per kVA of subscribed power per 5-hour outage period.

[86] In the case of zones not interconnected to mainland France, the geographical zones correspond to each of the territories.
[87] CRE deliberation no. 2019-301 of 19 December 2019 deciding on the amendment of the deliberation of 22 March 2018 on the levels of contribution to the electricity equalisation fund (FPE) for EDF SEI for the years 2018 to 2021 and on the associated regulatory framework

	- For customers connected in the HTA range, the compensation is €3.5 (before tax) per kVA of subscribed power per 5-hour outage period. *LDCs and EDF SEI maintain the possibility, in the case of cuts related to an exceptional event, of reducing the amounts of penalties applicable, compared to the normal penalties defined above. The amounts of reduced penalties applicable in these situations shall be proportional to the normal penalty amounts and cannot be lower than 10% of these amounts. The amounts of normal penalties remain applicable for cuts other than those related to an exceptional event. Each DSO must, where applicable, publish and transmit to CRE the proportional reduction factor it implements.*
Implementation date	1 August 2017

3. Enedis

3.1. Follow-up indicators for Enedis's continuity of supply giving rise to financial incentives

3.1.1. Average outage duration in BT (B criterion)

Calculation	*The average outage duration of year N in BT (DMC_N^{BT}), also called B criterion, is defined as the ratio (i) between the duration of long outages (over 3 minutes) of consumption installations connected in BT and (ii) the total number of consumption installations connected in BT as at 31 December of year N.* $\mathrm{DMC}_{\mathrm{N}}^{\mathrm{BT}} = \frac{\sum_{\text{Year N}} \text{Durations of long outages}^{88} \text{ in consumption installations connected in BT}}{\text{Total number of consumption installations connected in BT as 31 December of year N}}$
Scope	- $\mathrm{DMC}_{\mathrm{N}}^{\mathrm{BT}}$is determined excluding incidents related to exceptional events and excluding causes related to the public transmission grid (or to load shedding).
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective ($\mathrm{DMC}_{\mathrm{Nref}}^{\mathrm{BT}}$) : ○ from 1 January 2021 to 31 December 2024: 62 minutes
Incentives	- $\text{Bonus (or penalty for negative values)} = €6,.4 \text{ million/minute} \times \left(\mathrm{DMC}_{\mathrm{Nref}}^{\mathrm{BT}} - \mathrm{DMC}_{\mathrm{N}}^{\mathrm{BT}}\right)$ - Payment through CRCP
Implementation date	1 August 2009

3.1.2. Average outage duration in HTA (M criterion)

Calculation	*Average outage duration of year N in HTA (DMC_N^{HTA}), also called M criterion, is defined as the average duration of long outages (over 3 minutes) of HTA clients weighted by the subscribed power of these same clients as at 31 December of year N.* $\mathrm{DMC}_{\mathrm{N}}^{\mathrm{HTA}} = \frac{\sum_{\text{Year N}} \text{Durations of long outages}^{89} \text{ of consumption installations connected in HTA weighted by their subscribed power}}{\text{Cumulated subscribed power of consumption installations connected in HTA as at 31 Decemebr of year N}}$
Scope	- $\mathrm{DMC}_{\mathrm{N}}^{\mathrm{HTA}}$is determined excluding incidents related to exceptional events and excluding causes related to the public transmission grid (or to load shedding).
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual

[88] Long outages are those that are longer than three minutes.
[89] *Ibid.*

Objective	- Reference objective ($\mathrm{DMC}_{\mathrm{Nref}}^{\mathrm{HTA}}$): ○ from 1 January 2021 to 31 December 2021: 42.1 minutes ○ from 1 January 2022 to 31 December 2022: 41.8 minutes ○ from 1 January 2023 to 31 December 2023: 41.5 minutes ○ from 1 January 2024 to 31 December 2024: 41.2 minutes
Incentives	- $\text{Bonus (or penalty for negative values)} = €5.9\ \text{million/minute} \times \left(\mathrm{DMC}_{\mathrm{Nref}}^{\mathrm{HTA}} - \mathrm{DMC}_{\mathrm{N}}^{\mathrm{HTA}}\right)$ - Payment through CRCP
Implementa-tion date	1 January 2017

3.1.3. Average outage frequency in BT (F-BT criterion)

Calculation	*The average outage frequency of year N in BT (FMC_N^{BT}), also called F-BT criterion, is defined as the ratio between (i) the number of long (over 3 minutes) and short outages (between 1 second and 3 minutes) of consumption installations connected in BT and (ii) the total number of consumption installations connected in BT as at 31 December of year N.* $$\mathrm{FMC}_{\mathrm{N}}^{\mathrm{BT}} = \frac{\sum_{\text{Year N}} \text{Number of long}^{90} \text{ and short}^{91} \text{ outages of consumption installations connected in BT}}{\text{Total number of consumption installations connected in BT as at 31 December of year N}}$$
Scope	- $\mathrm{FMC}_{\mathrm{N}}^{\mathrm{BT}}$ is determined excluding incidents related to exceptional events and excluding causes related to the public transmission grid (or to load shedding).
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective ($\mathrm{FMC}_{\mathrm{Nref}}^{\mathrm{BT}}$): ○ from 1 January 2021 to 31 December 2021: 1.72 outages per year ○ from 1 January 2022 to 31 December 2022: 1.60 outages per year ○ from 1 January 2023 to 31 December 2023: 1.47 outages per year ○ from 1 January 2024 to 31 December 2024: 1.34 outages per year
Incentives	- $\text{Bonus (or penalty for negative values)} = €4\ \text{million/annual outage} \times \left(\mathrm{FMC}_{\mathrm{Nref}}^{\mathrm{BT}} - \mathrm{FMC}_{\mathrm{N}}^{\mathrm{BT}}\right)$ - Payment through CRCP
Implementa-tion date	1 January 2017

3.1.4. Average outage frequency in HTA (F-HTA criterion)

Calculation	*The average outage frequency of year N in HTA (FMC_N^{HTA}), also called F-HTA criterion, is defined as the ratio between (i) the number of long (over 3 minutes) and short outages (between 1 second and 3 minutes) of consumption installations connected in HTA and (ii) the total number of consumption installations connected in HTA as at 31 December of year N.* $$\mathrm{FMC}_{\mathrm{N}}^{\mathrm{HTA}} = \frac{\sum_{\text{Year N}} \text{Number of long}^{92} \text{ and short outages}^{93} \text{ of consumption installations connected in HTA}}{\text{Total number of consumption installations connected in HTA as at 31 December of year N}}$$
Scope	- $\mathrm{FMC}_{\mathrm{N}}^{\mathrm{HTA}}$ is determined excluding incidents related to exceptional events and excluding causes related to the public transmission grid (or to load shedding).
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective ($\mathrm{FMC}_{\mathrm{Nref}}^{\mathrm{HTA}}$):

[90] *Ibid.*
[91] Short outages are those lasting between one second and three minutes.
[92] Long outages are those that are longer than three minutes.
[93] Short outages are those lasting between one second and three minutes.

	○ from 1 January 2021 to 31 December 2021: 1.87 outages per year ○ from 1 January 2022 to 31 December 2022: 1.73 outages per year ○ from 1 January 2023 to 31 December 2023: 1.58 outages per year ○ from 1 January 2024 to 31 December 2024: 1.43 outages per year
Incentives	- Bonus (or penalty for negative values) $= €20\text{ million/annual outage} \times \left(\mathrm{FMC}_{\mathrm{Nref}}^{\mathrm{HTA}} - \mathrm{FMC}_{\mathrm{N}}^{\mathrm{HTA}}\right)$ - Payment through CRCP
Implementation date	1 January 2017

3.2. Other follow-up indicators for Enedis's continuity of supply

Before the end of each calendar quarter, Enedis must provide CRE with the following information relating to the previous quarter:

Indicator calculation	Calculation frequency
The sum of outage durations and the number of outages of consumption installations connected in the BT network based on the cause of the outage: • causes related to the public transmission grid (or load shedding); • works in the public distribution grids managed by Enedis; • exceptional events.	Quarterly
For each exceptional event: any element justifying classification as an exceptional event, the sum of outage durations and the number of outages of consumption installations connected in BT due to the event and any element for assessing the rapidity and relevance of the measures taken by Enedis to restore normal operating conditions	Quarterly
The sum of outage durations and the number of outages of consumption installations connected in the HTA network based on the cause of the outage: • causes related to the public transmission grid (or load shedding); • works in the public distribution grids managed by Enedis; • exceptional events.	Quarterly
For each exceptional event: any element justifying classification as an exceptional event, the sum of outage durations and the number of outages of consumption installations connected in HTA due to the event and any element for assessing the rapidity and relevance of the measures taken by Enedis to restore normal operating conditions	Quarterly
The average number per client of voltage excursions[94] for clients with smart meters, by voltage level (BT and HTA)	Quarterly
The average rate of very short outages, less than a second (also called micro-outages), of consumption installations, all causes combined, by voltage level (BT and HTA)	Quarterly
The sum of outage durations and the number of outages of production installations, all causes combined, by voltage level (BT and HTA)	Quarterly

Before the end of the first quarter of each year, Enedis shall also submit to CRE the annual values of the abovementioned indicators as well as the total number of consumption installations connected in the BT range on the one hand, and in the HTA range, on the other hand, as at 31 December the previous year.

4. Local distribution companies serving over 100,000 clients and EDF SEI

This part of the annex outlines the indicators for following the continuity of supply of LDCs serving over 100,000 clients and EDF SEI, defined for TURPE 6 HTA-BT.

This list may be completed for LDCs having opted for the establishment, by CRE on the basis of their accounts, of their contribution to the electricity equalisation fund.

Before the end of first quarter of each year, the LDCs serving over 100,000 clients must provide CRE with the following information relating to the previous year:

[94] A voltage excursion corresponds to a root mean square of BT or HTA voltage, averaged over 10 minutes, lower than 90% of the value of the corresponding nominal voltage or higher than 110% of this nominal voltage.

Indicator calculation	Calculation frequency
The average outage duration of year N in BT ($\mathrm{DMC}_{\mathrm{N}}^{\mathrm{BT}}$), also called B criterion, is defined as the ratio (i) between the duration of long outages (over 3 minutes) of consumption installations connected in BT and (ii) the total number of consumption installations connected in BT as at 31 December of year N.	Quarterly
Average outage duration of year N in HTA ($\mathrm{DMC}_{\mathrm{N}}^{\mathrm{HTA}}$), also called M criterion, is defined as the average duration of long outages (over 3 minutes) of HTA clients weighted by the subscribed power of these same clients as at 31 December of year N.	Quarterly
The average outage frequency of year N in BT ($\mathrm{FMC}_{\mathrm{N}}^{\mathrm{BT}}$), also called F-BT criterion, is defined as the ratio between (i) the number of long (over 3 minutes) and short outages (between 1 second and 3 minutes) of consumption installations connected in BT and (ii) the total number of consumption installations connected in BT as at 31 December of year N.	Quarterly
The average outage frequency of year N in HTA ($\mathrm{FMC}_{\mathrm{N}}^{\mathrm{HTA}}$), also called F-HTA criterion, is defined as the ratio between (i) the number of long (over 3 minutes) and short outages (between 1 second and 3 minutes) of consumption installations connected in HTA and (ii) the total number of consumption installations connected in HTA as at 31 December of year N.	Quarterly

ANNEX 8 – INCENTIVE REGULATION FOR THE QUALITY OF DATA TRANSMISSION

The provisions of the present annex do not preclude DSOs from sending to CRE other indicators which are not explicitly indicated hereafter.

For indicators corresponding to rates, CRE requests each DSO to also send it its calculation details (numerator and denominator).

1. Enedis

1.1. Indicators for the quality of data transmission with financial incentives

1.1.1. Availability rate D+1 of Linky Load Curves

Calculation	Within the scope of points having subscribed to a supplier publication of load curves, number of consumption load curves, in month M, available D+1 in STM / Number of daily load curves to be published in month M
Scope	- All Linky smart meters
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective: o from 1 January 2021 to 31 December 2021: 95.5% o from 1 January 2022 to 31 December 2022: 96% o from 1 January 2023 to 31 December 2023: 96.5% o from 1 January 2024 to 31 December 2024: 97%
Incentives	- The incentive is only in the form of a penalty - €150 k per tenth of a point if the annual rate is below the reference objective - Incentive floor value: - €3 million - Payment through CRCP
Implementation date	1 January 2021

1.1.2. Rate of transmission D+1 of indices and other meter data (before 9.00 a.m.)

Calculation	<u>Number of meter data files, associated with a reference measure point (PRM) with an active subscription (F305A-P305A) containing at least one data, sent from the exchange interface before 9.00 a.m. divided by the number of active subscriptions at the date of publication on PRMs.</u>
Scope	- All points with an F305A-P305A subscription
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective: o from 1 January 2021 to 31 December 2021: 90% o from 1 January 2022 to 31 December 2022: 92% o from 1 January 2023 to 31 December 2023: 94% o from 1 January 2024 to 31 December 2024: 95%
Incentives	- The incentive is only in the form of a penalty - €100 k per tenth of a point if the annual rate is below the reference objective - Incentive floor value: - €2 million - Payment through CRCP
Implementation date	1 January 2021

1.1.3. Rate of successful telemetered readouts for billing for BT > 36 kVA meters

Calculation	Number of real indices[95] used for billing / number of meters to be billed during the month
Scope	- All BT > 36 kVA points equipped with IP boxes
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective: o from 1 January 2021 to 31 December 2021: 97.8% o from 1 January 2022 to 31 December 2022: 98.1% o from 1 January 2023 to 31 December 2023: 98.4% o from 1 January 2024 to 31 December 2024: 98.7%
Incentives	- The incentive is only in the form of a penalty - €100 k per tenth of a point if the annual rate is below the reference objective - Incentive floor value: - €2 million - Payment through CRCP
Implementation date	1 January 2021

1.1.4. Rate of transmission of load curves D+1 for the business market

Calculation	Number of Load Curves, associated with a reference measure point (PRM) with an active subscription (F300b-P300B) containing at least one data, sent from the exchange interface before 9.00 a.m. / Number of active subscriptions on PRMs.
Scope	- All points with an F300b-P300b subscription
Monitoring	- Frequency of calculation: monthly - Frequency of reporting to CRE: quarterly - Frequency of publication: quarterly - Frequency of incentive calculation: annual
Objective	- Reference objective: o from 1 January 2021 to 31 December 2021: 93% o from 1 January 2022 to 31 December 2022: 95% o from 1 January 2023 to 31 December 2023: 96% o from 1 January 2024 to 31 December 2024: 97%
Incentives	- Penalties: -€150 k per tenth of a point if the annual rate is below the reference objective - Bonus: €150 k per tenth of a point if the annual rate is above the reference objective - Incentive floor value: ± €3 million - Payment through CRCP
Implementation date	1 January 2021

1.2. Follow-up indicator for the quality of data transmission

Indicator calculation	Calculation frequency
The rate of periodic intraday transmission of data is calculated as the ratio between the number of responses to admissible requests in less than 30 minutes (F375A), containing data sent to clients from the exchange interface divided by the number of admissible intraday data requests.	Quarterly

[95] The current market rules specify that an index is qualified as real if it is telemetered up to D-5.

ANNEX 9 – DETAILS ON THE ADJUSTMENTS CONCERNING THE INVENTORY OF ELECTRICAL RISERS

This annex lists the non-tariff adjustments adopted by CRE within the framework of the integration of electrical risers (in accordance with the ELAN law) in Enedis's accounts dated 18 December 2020. These non-tariff adjustments correspond to the following corrections to the inventory and valuation of electrical risers:

- consider a quantity of risers identified outside the concession prior to 1966 as already under concession, based on the trend in quantities post 1966;
- take into account a correction for the distribution of riser renovations over the 1958-1992 period;
- consider, for the integration of the ELAN law, an overestimation of risers outside the concession corresponding to at least 15% of the quantities under concession per year before the signing of CdC model 1992 concession contracts;
- ensure similar valuation for risers formerly under concession and outside the concession which present strictly the same operating conditions, within the same technical series.

The non-tariff adjustments resulting from the corrections mentioned above are as follows:

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Adjustment to RAB (in €million)	-141,48	-134,26	-127,22	-120,33	-113,61	-107,07	-100,74	-94,53	-88,44	-82,48
Adjustment to depreciation provisions (in €million)	-7,23	-7,04	-6,89	-6,72	-6,53	-6,33	-6,21	-6,09	-5,97	-5,84
Adjustment to regulated equity (in €million)	-	7,23	14,26	21,16	27,88	34,41	40,74	46,95	53,04	59,01

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Adjustment to RAB (in €million)	-76,64	-70,91	-65,33	-60,00	-54,57	-49,43	-44,60	-40,07	-35,82	-31,84
Adjustment to depreciation provisions (in €million)	-5,73	-5,58	-5,34	-5,42	-5,14	-4,83	-4,53	-4,25	-3,98	-3,73
Adjustment to regulated equity (in €million)	64,85	70,57	76,15	81,49	86,91	92,06	96,89	101,41	105,66	109,64

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Adjustment to RAB (in €million)	-28,11	-24,63	-21,38	-18,38	-15,60	-13,03	-10,68	-8,84	-7,21	-5,80
Adjustment to depreciation provisions (in €million)	-3,48	-3,24	-3,01	-2,78	-2,56	-2,35	-1,84	-1,63	-1,41	-1,18
Adjustment to regulated equity (in €million)	113,38	116,86	120,10	123,11	125,89	128,45	130,80	132,64	134,27	135,68

	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060

Adjustment to RAB (in €million)	-4,62	-3,73	-3,12	-2,70	-2,37	-2,10	-1,87	-1,67	-1,50	-1,34
Adjustment to depreciation provisions (in €million)	-0,89	-0,61	-0,42	-0,34	-0,27	-0,23	-0,20	-0,18	-0,16	-0,15
Adjustment to regulated equity (in €million)	136,86	137,76	138,36	138,78	139,12	139,38	139,61	139,81	139,99	140,15

	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070
Adjustment to RAB (in €million)	-1,19	-1,06	-0,93	-0,83	-0,73	-0,64	-0,56	-0,48	-0,41	-0,34
Adjustment to depreciation provisions (in €million)	-0,13	-0,12	-0,10	-0,10	-0,09	-0,08	-0,08	-0,07	-0,07	-0,06
Adjustment to regulated equity (in €million)	140,29	140,43	140,55	140,65	140,75	140,84	140,92	141,00	141,07	141,14

	2071	2072	2073	2074	2075	2076	2077	2078	2079	2080
Adjustment to RAB (in €million)	-0,28	-0,22	-0,17	-0,12	-0,07	-0,04	-0,02	-0,01	-0,00	-
Adjustment to depreciation provisions (in €million)	-0,06	-0,05	-0,05	-0,04	-0,03	-0,02	-0,01	-0,01	-0,00	-
Adjustment to regulated equity (in €million)	141,20	141,26	141,32	141,37	141,41	141,44	141,46	141,48	141,48	141,48

ANNEX 10 – EVOLUTION OF TURPE 6 HTA-BT BILLS

CRE simulated TURPE bill developments generated by the application of TURPE 6 tariffs as at 1 August 2021. The bill developments calculated take into account the TURPE structure changes implemented as at 1 August 2021 regarding the components for metering, management and withdrawal (including smoothing) as well as the overall change in the tariff level at the same date.

In addition, the simulations made by CRE are done on a representative sample of clients supplied by Enedis for each voltage level. CRE considered that clients' subscribed power was optimised in TURPE 5 and TURPE 6.

1. HTA voltage level

For the HTA voltage level, five representative load curves were built based on the average withdrawals of users distributed by duration of use. These durations of use serve to create groups of users of roughly equivalent sizes.

Representative HTA users	Average duration of use (DU)	Number of HTA users[96]	Bill changes between TURPE 5 and TURPE 6 in 2021
Very short segment: use durations between 0 and 1,000 hours	651	12,274	0.91%
Short segment: use durations between 1,000 and 2,000 hours	1,529	21,415	0.12%
Medium segment: use durations between 2,000 and 3,000 hours	2,470	23,976	1.25%
Long segment: use durations between 3,000 and 4,000 hours	3,457	15,465	0.71%
Very long segment: use durations between 4,000 and 8,760 hours	4,937	18,755	- 0.57%

[96] The number of users is defined based on a representative sample of the HTA user portfolio provided by Enedis.

2. BT > 36 kVA voltage level

For the BT > 36 kVA voltage level, five representative load curves were built based on the average withdrawals of users distributed by duration of use. The durations of use serve to create groups of users representing the following categories:

- Very short segment: seasonal businesses, multi-fluid;
- Short segment: businesses or microenterprises without electric heating;
- Medium segment: Microenterprises with machines operating periodically or businesses with electric heating;
- Long segment: Microenterprises with industrial machines operating regularly;
- Very long segment: Microenterprises with industrial machines operating continuously.

Representative users in BT > 36 kVA	Average duration of use (DU)	Number of users[97]	Bill changes between TURPE 5 and TURPE 6 in 2021
Very short segment: use durations between 0 and 1,000 hours	615	65,655	- 1.37%
Short segment: use durations between 1,000 and 2,000 hours	1,506	127,205	0.20%
Medium segment: use durations between 2,000 and 3,000 hours	2,460	127,206	0.37%
Long segment: use durations between 3,000 and 4,000 hours	3,494	57,448	0.70%
Very long segment: use durations between 4,000 and 8,760 hours	4,661	32,827	0.75%

[97] The number of clients was defined based on a representative sample of the BT > 36 kVA client portfolio provided by Enedis.

3. BT ≤ 36 kVA voltage level

For the BT ≤ 36 kVA voltage level, which comprises the majority of clients connected to the distribution grid, a breakdown by subscribed power and by duration of use was performed in order to identify different categories of representative users.

For each subscribed power level adopted (by increments of 3 kVA between 3 kVA and 12 kVA), three representative load curves were built using the average withdrawals of users whose winter use duration[98] illustrates the following user categories:

- short segment: holiday homes, seasonal rentals, multi-fluid homes;
- medium segment: main residence without electric heating;
- long segment: main residence with electric heating.

Representative users in BT ≤ 36 kVA	Duration of use (DU)	Number of users by subscribed power (thousands)	Annual bill changes between TURPE 5 and TURPE 6 (2021)
Clients with subscribed power of 3 kVA			
Short segment: 0 to 200 hours	87	2,677	+€3.28
Medium segment: 200 to 600 hours	362	3,500	+€2.01
Long segment: over 600 hours	1,054	4,118	- €2.56
Clients with subscribed power of 6 kVA			
Short segment: 0 to 150 hours	78	5,417	+€8.30
Medium segment: 150 to 300 hours	226	7,917	+€6.65
Long segment: over 300 hours	615	7,500	+€3.08
Clients with subscribed power of 9 kVA			
Short segment: 0 to 120 hours	63	817	+€17.15
Medium segment: 120 to 400 hours	228	1,180	+€12.10
Long segment: over 400 hours	670	1,028	+€5.95
Clients with subscribed power of 12 kVA			
Short segment: 0 to 150 hours	77	413	+€22.86
Medium segment: 150 to 400 hours	253	636	+€18.48
Long segment: over 400 hours	718	670	+€9.38

[98] The winter use duration was adopted in BT ≤ 36 kVA in order to distinguish between clients with and without electric heating.

ANNEX 11 – 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[99] 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 local marginal costs into national 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 upstream of their own.

[99] Group of network infrastructure combined 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 withdrawals 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:

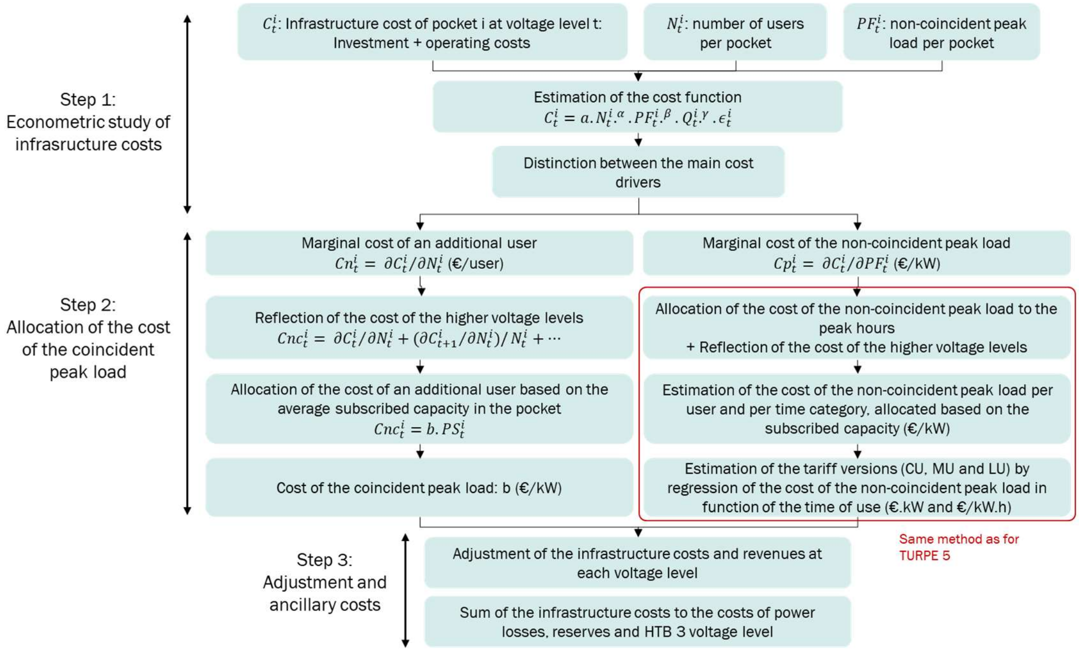

Figure 1 : Steps in the TURPE 6 method

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 level 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:

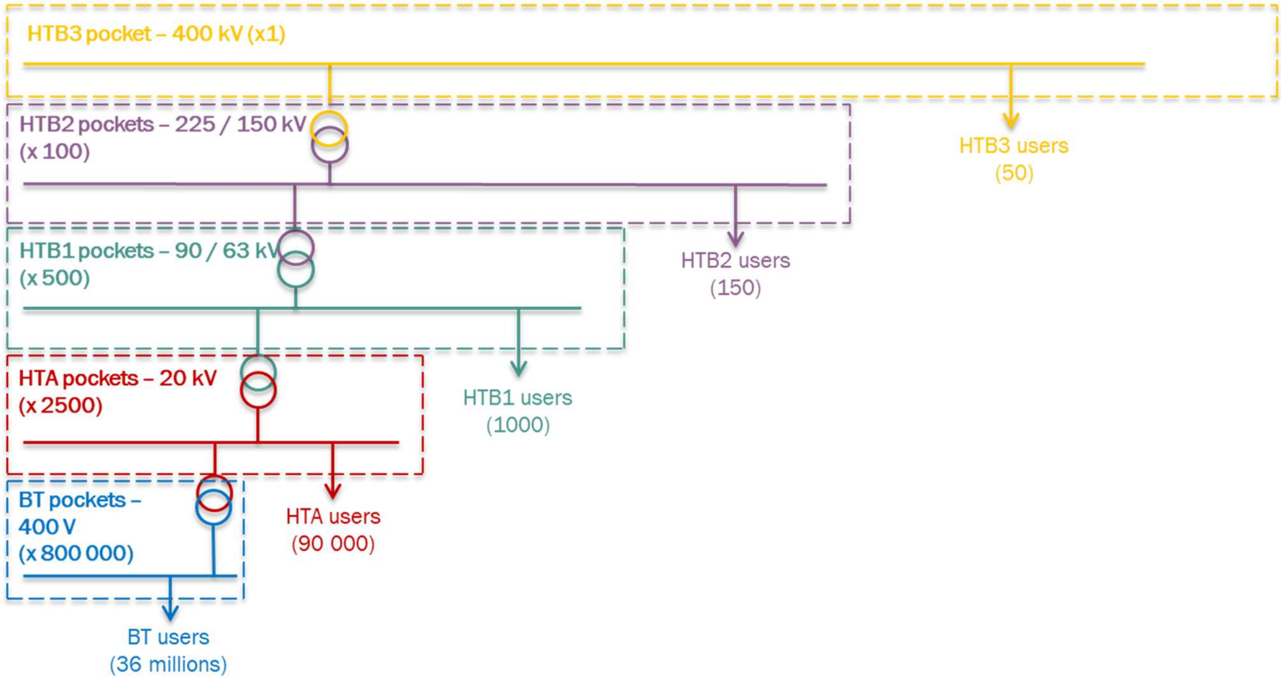

Figure 2 : Breakdown of the grid into pockets (order of magnitude)

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 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.

Tableau 1 : Data considered by pocket in the econometric analysis

Voltage level	Number of pockets	Total cost (€ million)	Maximum asynchronous power (MW)	Number of users or pockets at the lower voltage level	Average cost of Pmax (€/kW)	Average cost per user (€)	Avg. Max. asynchronous power per pocket (MW)	Number of average users per pocket	Average power per user (kW)
HTB2	107	1,420	122,345	879	11.6	1,699,263	1,143	8.2	27,283
HTB1	446	1,794	94,325	3,146	19.0	808,683	211	7.1	20,846
HTA	2143	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[100] 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 non-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 level because of the function they perform as 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.

Tableau 2 : Elasticity of infrastructure costs to the number of users and non-coincident peak load

	Elasticity of the 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.

[100] 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 average power of the 2,500 hours 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 level.

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 to 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 to 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 to 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 to the number of users is obtained, in €/user. This cost takes into account the fact that each customer uses not only the voltage level 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 levels 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 to 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, non-coincident peak load of a pocket refers to the average power withdrawn from the transformer substation during the hours with the highest load demand of the year (2500 hours in MV and 500 hours in LV). 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:

- <u>Representation of the cost generated by a user based on their duration of use</u>

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.

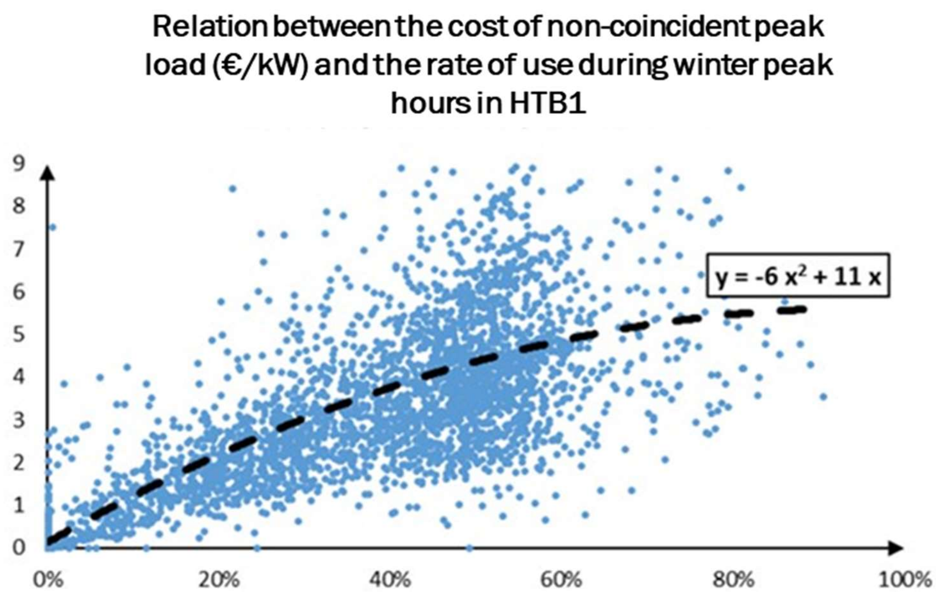

Figure 3 : Infrastructure costs (€/kW maximum power) by user for the peak time category in winter in HTB 1 based on the duration of use at maximum power

To construct these scatter plots, CRE used all of the load curves of users of the HTB voltage level 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.

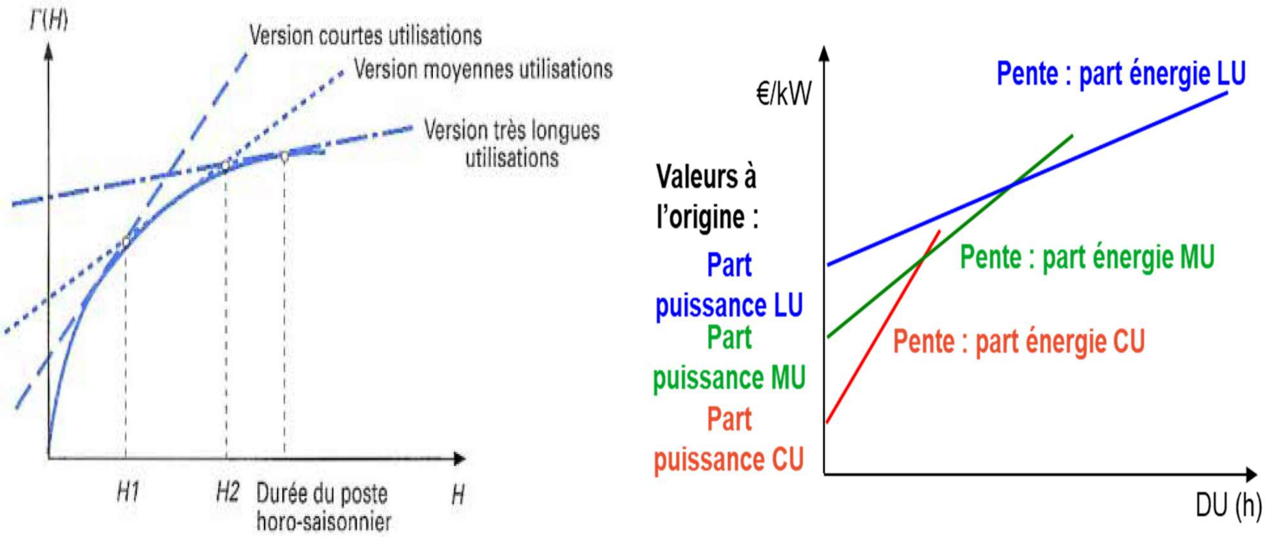

Figure 4 : Approximation of tangents to estimate tariff coefficients (source: Principles of electricity pricing in France by Frédérique Decré and Hervé Chefdeville)

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 level. 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:

Tableau 3 : Rate of power losses compensation by voltage level

Voltage level	Loss rate, including losses of upstream levels
HTB3	1.5%
HTB2	2.0%
HTB1	2.7%
HTA	3.7%
BT	10.1%

Tableau 4 : Unit cost of power losses compensation by voltage level

€c/kWh	Peak times	Winter peak times	Winter off-peak times	Summer peak times	Summer off-peak times
HTB3	0.11	0.10	0.07	0.08	0.05
HTB2	0.15	0.13	0.09	0.11	0.07
HTB1	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

ANNEX 12 – IMPACT OF THE EVOLUTION OF THE WEIGHTING COEFFICIENT FOR THE MONTHLY COMPONENT FOR SUBSCRIBED CAPACITY OVERRUNS (CMDPS) IN THE HTA RANGE ON THE OPTIMISATION OF SUBSCRIBED CAPACITY AND BILL DEVELOPMENTS

Pricing of capacity overruns aims to encourage participants to subscribe the capacity level corresponding to their use, and they thus contribute their fair share to the coverage of the grid costs they generate. Customers can optimise the level of their subscribed capacity by minimising the sum of the amounts related to their fixed portion and to penalties for overruns.

Transmission to CRE, by certain participants, of their load curve within the framework of their response to the public consultation of 8 October 2020 highlighted insufficient adoption by participants, of the possibilities offered by this pricing. However, for sites with the shortest use durations, this subscribed capacity optimisation is essential to optimise their TURPE bill.

The present annex illustrates, for four sites with use durations lower than 1,000 hours, the impact of the drop in the CMDPS on the optimisation of subscribed capacity and the TURPE bill.

Table 76 : Site characteristics

Load curve	Time/season category	Site 1	Site 2	Site 3	Site 4
P max (KW)		5,998	1,262	1,306	1,318
E (kWh)	Peak times	42,083	14,370	66,272	55,021
E (kWh)	Winter peak times	369,083	86,437	277,960	272,448
E (kWh)	Winter off-peak times	149,450	37,806	135,944	140,197
E (kWh)	Summer peak times	839,944	163,323	332,838	400,472
E (kWh)	Summer off-peak times	396,816	80,645	157,299	200,796
DU (h)		300	303	743	811

For each of the sites presented above, bills related to withdrawal were calculated (withdrawal component + overrun penalty)[101] with the CMDPS weighting coefficient at 0.11 (TURPE 5 level) and at 0.04 (value adopted for TURPE 6). For each bill, the capacity subscribed was optimised by minimising the fixed portion and overrun penalty pair.

Results

The results show that the change in the CMDPS weighting coefficient from 0.11 to 0.04 enables subscribed capacity optimisations greater than:

- 50% for sites with use durations of about 300 hours;
- 40% for the site with a use duration of 700 hours;
- 10% for the site with a use duration of over 800 hours.

[101] The bills were calculated using the withdrawal component tariffs, based on the new TURPE 6 methodology but excluding the tariff difference, since this parameter does not influence optimisation of subscribed capacity .

This capacity optimisation reduces the bill related to withdrawal by almost:

- 23% for sites with use durations of about 300 hours;
- 13% for the site with a use duration of 700 hours;
- 3% for the site with a use duration of over 800 hours.

Table 77 : Optimisation of subscribed capacity (SP) and bill development

	Site 1	Site 2	Site 3	Site 4
SP (kW) optimised in T6 with CMDPS at 0.11	5,298	897	895	1,127
SP (kW) optimised in T6 with CMDPS at 0.04	2,126	450	515	979
SP optimisation %	-60%	-50%	-42%	-13%
Bill reduction after optimisation %	-22%	-23%	-13%	-3%

Table 78 : Details in TURPE bills

TURPE items	Site 1	Site 2	Site 3	Site 4
TURPE 6 bill with CMDPS at 0.11 (€)	93,008	19,085	31,872	32,199
Of which fixed portion (€)	*60,351*	*10,218*	*10,194*	*12,835*
Of which Overruns (€)	*7,179*	*2,901*	*2,978*	*811*
Of which energy portion (€)	*25,478*	*5,966*	*18,699*	*18,553*
TURPE 6 bill with CMDPS at 0.04	72,764	14,746	27,796	31,123
Of which fixed portion (€)	*24,217*	*5,127*	*5,866*	*11,151*
Of which Overruns (€)	*23,069*	*3,653*	*3,231*	*1,419*
Of which energy portion (€)	*25,478*	*5,966*	*18,699*	*18,553*

ANNEX 13 – CALCULATION OF THE TRAJECTORY OF EXPENSES RELATED TO CONCESSION FEES (CONFIDENTIAL ANNEX)

This annex is confidential.