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COMMISSION DE RÉGULATION DE L'ÉNERGIE

The Energy Regulation Commission (CRE) consults the market participants.

PUBLIC CONSULTATION NO. 2023-07 OF 26 JULY 2023 RELATING TO THE NEXT TARIFF FOR THE USE OF NATURAL GAS TRANSMISSION NETWORKS OF GRTGAZ AND TERÉGA

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

The provisions of articles L. 452-2 and L. 452-3 of the French Energy Code empower the French Energy Regulatory Commission (CRE) to set the methodology for establishing tariffs for use of the natural gas transmission networks. CRE may make any changes to the regulatory framework and to the level and structure of tariffs that it considers justified, particularly in the light of an analysis of the operators' accounts and of foreseeable changes in operating and investment costs.

The current tariff for use of the GRTgaz and Teréga natural gas transmission networks, known as the ATRT7 tariff, came into force on 1 April 2020 for a period of four years, in accordance with CRE's decision no. 2020-012 of 23 January 2020 on the tariff for use of the GRTgaz and Teréga natural gas transmission networks.

Given the visibility needed by market players and the complexity of the issues to be addressed, and with the aim of conducting a wide-ranging and participatory consultation process on the next gas infrastructure tariffs, CRE organised four thematic workshops open to the public during the first half of 2023:

- the first, on 22 February 2023, concerned the structure of gas distribution tariffs. This workshop provided an opportunity to present the changes envisaged by CRE concerning the introduction of a tariff term billed according to the flow rate of users' meters, in order to take into account the development of back-up distribution uses. This workshop was attended by 75 participants;
- the second, on 4 May 2023, focused on the structure of gas transmission tariffs. This workshop provided an opportunity to present the changes envisaged by CRE concerning the structure of the tariffs for the main transmission network, in particular the tariffs applicable to interconnections. The workshop was attended by 70 participants;
- the third, on 10 May 2023, focused on green gas. This workshop provided an opportunity to present the changes envisaged by CRE concerning the tariffs applicable to the injection of renewable and low-carbon gases into the networks. The workshop was attended by 85 participants;
- the fourth, on 20 June 2023, looked at the future of French gas infrastructures and possible adjustments to the tariff regulatory framework to take account of the decline in natural gas consumption. The workshop provided an opportunity to present the changes envisaged by CRE concerning the depreciation timeline for the Regulated Asset Base (RAB), the inclusion of inflation in the regulated asset base and possible incentives for controlling investment. The workshop was attended by 86 participants.

At the end of each workshop, CRE received written contributions from certain stakeholders. The materials from these workshops, sent to the participants, are published on CRE's website along with this public consultation.

This public consultation presents CRE's preliminary orientations on gas transmission tariffs, based on its analyses and the initial feedback CRE has received from market players, concerning the three main components of its tariff decision scheduled for the end of 2023, to come into force on 1 April 2024:

- the level of costs to be covered and the resulting tariffs;
- the structure of the transmission tariff, i.e. the way in which the allowed revenue of gas transmission system operators (TSOs) is passed on to users through different tariff terms;

- the tariff regulatory framework, which corresponds to a set of multi-year incentive mechanisms designed to ensure that the operator is efficient in terms of cost control and quality of service to users.

CRE is seeking the views of market players on these various issues before making its decision.

At this stage, CRE has not received any energy policy guidelines from the ministers responsible for the economy and energy, as is provided for on an optional basis under the provisions of article L. 452-3 of the Energy Code. However, this public consultation takes into account the guidelines set out in the Multiannual Energy Programme (PPE), which envisages a significant reduction in gas consumption accompanied by an increase in biomethane production, in order to meet France's climate objectives.

Pursuant to Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas (hereinafter "Tariff Network Code"), this public consultation is open for two months and will be sent to the Agency for the Cooperation of Energy Regulators (ACER) for its opinion. It includes all the information required by the Tariff network code.

1. Key issues for the next gas transmission tariffs (ATRT8 tariffs)

The guidelines that CRE will adopt for the ATRT8 tariff will have to meet the challenges of the coming tariff period (2024-2027), but will also have to prepare the regulatory framework for the longer-term issues of the gas system.

The coming tariff period will be marked by the downward trend in natural gas consumption that has already been observed for several years and that the PPE has set, and which has accelerated in 2022 as a result of high prices, energy savings made by gas consumers and the switch by some gas consumers to other forms of energy. In addition, a large number of long-term subscriptions at entry and exit points on the gas transmission system are due to expire between 2024 and 2027, and are unlikely to be renewed in the same proportions. This expected decrease will automatically lead to a reduction in the base on which TSOs collect their revenues. It therefore implies an increase in tariff terms, all other things being equal.

In subsequent tariff periods, the decline in gas consumption is expected to continue. The study on the future of gas infrastructures in 2030 and 2050, published by CRE on 4 April 2023, shows that the size of the necessary infrastructures, particularly for transmission, is likely to decrease only slightly. Significant fixed costs will therefore be borne by a smaller user base, leading to further increases in tariffs.

This outlook leads CRE to consider the changes to the tariff regulatory framework that need to be implemented to guarantee the long-term economic sustainability of the gas system. In particular, CRE is seeking the views of stakeholders on ways to avoid passing on the fixed costs incurred by current infrastructure use to future users. This could involve accelerating the rate of depreciation of operators' RAB and no longer taking inflation into account when revaluing it.

In addition, the current PPE provides for both a trajectory of overall gas consumption reduction, and a gradual change in the energy mix, including in particular the development of gas from renewable sources. The PPE has set a target of 14 to 22 TWh per year of biogas injected into the networks by 2028. The growth seen in recent years, with more than 10 TWh of renewable gas injected by the beginning of 2023, is set to continue, and the TSOs will have to adapt their networks accordingly, which will require specific investment.

In this context of decreasing gas consumption, controlling network operators' costs and investments is a major issue at the heart of the ATRT8 tariff. Network operators are expected to make significant efforts to improve efficiency and effectiveness over the next tariff period.

Tariffs for the use of gas transmission networks, and more broadly all the rules governing access to this network, play a major role in the smooth operation of the wholesale gas market. As France imports most of the gas it consumes, the conditions of access to the French market and its attractiveness are essential. Gas flows on the French transmission system have changed radically since the start of the war in Ukraine. According to the simulations carried out as part of the study on the future of gas infrastructures, this flows configuration is likely to continue in the long term. This public consultation therefore sets out the changes to the tariff structure that CRE considers necessary in this context.

2. Operators' demand

<u>Transmission system operators forecast a sharp decrease in subscriptions</u>

A number of long-term subscriptions for entry and exit at network interconnexion points (IPs) will come to an end during the ATRT8 period. As the actual level of use of the points concerned by these reductions is lower than the level of subscribed capacity, the TSOs anticipate that some of the newly available capacity will not be subscribed when these commitments expire. As a result, they anticipate a significant decrease in the level of capacity subscribed at the interconnection points of GRTgaz and Teréga networks between 2023 and 2027. The planned increases in subscriptions at the LNG terminals will only partially offset this effect.

Furthermore, the overall decline in gas consumption observed in 2022 and which could continue over the next tariff period should, according to the TSOs, lead to a significant decrease in capacity subscriptions on the regional transmission network.

Network operators call for significant additional resources

GRTgaz and Teréga, the natural gas transmission system operators, have each submitted a request for changes in tariffs, setting out their forecast costs for the period 2024-2027. They state that they are faced with the impact of a general rise in costs (inflation), particularly energy prices, as well as increasing obligations in terms of safety and reducing greenhouse gas emissions.

Taking into account the information contained in the tariff applications submitted to CRE by GRTgaz and Teréga would lead to a significant increase in the costs to be covered (net operating costs and normative capital costs):

- approximately €2,217 million/year for GRTgaz over the ATRT8 period, compared with €1,840 million in 2022 (+20%) and ;
- around €302 million/year for Teréga over the ATRT8 period, compared with €249 million in 2022 (+21%).

If accepted by CRE, these requests would lead to a significant tariff increase of around 38% compared with the tariff terms currently in force, given the forecast decrease in consumption.

3. CRE is considering adjustments to network operators' demand in order to control the burden on final consumers.

CRE considers that the allowed revenue trajectories proposed by operators are too high. The sustained decrease in consumption and the decline in capacity subscriptions should lead TSOs to make major efforts to control costs. At this stage, CRE considers that TSOs' controllable expenditure should remain in line, in constant euros, with the levels observed in 2022.

CRE has conducted its own analyses and relied on studies by external consultants, whose reports, which are not binding on CRE, are published at the same time as this public consultation. These reports cover the following subjects:

- an audit of GRTgaz and Teréga's demand for operating costs for the years 2024-2027;
- an audit of the remuneration rate requested for the TSOs' regulated asset base. GRTgaz and Teréga are respectively requesting a weighted average cost of capital of 4.65% and 4.70% (real before tax), compared with 4.25% in the ATRT7 tariff.

At this stage, CRE is considering a smaller increase in tariffs than that requested by the TSOs. The public consultation sets out the ranges within which CRE is currently considering setting the TSOs' allowed revenue for the ATRT8 tariff:

- for operating costs, the adjustments recommended by the external consultant, combined with those envisaged by CRE, constitute the lower limit of the range envisaged, while the TSOs' request constitutes the upper limit;
- for the weighted average cost of capital (WACC), CRE envisages a range of 2.9% to 4.2% (real, before tax, i.e. after deducting inflation - i.e. between 4.4% and 5.5% in nominal terms before tax). The method used to establish this range has changed significantly compared with the ATRT7 tariff (see next point).

With regard to investments, the prospect of decreasing gas consumption increases the importance of their selectivity, with the priority objectives of network security and integrity and the integration of biomethane. At this stage, CRE has not identified any anomalies in the trajectories proposed by the TSOs and therefore does not anticipate any significant adjustments to the TSOs' investment requests. However, CRE will ensure that this expenditure is kept under control when approving the TSOs' annual investments.

CRE plans to change the method used to calculate the weighted average cost of capital to take account of the recent sharp rise in interest rates.

The method used by CRE to determine the weighted average cost of capital is based on a normative WACC structure that ensures a reasonable return on capital invested. It is based on the average of rates observed over the last ten years, which reflects the long lifespan of gas network infrastructure. This method, which has changed very little over the last three tariff periods, has made it possible to maintain the attractiveness of energy infrastructures in France, while taking into account the fall in rates over the last 10 years.

After this long period of decline, interest rates have risen rapidly in the last year or so. The TSOs, like the other gas infrastructure operators, are calling for a change in method to take account of this recent rise in rates when setting the WACC.

At this stage, CRE is considering changing the method for calculating the WACC to take better account of the short-term dynamics of interest rates. To determine the WACC applicable during the ATRT8 tariff, CRE therefore plans to use:

- a rate determined according to the method used for ATRT7 and previous tariffs, based on the analysis of long-term parameters, which could be between 2.7% and 3.9% (real, before tax, i.e. between 3.9% and 5.1% in nominal terms before tax);
- a rate based on more recent economic data, which could be between 3.6% and 5.2% (actual, before tax, i.e. between 6.1% and 7.2% nominal, before tax).

These rates can be applied to old and new assets respectively, or combined in a weighted rate. Assuming a weighting of 80% historical assets and 20% new assets over the tariff period, the average WACC would therefore be between 2.9% and 4.2% (actual, before tax, i.e. after deducting inflation - i.e. between 4.4% and 5.5% in nominal terms before tax).

<u>CRE is considering various ways of controlling the risk of scissor effect</u>

In its study on the future of gas infrastructures, CRE notes that the existing transmission network will still be needed by 2050 (less than 10% of gas transmission infrastructures could be decommissioned or converted to hydrogen), even in scenarios where consumption decreases significantly. At the same time, France's climate objectives call for a reduction in gas consumption (halving or more) and an increase in the production of green gas. In addition to this, the investment needed to integrate green gas could make it very difficult for remaining consumers to cope with the price level.

In this public consultation, CRE presents three measures that could be implemented to reduce the risk of a scissor effect on price level:

- de-indexing TSO RABs to inflation. The purpose of this change is to avoid passing on the cost of current inflation to future network users. This operation is economically neutral over time for TSOs, which would benefit in return from a nominal WACC rate (i.e. including inflation), as is the case for the electricity transmission tariff;
- the implementation of degressive depreciation (which would vary between periods and could therefore be higher in the first few years, then lower);
- reducing certain depreciation periods for long-lived assets whose economic life would be reduced.

CRE plans to implement all or some of these changes, possibly gradually.

<u>CRE presents a tariff structure that takes account of changes in gas flows and the obligations of the European Tariff network code</u>

The structure of the ATRT8 tariff must be set in a transparent and non-discriminatory manner. It must reflect the costs incurred by network users in order to avoid cross-subsidies between categories of users. The ATRT7 tariff already meets the requirements of the Tariff network code.

The ATRT8 tariff envisaged by CRE has been drawn up in such a way as to cover the TSOs' allowed revenue while ensuring that the relative level of the tariff terms is consistent and does not lead to cross-subsidisation between the different categories of transmission system users.

The method used to draw up the tariff grid proposed by CRE is consistent with the ATRT7 tariff. In particular, the unit costs of transit and of supplying national consumers have been aligned, in accordance with the Tariff network code. CRE has adjusted the gas flow scenarios to take account of the major changes observed with the cessation of Russian gas exports to Western Europe and the replacement of these flows by LNG via French LNG terminals or possibly from Spain.

<u>CRE is considering a change in the pricing system for the injection of renewable and low-carbon gas</u>

The development of biomethane production and methanation, coupled with the emergence of new technologies such as pyrogasification and hydrothermal gasification, which are vectors for the decarbonisation of gas, mean that TSOs have to bear the costs of adapting their networks, and producers are becoming a growing category of network users. As a result, CRE is considering increasing the injection tariff to better cover the costs incurred by injection into the network.

<u>CRE presents its preliminary analyses of how the gas transmission tariff could be used to finance R&D in hydrogen and CO_2 transmission.</u>

The TSOs are also asking for a sharp increase in their R&D budgets, which they justify by the need to prepare for the future of their companies and in particular the possible diversification into hydrogen or CO_2 transmission. At this stage of its analyses, CRE is in favour of taking into account the TSOs' R&D budgets, provided that research programmes are coordinated between operators and that the research is linked to the gas transmission activities. At the same time, CRE is supporting the development of the hydrogen and CO_2 capture and storage sectors.

<u>Apart from these changes, CRE envisages a tariff regulatory framework in line with previous tariffs</u>

CRE plans to renew the main mechanisms of the current tariff regulatory framework for the ATRT8 tariff and tariffs for other gas infrastructures: a four-year period, regulation as an incentive to control operating costs and investment expenditure, regulation as an incentive for quality of service, a posteriori coverage of certain discrepancies via the "compte de régularisation des charges et des produits" (CRCP), hereinafter named regulatory account, capping of the annual reconciliation of the CRCP balance.

The results of this regulatory framework, which has been in force for four tariff periods, are generally satisfactory in terms of TSO performance, according to the assessment appended to this public consultation. Nevertheless, CRE is considering adjustments on several issues, such as operators' energy charges, taking account of inflation in annual updates, and incentive regulation applicable to non-network assets.

4. ATRT8 tariff terms set to rise sharply

As a purely illustrative example, taking the middle of the ranges of capital costs and net operating costs presented by CRE in the public consultation, the increase in the various tariff terms could average around 20% between 2023 and 2024, followed by an annual increase in line with inflation. This increase could be smoothed out in part over the four years of the tariff.

Illustrative key figures

Key figures for 2024-2027 (in current €)	Lower limit	Upper limit	2022 actual
Operating expenses M€/year	**954**	**1207**	869
GRTgaz	882	1103	*797*
Teréga	72	104	*72*
Capital expenditure M€/year	**1109**	**1341**	1220
GRTgaz	948	1139	*1043*
Teréga	161	202	*177*
WACC (actual before tax)	**2.9 %**	**4.2 %**	4.25 %
of which historic rate	*2.7 %*	*3.9 %*	*N/A*
of which short-term rates	*3.6 %*	*5.2 %*	*N/A*
WACC (nominal before tax)	4.4 %	5.5 %	5.60 %
of which historic rate	*3.9 %*	*5.1 %*	*N/A*
of which short-term rates	*6.1 %*	*7.2 %*	*N/A*
Investments M€/year	**577**		512
GRTgaz	459		*405*
Teréga	118		*107*

Illustrative tariff 2024			
Main network		**(€/MWh/d/year)**	**Evolution vs. 2023 tariff**
Entries	IP	126.16	19.4 %
	PITTM	119.70	25.8 %
Exits	Obergailbach	436.94	16.3 %
	Oltingue	437.99	13.2 %
	Pirineos	568.34	-3.2 %
	Alveringem	48.46	15.2 %
	Exit to regional network	122.71	28.9 %
Regional network		**(€/MWh/d/year)**	**Evolution vs. 2023 tariff**
Regional network transmission	GRTgaz	98.35	16.7 %
	Teréga	103.19	21.7 %

	2024	2025	2026	2027
Inflation assumptions	2.4 %	1.8 %	1.6 %	1.6 %

Paris, 26 July 2023

For the Energy Regulatory Commission,

The President,

Emmanuelle WARGON

To participate to the consultation process

CRE invites interested parties to submit their contribution by **9 October 2023** at the latest by entering their contribution on the platform set up by CRE: https://consultations.cre.fr/.

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

If your contribution involves elements whose confidentiality you want to preserve, a version concealing these elements must also be sent. In this case, only this version will be published. CRE reserves the right to publish elements that may prove to be essential to the information of all the shareholders, provided that they are not covered by secrets protected by law.

In the absence of a masked version, the full version is published, subject to information relating to secrets protected by law.

Interested parties are invited to respond to the questions justifying their responses.

If you have any questions about the public consultation, please contact CRE at tarifs-infras@cre.fr.

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1. LIST OF QUESTIONS

Tariff regulatory framework

Part 3 of this public consultation (see p.16) presents the tariff regulatory framework currently in force for TSOs, as well as the changes envisaged by CRE for the ATRT8 tariff period.

More specifically, there are questions relating to:

- The main tariff principles (cf. p.17);

Question 1 Do you agree with the conclusions of CRE's review of the regulatory framework?

Question 2 Do you agree with CRE that a four-year tariff period is appropriate for all tariffs? Do you agree with CRE that the mid-period review clause for operating costs should be renewed?

Question 3 Do you have any comments on the method for determining allowed revenue?

Question 4 Are you in favour of changing the method for setting the weighted average cost of capital to better reflect changes in economic conditions? If so, do you favour the introduction of a dual rate or the use of a single weighted rate?

Question 5 If a single rate were to be adopted, on the basis of what weighting do you think this single rate should be established?

Question 6 Are you in favour of maintaining the incentive regulation of transmission system operators' stranded costs?

Question 7 Are you in favour of renewing the regulatory framework for property assets and land sales?

Question 8 Are you in favour of CRE's proposed solution to the treatment of assets sold for conversion to hydrogen?

Question 9 Are you in favour of the main principles for operating and discounting the CRCP as envisaged by CRE?

- The principles of annual tariff changes (cf. p.23);

Question 10 Are you in favour of maintaining the current April-to-April pricing schedule, with the exception of the tariff terms applicable to IPs, which would change on 1 October each year?

Question 11 Are you in favour of the schedule and principles for tariff changes envisaged by CRE for the ATRT8 tariff?

Question 12 Do you have any comments on the changes in the calculation of tariff increases, in particular with regard to the considered adjustment of the CPI term to take account of the difference in inflation between the assumption used and the inflation achieved in N-1? Are you in favour of maintaining the k-factor at +/-2%?

Question 13 Are you in favour of the principle of netting TSO CRCP proposed by Teréga? Are you in favour of the principle of pooling the threshold for clearing TSO CRCP proposed by Teréga?

- The regulatory incentives to control costs (cf. p.25);

Question 14 Are you in favour of maintaining the current regulatory framework for the majority of operating costs?

Question 15 Are you in favour of CRE's position concerning the postponed timetable for setting the regulatory framework and the trajectory of charges relating to the implementation of the future European regulation aimed at reducing methane emissions from the energy sector?

Question 16 Do you agree with CRE's preliminary analysis of the incentive-based regulation of GRTgaz's ANE (Energy Benefit in kind) charges?

Question 17 Are you in favour of the change proposed by GRTgaz to the rate and method of recovery of the costs associated with the congestion absorption mechanisms, the interruptibility mechanism and the surplus revenue from capacity auctions

Question 18 Do you agree with CRE's position that the level of incentives for other operating income and expenses should be maintained?

Question 19 Do you share CRE's view that the energy charge incentive scheme should be reviewed?

Question 20 Do you agree with CRE's position that the cost control incentive mechanism should be renewed for network investments with a budget of more than €20 million?

Question 21 Do you agree with CRE's position that the cost control incentive mechanism should be renewed for network investments other than major projects?

Question 22 Are you in favour of renewing the cost-containment incentive scheme for "non-infrastructure" investments?

Question 23 Are you in favour of harmonising the regulatory framework for Teréga's IT assets with the framework applied to other operators?

- The incentive regulation for commercialisation (cf. p.33);

Question 24 Do you agree with CRE's proposal not to renew the incentive regulation on upstream subscriptions for the next tariff period?

- The incentive regulation for quality of service (cf. p.34);

Question 25 Do you agree with the CRE's and the TSOs' assessment of quality of service over the last four years? Do you have any specific comments or suggestions on incentive regulation of quality of service?

Question 26 Are you in favour of the changes to the incentive regulation system for quality of service envisaged by CRE for the ATRT8 tariff? Are you in favour of adapting the system to take account of issues relating to the injection of renewable and low-carbon gas?

Question 27 Do you agree with CRE's analysis of the possibility of incentive regulation of greenhouse gas emissions?

- The incentive regulation of R&D and innovation (cf. p.39);

Question 28 Do you have any comments on the incentive regulation framework for innovation and R&D envisaged by CRE for the ATRT8 tariff?

- adapting the tariff regulatory framework to limit the risk of an excessive increase in the unit cost of transmission for future network users (cf. p.39);

Question 29 Do you consider that the proposal to end the indexation of the RAB on the inflation and to take it into account directly in the remuneration rate would provide a solution to the risk of an increase in the unit cost of transmission in the long term? Do you have any comments on its implementation (method, progressiveness, etc.)?

Question 30 Do you think that changing the depreciation method would provide a solution to the risk of an increase in the unit cost of transmission over time?

Question 31 Do you agree with CRE's analysis of the usefulness of reducing the depreciation period in response to the risk of an increase in the unit cost of transmission?

Question 32 Do you agree with CRE's analysis of the financial incentive to keep depreciated assets in service?

Question 33 Do you think it would be advisable to implement these changes now?

Question 34 Do you have any other suggestions concerning the distribution of capital costs over time, with a view to meeting the risk of an increase in the unit cost of gas transmission?

Tariff level

Part 4 of this public consultation (see p.45) presents the operators' tariff requests, the results of the audits on net operating costs and the rate of remuneration, and CRE's preliminary adjustments concerning the level of TSO costs to be covered for the ATRT8 period.

Question 35 Do you agree with CRE's orientations on the R&D themes to be included in TSO load trajectories?

Question 36 Do you have any comments on the level of costs to be covered requested by GRTgaz and Teréga?

Question 37 Are you in favour of the orientations envisaged by CRE concerning the level of costs to be covered for the ATRT8 period for GRTgaz and Teréga?

Question 38 Do you have any comments on the projected subscriptions envisaged by CRE for the period 2024-2027?

Tariff structure

Part 5 of this public consultation (see p.74) sets out CRE's proposed orientations for the structure for the ATRT8 tariff period.

In particular, there are questions on:

- the main network tariff structure (see p.75). These questions mainly relate to the application of Regulation (EU) 2017/460 (network code Tariff);

Question 39 Are you in favour of maintaining the classification of services provided by the TSOs in the ATRT8?

Question 40 Are you in favour of the distribution of main network and regional network cost, as well as the storage compensation envisaged by CRE in the ATRT8?

Question 41 Are you in favour of maintaining the balance between costs and income for the main and regional networks in the ATRT8?

Question 42 Are you in favour of maintaining the principle of 100% capacity-based pricing for ATRT8?

Question 43 Are you in favour of maintaining the entry-exit pricing system for ATRT8?

Question 44 Are you in favour of maintaining the harmonisation of main network tariff terms for ATRT8?

Question 45 Are you in favour of abolishing the 100% discount on the North East and Atlantic PITS tariffs from 1 April 2024?

Question 46 Are you in favour of maintaining the 34/66 entry/exit income ratio for ATRT8?

Question 47 Do you have any comments on the flow scenarios envisaged at this stage by CRE?

Question 48 Do you have any comments on the methodology for calculating reference prices envisaged at this stage by CRE?

Question 49 Do you have any comments on the consistency of unit costs for the various transit routes and for supplying domestic customers?

Question 50 Are you in favour of maintaining the pricing principles for the Virtualys exit point for ATRT8?

Question 51 Are you in favour of CRE's positions regarding the level of multipliers?

Question 52 Are you in favour of supressing congestion tariffs?

Question 53 Do you have any comments on the tariff grid presented by CRE? In particular, do you think it would be preferable to smooth out the planned increase at the beginning of the tariff period?

Question 54 Are you in favour of Teréga's request to change the discount on interruptible capacity at the Pirineos IP?

Question 55 Are you in favour of the CRE's orientations for pricing interruptible capacity for GRTgaz and Teréga?

Question 56 Are you in favour of the orientations envisaged by the CRE concerning the pricing of back-haul capacity for GRTgaz?

Question 57 Are you in favour of the tariffs for the use of virtual backhaul capacity at the PITTM envisaged by CRE?

- the regional network tariff structure and the tariff for injecting renewable and low-carbon gas (see p.90);

Question 58 Do you share CRE's position on maintaining the principles of regional network pricing?

Question 59 Do you share CRE's position on coefficients for intra-annual capacity?

Question 60 Do you share CRE's position on the pricing of exceeding capacity penalties?

Question 61 Are you in favour of maintaining the principle of an injection charge and extending it to renewable and low-carbon gas production facilities?

Question 62 Are you in favour of the principles, construction parameters and levels of the injection charge envisaged by CRE for ATRT8? Are you in favour of extending the scope of costs to be covered by the injection charge? Do you have any other suggestions concerning this scope of costs and the form to be given to the injection charge?

Question 63 Are you in favour of the principle of transferring to the TSOs the revenue received from the injection charge by the DSOs and associated with the operation of the backhauls and the TSOs' indirect operating costs?

Question 64 Do you have any comments on the tariff grid presented by CRE? In particular, do you think it would be preferable to smooth out the planned increase at the beginning of the tariff period?

Storage compensation

Part 6 of this public consultation (see p.99) sets out the general principles and results of storage compensation, as well as the direction envisaged by CRE for the ATRT8 tariff period.

Question 65 Are you in favour of renewing the storage compensation modalities?

Others

Question 66 Do you have any other comments?

2. CONTEXT AND OBJECTIVES OF THE PUBLIC CONSULTATION

2.1 CRE's powers

The provisions of article L. 134-2, 4° of the French energy code empower CRE to specify the "*conditions for the use of natural gas transmission and distribution networks [...], including the methodology for establishing the tariffs for the use of these networks [...] and tariff evolutions [...]*".

The provisions of articles L.452-2 and L.452-3 of the French Energy Code provide a framework for CRE's powers in terms of tariffs.

The provisions of article L. 452-1 state in particular that these tariffs *"are established in a transparent and non-discriminatory manner to cover all costs borne by the transmission network operators and the storage infrastructure operators [...], insofar as these costs correspond to those of efficient operators. These costs take into account the characteristics of the service rendered and the costs related to this service, and include the obligations established by law and regulations as well as those costs resulting from the execution of public service missions and contracts mentioned in I of Article L. 121-46"*.

The provisions of article L. 452-2 state that CRE shall define the methods used to set the tariffs for the use of natural gas networks.

In addition, the provisions of article L. 452-3 state that CRE shall deliberate on changes to the tariff *"with, where applicable, the modifications to the level and structure of the tariff that it deems justified in view, in particular, of the analysis of the operators' accounts and any forecast changes in operating and investment expenses"*. CRE's deliberation may provide for a *"multi-annual framework for the changes in tariffs as well as appropriate short- or long-term incentive measures to encourage operators to improve their performance related in particular, to the quality of service provided, integration of the internal gas market, the security of supply and productivity efforts*".

The provisions of article L. 452-3 also specify that CRE shall "*consult energy market participants, based on the modalities that it determines*".

2.2 Purpose of the consultation

The current tariff for transmission system operators (ATRT7) covers the period 2020-2023. CRE is consulting on the next tariff, planned for the period 2024-2027.

CRE is seeking the views of market players on the orientations it envisages for the ATRT8 tariff, as regards the regulatory framework, the level of charges to be covered and the structure of the tariff.

Some elements of the regulatory framework are also intended to apply to storage and distribution tariffs: these are also presented in public consultation no. 2023-06 concerning the ATS3 tariff of 26 July 2023, and the public consultation concerning the ATRD7 tariff, which will be published in Autumn 2023.

While CRE plans to maintain most of the principles in force in the ATRT7 tariff in the ATRT8 tariff, the changes envisaged for the next ATRT8 tariff are intended to:

- adapt the tariff regulation to France's energy policy objectives and their consequences for the use of gas infrastructures in the medium term;
- establish a regulatory framework that will encourage operators to control their costs and improve the quality of service provided to their users;
- adapt the structure of the tariff to the reduction in long-term subscriptions at interconnection points and to changes in demand and supply patterns observed from 2022 onwards, while ensuring that the tariff complies with the requirements of European network codes, in particular the Tariff network code.

3. TARIFF REGULATORY FRAMEWORK

3.1 The current tariff regulatory framework has enabled cost control over the long term and improve the quality of service and supply

The main principles of the tariff framework for gas and electricity networks and infrastructures have remained stable for more than 10 years, with three main objectives:

- to encourage infrastructure operators to control their costs in order to limit the impact of infrastructure tariffs on end consumers;
- to enable operators to finance investment in infrastructure;
- to aim for a high level of service and supply quality.

To achieve this, it relies on financial mechanisms designed to encourage infrastructure operators to seek efficiency over the long term. A four-year tariff period and the principle of multi-year financial incentives for costs and quality of service have been introduced. The regulatory framework leaves a great deal of freedom in the management of each of the infrastructure operators, enabling them to seek the most appropriate improvements in performance.

CRE makes a positive assessment of this framework, which has made it possible to control costs over the long term while improving quality of service. The framework has also proved highly resilient in the face of two major crises - the covid crisis[1] and the energy price crisis - by giving operators the means to ensure business continuity under good conditions.

In the light of this assessment (see detailed assessment in appendix), CRE plans to renew most of the current framework for the next generation of tariffs, but to modify a few mechanisms, in particular to take better account of current economic conditions (inflation, energy prices) and the specific context of reduced gas consumption.

3.1.1 Controlling costs to limit the impact of tariffs on end consumers

The regulatory framework provides for different incentive regulation for net operating costs and capital costs.

With regard to operating costs, the regulatory framework provides for a cost trajectory over the four years of the tariff period. Deviations from the trajectory are borne (or benefited) by the operators, except for a few selected items that are more difficult to predict and control, for which all or part of the deviation is covered by the tariffs via the CRCP (Compte de Régulation des Charges et des Produits, hereinafter “Regulatory Account”). Operators are thus encouraged to improve their efficiency over the period. CRE is committed to ensuring that the level of efficiency revealed during the tariff period is taken into account when setting subsequent tariffs, so that infrastructure users benefit from productivity gains over time. To achieve this, the operating cost trajectories set for a new tariff period are based on the expenditure levels achieved by operators over the previous period.

CRE considers that this framework has made it possible to control the operators' expenditure over the long term: over the last ten years, the level of the gas operators' net operating costs has been kept under control (close to inflation), while their infrastructures have expanded considerably. In addition, the scope of the CRCP and its sizing have proved to be well suited to protecting regulated infrastructure operators from the effects of the health crisis and the energy price crisis. During the tariff period, CRE had the framework for energy costs revised[2] to take better account of rising prices and the volatility of the energy markets.

With regard to investments and capital costs, the regulatory framework provides that deviations from the trajectory are borne by the tariff and not by the operators. CRE considers that this method has enabled regulated operators to make all the investments necessary to carry out their missions in recent years. In addition, incentive regulation mechanisms (target budgets for major projects, unit costs, off-grid investment, etc.) have made it possible to control investment costs without restricting volumes (see section 3.3.2).

As decisions to invest in networks have long-term pricing implications, CRE considers that controlling these costs is more than ever a priority for both gas and electricity. This is particularly the case for gas, given the prospects for a long-term decline in gas consumption and the phasing out of fossil fuels.

3.1.2 Enabling infrastructure operators to finance investments

The tariff regulation framework must guarantee a reasonable return on invested capital that enables the regulated assets to be financed, while at the same time providing a fair signal for investment in the energy transition and keeping facilities in operation. In this respect, the level of remuneration paid to the operator must, on the one hand, enable it to finance the interest charges on its debt and, on the other hand, provide it with a return on equity that is consistent with the level of risk associated with comparable assets.

[1] Deliberation of 25 March 2021 on the effects for 2020 of the COVID-19 crisis for network operators

[2] Deliberation of 31 January 2023 on the annual change in the tariff for use of the GRTgaz and Teréga natural gas transmission networks from 1 April 2023

During previous tariff periods, the rate of return, or weighted average cost of capital (WACC), was applied to the Regulated Asset Base (RAB), which aggregates the value of all the assets operated by the same operator. It was set for the entire duration of the tariff period and calculated on the basis of calculation parameters derived from long-term data. In particular, the risk-free rate has been calculated on the basis of long-term averages of long-maturity rates, in line with the long-life assets that make up the RAB.

The use of long-term averages to set remuneration rates for regulated infrastructure operators seems appropriate for these activities, which are characterised by long-term investments. However, it raises the question of how to finance these investments. Indeed, these long-term averages can diverge significantly from the rates observed on the market at the time when operators can obtain financing. This is currently the case with the recent rise in interest rates, which has led CRE to propose amending the existing framework on this point.

3.1.3 Aiming for a high level of service and supply quality

Quality of service, including continuity of supply, is a major concern for infrastructure users. Incentive regulation of service quality is one of the pillars of the regulatory framework defined by CRE, which ensures that economic efficiency is not achieved at the expense of the services provided by these infrastructures.

Improving incentives for quality of service and supply is an ongoing process. The relevance and usefulness of incentives must be regularly reviewed to ensure that they meet the needs of infrastructure users.

Most of the quality of service indicators subject to financial incentives operate on a bonus/malus basis. For each indicator, targets, corresponding to the performance deemed desirable and reasonable for the item concerned, are defined by CRE and revised regularly. If the target is exceeded, a bonus is paid and, conversely, a penalty if the actual performance is below the target set by CRE. Both bonuses and penalties are capped. Payments are made via the CRCP (regulatory account).

Overall, the quality of service provided by natural gas TSOs has remained at a high level for both incentivised and non-incentivised indicators, particularly in terms of the quality of data transmitted to market players. These results confirm the increase in results from the previous period. For the next period, CRE plans to introduce new indicators specific to the injection of biomethane into the networks.

A detailed report on the quality of service provided by gas transmission system operators is presented in a dedicated section of this consultation (section 3.5).

Q1 : Do you agree with the conclusions of CRE's review of the regulatory framework?

3.2 Main tariff principles

The ATRT8 tariff is based on the definition, for the coming tariff period, of an allowed revenue trajectory for each TSO and forecast capacity subscriptions on their respective networks.

The ATRT8 tariff will also establish a regulatory framework to limit the financial risk of TSOs and/or users for certain predefined cost or revenue items, through a regulatory account (CRCP), and to encourage TSOs to improve their performance through incentive mechanisms.

All these elements will be taken into account to establish the tariff applicable for 2024 and the terms and conditions for its annual evolution.

3.2.1 A tariff period of about four years

The length of the tariff periods applied to all regulated infrastructures has been harmonised at four years.

CRE plans to maintain the duration of the tariff period at four years for the next generation of tariffs for the use of regulated infrastructures. In particular, CRE considers that this period provides the market with visibility on changes in infrastructure tariffs and gives operators the time they need to make productivity improvements.

In order to take into account the consequences of any major legislative or regulatory changes that may occur during this period, CRE plans to renew the review clause currently in force in the ATRT7 tariff into the ATRT8 tariff : thus, the possible consequences of new legislative or regulatory provisions or of a court or quasi-judicial decision could give rise to a re-examination of the tariff trajectory for the last two years of the tariff period if the level of net operating costs used in the ATRT8 tariff is modified by at least 1%.

Q2 : Do you agree with CRE that a four-year tariff period is appropriate for all tariffs? Do you agree with CRE that the mid-period review clause for operating costs should be renewed?

3.2.2 Determining the allowed revenue

The TSOs' forecast allowed revenue is made up of the forecast net operating expenses (NOE), the forecast normative capital expenses (NCE), the reconciliation of the balance of the regulatory account (CRCP), the forecast inter-operator financial compensation (INT) between GRTgaz and Teréga, and a smoothing term (LIS):

$$RA = NOE + NCE + CRCP + INT + LIS$$

Where:

- RA: forecast allowed revenue for the period;
- NOE: forecast net operating expenses for the period (cf. 3.2.2.1);
- NCE: forecast normative capital expenses for the period (cf. 3.2.2.2);
- CRCP: reconciliation of the regulatory account (cf. 3.2.2.3);
- INT: inter-operator financial compensation mechanism (cf. 3.2.2.4);
- LIS : smoothing term (cf 3.2.2.4).

The tariff framework makes it possible to guarantee the collection of allowed revenue.

CRE has no plans to change the elements to be taken into account in allowed revenue.

3.2.2.1 Net operating expenses

The net operating expenses (NOE) are defined as the gross operating expenses, from which the operating income is deducted (own work capitalised and the extra-tariff income in particular).

The gross operating expenses consist mainly of energy costs, operation and maintenance of the network costs, external consumption, staff expenses and taxes.

The level of the net operating expenses retained is determined from all the required costs involved in the TSO's activity to the extent that, pursuant to Article L. 452-1 of the French Energy Code, these costs correspond to those of an efficient system operator.

3.2.2.2 Normative capital expenses

Normative capital expenses (NCE) include the return on and depreciation of fixed capital. The calculation of these two components is based on the valuation and development of assets operated by GRTgaz and Teréga – the regulatory asset base (RAB) – and assets under construction (AuC), i.e. investments made that have not led yet to the commissioning of assets.

The NCE correspond to the sum of the depreciation of the assets making up the RAB and the remuneration of capitalised assets. The latter corresponds to the product of the value of the RAB by the rate of return determined on the basis of the evaluation of the weighted average cost of capital (WACC) and to the product of the value of the AuC by the cost of debt.

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

The method adopted to set the rate of return on assets is based on the WACC with a normative financial structure. Indeed, the TSO's return should, in fact, firstly enable it to service the interest payments on its borrowing, and secondly provide its shareholders an equity comparable to that which it could obtain from investments elsewhere entailing a comparable level of risk. This cost of equity is estimated using the methodology known as the capital asset pricing model (CAPM).

In its tariff file for ATRT8, GRTgaz asks that the AuC be remunerated at the WACC and no longer at the cost of debt. CRE is not in favour of this, as it would remove the strong incentive for operators to commission assets, as the cost of debt is lower than the WACC (see detailed analysis in section 3.2.2.2.2).

CRE is not planning to modify the RAB's calculation principles and plans to renew the procedures currently in force.

> Q3 : Do you have any comments on the method for determining allowed revenue?

3.2.2.2.1 Evolution of RAB

<u>Terms and conditions for changes in the regulated asset base in current tariffs</u>

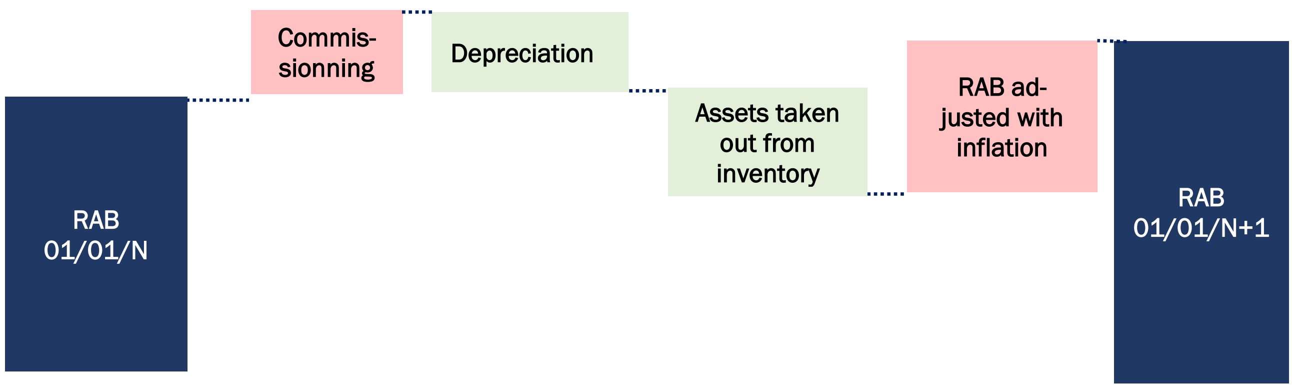
The Regulated Asset Base (RAB) represents the sum of the operator's tangible and intangible fixed assets (valued at 1 January each year):

- RAB increases when an asset is brought into service;
- RAB decreases as assets are depreciated, or if an asset is scrapped or sold.

Under the regulatory framework applied to the gas transmission networks over the ATRT7 period, the assets included in the RAB are revalued each year in line with inflation. For this reason, CRE has used a real WACC that does not include inflation for previous tariff periods.

In section 3.7.4 of the public consultation, CRE asks stakeholders about the most appropriate way of taking inflation into account in the TSOs' normative capital charges.

Evolution factors of the RAB under the current regulatory framework



Commissionning

The contractual date on which assets are included in the RAB is 1 January of the year following their entry into service.

Depreciation of assets

Under the current framework, assets are depreciated on a straight-line basis over their economic life (the straight-line depreciation method is described in section 3.7.5). Land is stated at its historical value, revalued and not depreciated.

The useful lives adopted by CRE for the main categories of assets are as follows:

Types of assets	Normative lifetime
Pipes and connections	50 years
Delivery, pressure reduction and metering stations	30 years
Compression	30 years
Other auxiliary installations	10 years
Buildings	30 years

Assets removed from the inventory

Assets scrapped or disposed of before the end of their economic life are removed from the RAB and do not give rise to depreciation or remuneration. The tariff treatment of assets removed from the inventory is detailed in section 3.2.2.2.3.

Revaluation of RAB

Assets are currently revalued at 1 January each year by the July-to-July inflation rate. The revaluation index used is the 1763852 consumer price index excluding tobacco, for all households resident in France.

3.2.2.2.2 Return on assets

The method used to set the rate of return on assets is based on the WACC for a normative financial structure. The TSO's level of remuneration must enable it to finance the interest charges on its debt and provide its shareholders with a return on equity comparable to that which they could obtain for investments involving comparable levels of risk. This cost of equity is estimated on the basis of the "Capital Asset Pricing Model" (CAPM) methodology.

In previous ATRT tariff deliberations, CRE set a single rate of return that applies throughout the tariff period to all the assets making up each operator's RAB, regardless of when they were commissioned. This single rate is calculated on the basis of the observed average of various parameters over the last ten years, reflecting the long lifespan of gas network infrastructure.

Because long-term averages are used, the rate of remuneration evolves with considerable inertia in relation to changes in market rates. This method, which has changed very little over the last three tariff periods, has made it possible to maintain the attractiveness of energy infrastructures in France, while taking into account the fall in rates over the last 10 years. It is also consistent with the fact that operators' average financing costs also evolve with a certain inertia (asset financing is managed globally, with long-term debt refinanced only in part during a single tariff period).

Nevertheless, the current economic context is leading to a rise in interest rates, which will only be partially taken into account in the long-term averages: this is leading operators to request that the remuneration should better reflect the sudden changes in current market conditions.

CRE has examined the capacity of the current system to remunerate new assets in a manner consistent with this new environment, and is considering, for the ATRT8 period, a change in the remuneration method to better reflect current conditions. At this stage, CRE is considering introducing a distinction between, on the one hand, a long-term rate, the terms of which would remain unchanged (i.e. a rate calculated on the basis of averages over the last ten years) and, on the other hand, a short-term rate based on shorter-term data. While such a change in method would lead to greater volatility in capital charges, it would make it possible to set operators' remuneration at a level more in line with the capital costs expected over the next few years to finance new investments.

CRE recalls that, during the public consultations held in 2019 to prepare the ATRT7, ATRD6 and ATS2 tariffs, it asked market players about a similar proposal in a context of falling interest rates, which would have enabled consumers to benefit more quickly from improved financing conditions. Some of the participants, and in particular the infrastructure operators and their shareholders, were against using short-term values, which they considered too complex and difficult to understand.

Short-term data could be used, for example, by allocating the long-term rate to historical assets and the short-term rate to new assets:

- the remuneration rate applied to new assets would apply, for example, throughout the ATRT8 tariff period;
- for the ATRT8 tariff period, under current financing conditions, this rate could be 200 bps to 250 bps higher than the remuneration rate derived from long-term data;
- finally, after this period of, for example, 4 years, the assets concerned would be included in the RAB of historical assets and remunerated at the long-term rate.

Short-term data could also be taken into account by applying a weighted average of these two rates to the entire asset base: the weighting could, for example, reflect the same weighting of historical assets and new assets. While this option is simple, it is less flexible because it cannot be adapted to the actual investment volume of each operator.

Q4 : Are you in favour of changing the method for setting the weighted average cost of capital to better reflect changes in economic conditions? If so, do you favour the introduction of a dual rate or the use of a single weighted rate?

Q5 : If a single rate were to be adopted, on the basis of what weighting do you think this single rate should be established?

3.2.2.2.3 Processing of assets taken out of the inventory

Processing of stranded assets

By "*stranded costs*", CRE means the residual book value of assets withdrawn from the inventory before the end of their economical life, as well as expenses relating to technical studies and upstream steps that could not be capitalised if the projects were not carried out.

Under the ATRT7 tariff framework, stranded costs are treated as follows, on presentation of the files by the operators:

- recurring and predictable stranded costs are subject of a tariff trajectory with fixing of an annual envelope;
- sunk study costs for major projects having previously been approved by CRE are covered by the tariff via the CRCP;

- the coverage of other stranded costs are examined by CRE on a case-by-case basis, based on justified files presented by the TSOs.

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

CRE's preliminary analysis of the tariff treatment of stranded assets

CRE considers that the current regulatory framework is well adapted. It ensures that the TSOs' recurring stranded costs are covered via an incentive-based trajectory, and that exceptional stranded costs are covered on a case-by-case basis, depending on the efficiency of the costs presented by the operators.

Furthermore, the TSOs are not requesting any changes to this regulatory framework.

At this stage, CRE therefore plans to make no changes to the regulatory framework for stranded costs for ATRT8.

Q6 : Are you in favour of maintaining the incentive regulation of transmission system operators' stranded costs?

Processing of sold assets

When an asset is sold by an operator, it leaves its capital, exits the RAB and ceases, in fact, to generate capital expenses (depreciation and remuneration). This transfer can also generate added value for the operator (difference between the transfer price and the net book value).

Property and land assets

Under the tariff framework set out in the ATRT7 tariff, in the event of the sale of property asset or land asset:

- if the disposal gives rise to an accounting gain, 80% of the proceeds from the disposal, net of the net book value of the asset sold, is included in the CRCP so that network users benefit from most of the gains from the resale of these assets, insofar as these users have borne the acquisition costs (the operators' allowed revenue covers the annual depreciation and remuneration of the RAB assets), while preserving an incentive for the operator to maximise this gain. The operator retains the remaining 20% of the gain;
- any sale giving rise to an accounting loss is examined by CRE, on the basis of a substantiated case presented by the operator.

CRE's preliminary analysis of the tariff treatment of sold assets

CRE considers that this framework for regulating assets sold is well suited. The inclusion in the tariff of capital gains on the sale is justified, given that the tariff has helped to finance the assets sold.

During the ATRT7, this regulatory framework was applied for Teréga, following the sale of several buildings as part of the operator's site reorganisation project.

At this stage, CRE therefore plans to maintain the regulatory framework provided in ATRT7 for the property and land assets sold.

Q7 : Are you in favour of renewing the regulatory framework for property assets and land sales?

Processing of assets converted to hydrogen

European targets for reducing greenhouse gas emissions could eventually lead to the development of a hydrogen transmission network. In this context, some of the gas transmission network's infrastructure could be converted and reused to transport hydrogen.

Converting a gas transmission network asset to hydrogen implies removing the asset from the RAB of the operator that operates it, and transferring it to another operator (or another asset base if it is the same operator, whether the hydrogen transmission activity is regulated or not). This raises the question of the transfer price of the assets concerned, and how any capital gain is to be shared between the operator and the network users.

The European framework for the hydrogen market has not yet been defined at this stage: on 15 December 2021, the European Commission published a legislative proposal revising the European Union's rules on access to the gas market and networks, which includes arrangements to facilitate the development of the hydrogen market. This legislative proposal is under discussion and has not yet been adopted. In its current version, the proposal provides for ACER to publish recommendations concerning the valuation of gas assets converted to hydrogen.

The ATRT7 tariff does not provide for a specific regulatory framework for assets that would be sold with a view to conversion to hydrogen. Although no cases of conversion during the next tariff period have been identified at this stage among TSO assets, it is not possible to completely rule out the possibility that the situation may arise in the future.

CRE's preliminary analysis of the tariff treatment of assets converted to hydrogen

In the absence of a European framework in force, and given the lack of anticipated cases of conversion envisaged by the TSOs for the coming tariff period, CRE plans at this stage to deal with assets sold with a view to conversion to hydrogen on a case-by-case basis, on the basis of substantiated cases presented by the TSOs. CRE will be careful to ensure that the sale price is set in such a way as to avoid cross-subsidies between gas and hydrogen network users, and that any accounting gain is shared appropriately between TSOs and users. In the event that future hydrogen transport networks are regulated, CRE will also ensure that their future users do not have to cover costs already covered by the previous gas users.

Q8 : Are you in favour of CRE's proposed solution to the treatment of assets sold for conversion to hydrogen?

3.2.2.1 Principle of the CRCP

<u>Calculation and reconciliation</u>

The level of the ATRT tariff is set by CRE based on hypotheses on the forecast level of charges and subscription revenues. A *post hoc* adjustment mechanism, the regulatory account (CRCP), was introduced in order to take into account all or part of the differences between the expenses and income actually observed, and the forecast expenses and income, for identified items (see section 2.3.2). The CRCP is also used for the payment of financial incentives resulting from the application of incentive regulation mechanisms.

Calculated at 31 December of each year N, the CRCP is cleared within the limit of an annual tariff increase of +/- 2%. If this limit is reached and does not allow the CRCP balance to be fully cleared within the tariff increase for year N+1, the balance not cleared during year N+1 is carried forward to year N+2. In addition, the balance of the CRCP recorded at the end of the tariff period is taken into account when establishing the allowed revenue for the following period. The CRCP balance is therefore reset to zero at the beginning of each tariff period.

The +/- 2% cap has been used for several periods in most electricity and gas network tariffs, as it gives market players good visibility of the trajectory of tariffs over the four-year tariff period. It has worked without difficulty for more than 10 years.

However, the gas crisis at the end of the tariff period led to a very high CRCP for some operators (such as GRDF), due in particular to the rise in energy prices, inflation and the decrease in gas consumption. This observation has led operators, and GRDF in particular, to request a review of the clearance procedures during the annual changes: these requests and CRE's preliminary orientations are set out in section 3.2.2.4 of this consultation.

<u>Financial neutrality of the system</u>

To ensure the financial neutrality of the mechanism, the balance of the CRCP at 1 January of year N+1 is obtained by discounting the balance of the CRCP at 31 December of year N. Since the introduction of the CRCP mechanism in ATRD3, ATS1 and ATRT3, this discount rate has been defined as the risk-free rate.

Due to a large forecast CRCP balance at the end of the period, several operators are requesting a change in this parameter. GRDF is asking for the discount rate to correspond to the nominal WACC before tax or the nominal cost of debt, as it considers that it will have to bear financing costs while waiting for the CRCP to be cleared. Teréga is asking for a discount rate of 3.30%, including a risk-free rate and a "comfort premium", which is a specific adjustment to the yield on government bonds.

CRE points out that the return of the CRCP balance is always guaranteed, regardless of its level. Moreover, it is returned to the operator in the relatively short term. The level of long-term risk included in the level of the WACC or the cost of debt is not relevant for discounting the balance of the CRCP. CRE therefore considers that the risk-free rate remains the relevant parameter for discounting the balance of the CRCP. Nevertheless, as part of the remuneration of assets (see section 3.2.2.2.2), CRE is considering a new method for determining the WACC, taking into account a risk-free rate based on historical parameters and a risk-free rate based on short-term data, which could be applied respectively to assets already in service and to new assets. If this method of remunerating assets were to be adopted, CRE would consider using the risk-free rate applied to new assets to discount the balance of the CRCP.

Q9 : Are you in favour of the main principles for operating and discounting the CRCP as envisaged by CRE?

Inter-operator financial compensation mechanism

Finally, to ensure a balance between the allowed revenue and the tariff revenues of each TSO, the ATRT7 tariff provided for a compensation flow between GRTgaz and Teréga in respect of the annual national change in the tariff terms of the main transmission system.

As part of the annual change in the ATRT7 tariff, a $k_{national}$ coefficient is calculated to determine the annual change in the main transmission system tariff terms (see section 3.2.2.4). This results in an opposite difference in revenue between GRTgaz and Teréga. This difference is transferred between the TSOs.

CRE plans to maintain the principle of this compensation flow between the two operators.

3.2.2.2 Principles of the annual tariff change

Schedule of changes to tariff terms

Ever since the ATRT4 tariff, which came into force in 2009, gas transmission tariffs have been revised on 1 April each year. This schedule, which was fixed by CRE after a consultation, allows it to stay in line with the gas storage year, which extends from 1 April in year N to 31 March in year N+1.

However, under the CAM Network Code, which came into force in 2013 was and revised in 2017[3], annual transmission capacities at interconnection points are allocated for a period extending from 1 October in year N to 30 September in year N+1. Auctions for the marketing of annual capacities begin on the first Monday of July of year N.

In line with the previous tariffs, CRE considers to maintain the current tariff schedule, from April to April, in order to maintain consistency between the transmission schedules, LNG terminals and storage facilities, while having the interconnection points tariffs evolve between October and October, in order to meet the constraint imposed by the Tariff network code to set, before the annual capacity auctions on interconnections, the level of tariff terms that will apply from October N to October N+1.

CRE plans to change the tariff terms according to the following schedule:

- Changes in tariff terms at IPs only on 1st October of each year, with an initial movement of these terms as from 1st October 2024;
- Changes in the grid's other tariff terms on 1st April of each year.

> Q10 : Are you in favour of maintaining the current April-to-April pricing schedule, with the exception of the tariff terms applicable to IPs, which would change on 1 October each year?

Annual change in the level of tariff terms

Net operating costs, net capital costs and capacity subscriptions can vary significantly from one year to the next. To avoid excessively unpredictable changes in network usage tariffs, CRE is considering adopting, as in the network tariffs currently in force, a predefined change in the tariff grids, which may make it possible to smooth out these effects over time. As is the case for the ATRT7 tariff, CRE envisages a mechanical annual change in the ATRT8 tariff based on principles that are almost identical to those of the previous tariff period.

The principle is to apply a variation Z to the tariff terms each year, defined as follows:

$$Z = CPI + X + k$$

Where:

- Z is the variation of the tariff grid on 1st April (or 1st October for some points) of year N;
- CPI is the forecast inflation rate excluding tobacco for the year N (for the ATRT7, it is the one stated in the draft finance law - PLF);
- X is the annual rate of change on the tariff grid (it might be different for GRTgaz and Teréga);
- k is the change in the tariff structure, expressed as a percentage, resulting from the reconciliation of the regulatory account (capped between +2% and -2% for the ATRT7). In the current tariff, it is different for the main network tariff terms and the regional network tariff terms.

[3] Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems and repealing Regulation (EU) No 984/2013

This annual change implies the inclusion of a smoothing term (LIS) in the TSOs' allowed revenue.

However, in view of the significant CRCP balances achieved over the period for certain operators, CRE has studied several alternative options for updating tariffs, at the request of the TSOs.

Firstly, in order to improve the way in which the effect of inflation is taken into account, CRE studied the possibility of taking into account, at the time of the annual tariff update for year N, a correction for the difference in inflation for year N-1 between the PLF forecast and the actual level (or failing that, the best estimate available at the time of calculating the annual tariff update). As this difference will have a lasting impact on costs, CRE considers that it is possible at this stage to take it into account to prevent it from having a lasting impact on the CRCP balance. CRE notes, however, that this measure is only useful if actual inflation is far from the value forecast in the PLF. This measure makes the formula for tariff increases marginally more complex and more sensitive to inflation variations.

Secondly, at the request of GRDF in particular, CRE studied an increase in the capping of the k factor to +/- 3% (currently limited to +/- 2%). If this option had been applied to the ATRT7 period, it would have had no impact on the balance of Teréga's CRCP at the end of the ATRT7 period, and would have increased the reconciliation of GRTgaz's CRCP at the end of the ATRT7 period. However, the effects of this measure are difficult to anticipate, particularly as the balances of the CRCP are, by their nature, linked to unforeseeable differences in charges or revenues compared with the trajectory adopted in the tariff deliberation, which a priori have no reason to remain of the same sign. CRE therefore considers that increasing this factor would contribute to increasing tariff variability during the period without guaranteeing a lower CRCP balance at the end of the tariff period.

Lastly, Teréga made two proposals in its tariff file for ATRT8 aimed at accelerating the reconciliation of its CRCP.

The first is the netting of CRCP between TSOs before reconciliation, which works as follows:

- when the CRCP balances of the two operators are of opposite signs, they are reconciled as far as possible between them before being transferred to allowed revenues (and covered by tariffs);
- the amount of this reconciliation is transferred from one TSO to the other.

The second is the mutualisation of the threshold for clearing the CRCP of the two TSOs, the proposed operation of which is as follows: the $k_{national}$ would no longer be the weighted average of the k-factors of the two TSOs established separately, but would be calculated by directly comparing the cumulative balances of the CRCP and the allowed revenues of the two TSOs.

Teréga's proposals for netting the TSOs' CRCP and pooling allowed revenue with GRTgaz for the CRCP clearance calculation can only be envisaged for changes in the national gas transmission tariff, in line with the logic of joint changes in main network tariffs applied since the creation of a single gas market zone (Trading Region France, TRF) in 2018. These mechanisms would therefore mean being able to distinguish between a regional and national CRCP per operator (currently calculated indiscriminately), and limit them to the CRCP and allowed revenues linked to the national network. At this stage, CRE considers that they would complicate the annual changes for a marginal gain.

CRE points out that, in the ATRT7 tariff, it has opted for a single annual tariff change for the whole of GRTgaz's and Teréga's main transmission system. At this stage, CRE is considering renewing this approach, which improves visibility of changes in the tariff terms for the main transmission system.

The principles envisaged as a result are as follows:

- for main network tariff terms in force on 31 March of year N, the following percentage change:

  $Z_{national} = IPC + X_{national} + k_{national}$
  where

  - $Z_{national}$ is the variation in the tariff grid at 1 April of year N, expressed as a percentage and rounded to the nearest 0.01%;
  - CPI: the forecast inflation rate excluding tobacco for year N taken into account in the draft finance law for year N [to which may be added the difference between actual inflation for year N-1 as calculated by INSEE (or failing that, the best available forecast) and the forecast inflation rate for year N-1 taken into account in the draft finance law for year N-1].
  - $X_{national}$ is the annual evolution factor in the main network tariff grid;
  - $k_{national}$ is the percentage change in the tariff grid, capped at +/-2% in ATRT7 [possibly +/-3%], corresponding to the average of the k_{GRTgaz} and $k_{Teréga}$ coefficients, weighted by revenue from capacity subscriptions.

  By exception, changes in the terms relating to IPs apply from 1 October each year.

- for the tariff terms for GRTgaz's regional network in force on March 31st of year N; the following percentage change:

$Z_{GRTgaz} = IPC + X_{GRTgaz} + k_{GRTgaz}$
where

- Z_{GRTgaz} is the variation in the tariff grid on April 1 of year N, expressed as a percentage and rounded to the nearest 0.01%;
- CPI: the forecast inflation rate excluding tobacco for year N taken into account in the draft finance law for year N [to which may be added the difference between actual inflation for year N-1 as calculated by INSEE (or failing that, the best available forecast) and the forecast inflation rate for year N-1 taken into account in the draft finance law for year N-1].
- X_{GRTgaz} is the annual evolution factor on GRTgaz's regional network tariff grid, set by CRE in its tariff deliberations;
- k_{GRTgaz} is the percentage change in the tariff grid, capped at +/-2% [possibly +/- 3%], resulting mainly from the clearing of the balance of GRTgaz's regulatory account (CRCP).

- for the tariff terms for Teréga's regional network in force on 31 March of year N, the following percentage change:

$Z_{Teréga}= IPC + X_{Teréga}+ k_{Teréga}$
where

- $Z_{Teréga}$ is the variation in the price scale at 1 April of year N, expressed as a percentage and rounded to the nearest 0.01%;
- CPI: the forecast pre-tobacco inflation rate for year N taken into account in the draft finance law for year N [to which may be added the difference between actual inflation for year N-1 as calculated by INSEE (or failing that, the best available forecast) and the forecast inflation rate for year N-1 taken into account in the draft finance law for year N-1].
- $X_{Teréga}$ is the annual evolution factor on Teréga's regional network tariff grid, set by CRE in its tariff deliberation;
- $k_{Teréga}$ is the percentage change in the tariff grid, capped at +/-2% [possibly +/- 3%], arising mainly from the clearing of the balance of Teréga's regulatory account (CRCP).

The ATRT7 tariff provides for an inter-operator transfer from Teréga to GRTgaz, depending on the level of subscriptions at the Pirineos exit point. This was introduced after the merger of the TRF zones. In view of the fall in subscriptions at this exit point, CRE is considering replacing it with an inter-operator flow resulting from the equalisation of main network tariff terms and making it possible to ensure that the costs and revenues associated with the two operators' main network are matched.

In addition, CRE could implement structural changes and changes to regulatory incentives for marketing and quality of service at the time of the annual changes to the ATRT8 tariff.

Q11 : Are you in favour of the schedule and principles for tariff changes envisaged by CRE for the ATRT8 tariff?

Q12 : Do you have any comments on the changes in the calculation of tariff increases, in particular with regard to the considered adjustment of the CPI term to take account of the difference in inflation between the assumption used and the inflation achieved in N-1? Are you in favour of maintaining the k-factor at +/-2%?

Q13 : Are you in favour of the principle of netting TSO CRCP proposed by Teréga? Are you in favour of the principle of pooling the threshold for clearing TSO CRCP proposed by Teréga?

3.3 Incentive-based regulation on cost control

3.3.1 Incentive-based regulation of operating expenses

Network tariffs are calculated on the basis of assumptions about costs and revenues, which make it possible to define trajectories for the various items. As indicated in section 3.2.2.3 of this consultation document, an a posteriori adjustment mechanism, the regulatory account (CRCP), is used to take into account the differences between the expenses and income actually recorded and the expenses and income forecast for certain previously identified items.

CRE considers that the inclusion of an item in the CRCP should be assessed in the light of the following two criteria:

- predictability: a predictable item is one for which it is possible, for the operator and for CRE, to forecast with reasonable confidence the level of costs incurred and revenue received by the operator over a tariff period;

- control: a controllable item is one for which the operator is able to control the level of expenditure/revenue over the course of a year, or has the power to negotiate or influence its level, if this level is set by a third party.

These principles have been in force for several tariff periods. Furthermore, tariff treatment cannot be reduced to a single alternative in terms of item coverage, between 100% and 0% at the CRCP. Thus, for certain items that are difficult to control and/or predict, CRE considers that it is appropriate to provide operators with partial incentives (see section 3.3.1.2).

3.3.1.1 No coverage on the CRCP for most operating expenses

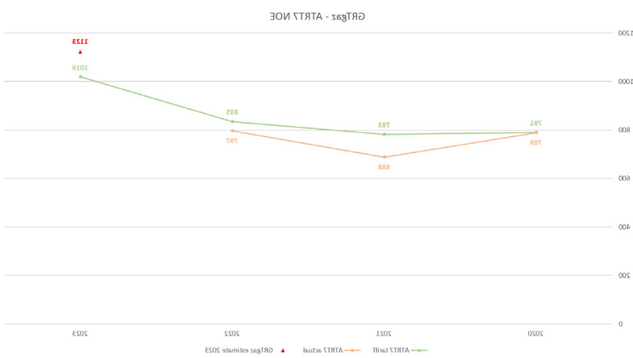
The tariff regulation framework in force differentiates three categories of net operating expenses (NOE), which are subject to specific tariff treatment:

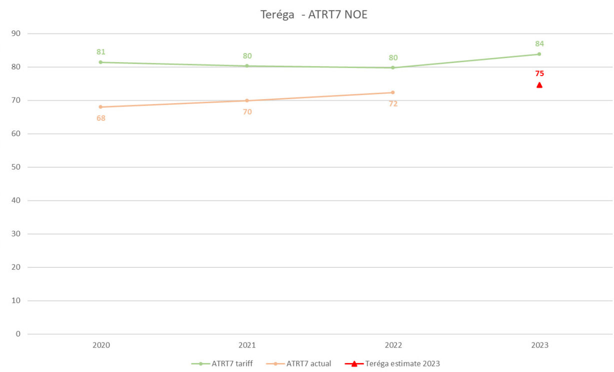
- incentivised net operating costs: operators are incentivised to control their operating costs, and retain all productivity gains or losses that could be made in relation to the trajectories defined by CRE. Most of the operators' operating costs fall into this category (purchases excluding energy, personnel costs, external services, etc.);
- partially incentivised net operating expenses: some expense items that depend on factors that are partly controllable by the operators (in particular energy expenses) are recorded in part in the income and expense adjustment account (CRCP). The rate of sharing of gains or losses in relation to the forecast trajectory set by CRE is generally between 10% and 20% (the operator retains between 10% and 20% of the difference and the remainder is borne by the tariff);
- non-incentivised net operating costs: for cost and revenue items that are difficult for operators to predict and control, the variances between actual and forecast are fully taken into account in the CRCP.

The incentive levels for non-incentivised or partially incentivised expense items envisaged by CRE are detailed in section 3.3.1.2. of this public consultation.

Incentive regulation of net operating costs is intended to encourage operators to improve their deviations from the set trajectory, while allowing them to keep the gain made in relation to the trajectory.

CRE notes that the costs incurred by operators have been lower overall than the trajectory set in the tariffs[4]:





Some of the discrepancies are due to productivity gains by the operator, while others are the result of an overestimation of forecast costs, due in particular to the asymmetry of information between the operators and the regulator. This observation justifies the use of in-depth audits to analyse operators' requests during the tariff work.

It is not in itself problematic for operators to beat their trajectory insofar as the objective of the incentive is precisely to obtain gains over time in the interests of end consumers. However, it is essential, and it is CRE's responsibility, to ensure that the efforts made by operators in previous tariff periods are properly taken into account when setting tariff levels from one tariff period to the next. In this respect, the level of efficiency revealed by incentive regulation during a tariff period must be taken into account when setting tariffs for the following period.

Consequently, CRE plans to maintain the CRCP coverage mechanisms, differentiated according to the type of expense (incentivised/partially incentivised/non-incentivised for the majority of operating expenses), and considers in its work on the level of operating expenses for the next tariff period, that the last level achieved (adjusted for inflation) is the standard to be used (2022): any request that deviates significantly from this must be duly justified by the operator. Furthermore, in the current period of sustained decline in consumption and subscriptions to gas

[4] In these graphs, the ATRT7 trajectories include the annual update of energy, CO2 and consumable costs, as well as the inflation update for other costs. For Teréga, this also includes the mid-period update of the R&D trajectory and the change in classification of certain Teréga expenses from OPEX to CAPEX from 2022.

transmission capacity, any new charges requested by operators should be offset as a matter of priority by savings on other expenditure items.

Q14 : Are you in favour of maintaining the current regulatory framework for the majority of operating costs?

3.3.1.2 Coverage by CRCP of certain items

Reminder of the current framework

As indicated in section 3.2.2.3 of this public consultation, an a posteriori adjustment mechanism, the regulatory account CRCP), makes it possible to take into account the differences between the income and expenditure actually recorded and the forecast income and expenditure for certain previously identified items. These are items that are difficult for operators to predict and control.

The items concerned in the ATRT7 tariff period are listed below.

Items fully covered by the CRCP:

The difference between the forecast inflation taken into account by CRE for net operating expenses and the inflation actually recorded is fully covered by the CRCP.

The expenses fully covered by the CRCP are as follows:

- capital costs, taken into account at 100%, with the exception of those covered by the incentive regulation mechanism for "non-infrastructure" capital costs;
- costs for GRTgaz linked to the agreement between GRTgaz and Teréga for GRTgaz's use of Teréga's network. As the income for Teréga is also covered in full by the CRCP, the impact of a change in the amount of the contract is zero for the overall cost of gas transmission in France;
- the costs associated, where applicable, with the remuneration by TSOs of consumers connected to the transmission network who have signed an interruptibility contract on the basis of article L.431-6-2 of the Energy Code;
- R&D operating expenses, with special treatment (see part 3.6): at the end of the tariff period, if the TSO has spent less than the forecast trajectory, the difference is returned 100% to users via the CRCP. If the TSO has spent more than the forecast trajectory, the difference remains the responsibility of the TSO;
- costs arising from congestion management mechanisms within the single market area;
- all the costs incurred by GRTgaz in converting H-gas into L-gas;
- charges for Teréga relating to the repayment to GRTgaz of part of the revenue received at the Pirineos network interconnection point (IPs), following the creation of the single market area on 1 November 2018;
- costs associated with contracts with other regulated operators, in particular storage operators.

The following revenues are fully covered by the CRCP:

- income from services for third parties, the performance of which is uncertain and over which the TSOs have no influence (e.g. linked to land development work);
- income for Teréga linked to the agreement between GRTgaz and Teréga for the use by GRTgaz of Teréga's network. As the costs for GRTgaz are also fully covered by the CRCP, the impact of a change in the amount of the contract is zero for the overall cost of gas transmission in France;
- income generated by congestion relief mechanisms within the single market area;
- revenue for GRTgaz from the repayment by Teréga of part of the revenue received at the Pirineos network interconnection point (IPs), following the creation of the single market area on 1 November 2018;
- income from the connection of biomethane production units and CNG stations;
- revenue associated with contracts with other regulated operators, in particular storage operators;
- the repayment made by the DSOs to the TSOs in respect of the share of the biomethane injection charge collected from producers connected to the distribution network, intended to cover the OPEX associated with the TSOs' backhauls (see part 5.3 of this consultation);
- the income from connecting combined-cycle gas turbine (CCCG) and combustion turbine (TAC) plants.

The inter-operator transfer between the two TSOs associated with the distribution of the change in the national tariff factor k (see part 3.2.2.4 of this deliberation) is also 100% covered by the CRCP.

Items partially covered by the CRCP:

Two expense items are partially covered by the CRCP:

- Energy costs (gas and electricity) and purchases and sales of CO_2 quotas. Since 1 April 2023, these costs have been covered:
    - 90% by the CRCP for the portion of the difference between actual figures and the forecast reference trajectory for energy costs that is less than or equal to, in absolute terms, 50% of the forecast trajectory;
    - 100% by the CRCP for the portion of the difference between actual performance and the projected baseline energy costs, in absolute terms, in excess of 50% of the projected baseline.
- consumables costs (THT), 80% of which are included in the CRCP. The reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is 100% covered by the CRCP.

Operators' demand

Charges relating to the implementation of the future European regulation to reduce methane emissions from the energy sector

The European Commission has proposed the adoption of a regulation to reduce methane emissions from the energy sector in December 2021 (the regulation has not yet been adopted). At this stage, the draft regulation provides for the introduction of obligations on gas operators to detect and repair methane leaks.

In view of the uncertainties surrounding the obligations that may be introduced for operators, and the resulting expenditure, GRTgaz is asking for these costs to be covered 100% by the CRCP for the coming tariff period.

GRTgaz and Teréga also request that the forecast trajectory of expenses linked to the future implementation of this regulation be updated during the tariff period, once the regulation has been adopted.

CRE's preliminary analysis

CRE notes that the impact of the new regulation on methane emissions on operators' costs is still very uncertain. It will depend in particular on the provisions set in the regulation when it is adopted, as well as on the application timeline for the new measures. The relevance of a cost trajectory that would be set in line with the current version of the draft regulation would therefore be limited.

Consequently, **CRE plans to set the load trajectory and the regulatory framework for the gas operators concerned once the regulation has been adopted.**

> Q15 : Are you in favour of CRE's position concerning the postponed timetable for setting the regulatory framework and the trajectory of charges relating to the implementation of the future European regulation aimed at reducing methane emissions from the energy sector?

Energy benefit-in-kind charges ("*Avantage Nature Energie*")

Employees of the Electricity and Gas Industries (IEG), of which GRTgaz is a part, benefit from a preferential rate for gas and electricity (known as the "agent rate"). In return, each IEG company pays EDF and Engie a sum each year to cover the difference between the agent tariff and the cost price of these two companies.

Under the current framework, these costs are fully incentivised, as are most of operating costs. GRTgaz is asking for them to be fully covered by the CRCP for the new tariff period, in view of the uncertainties surrounding electricity and gas prices.

CRE's preliminary analysis

CRE notes that the amount of GRTgaz's outpayments to EDF and Engie is set under a negotiated contract between the various companies concerned: it therefore considers that maintaining a regulatory framework that encourages the setting of a relevant level for this compensation is justified.

CRE also considers that maintaining an incentive based on the volumes of energy consumed is justified, in line with the sobriety objectives set by the government.

> Q16 : Do you agree with CRE's preliminary analysis of the incentive-based regulation of GRTgaz's ANE (Energy Benefit in kind) charges?

Unpaid bills from biomethane producers

Teréga is requesting that the CRCP cover 100% of the costs of connecting biomethane production facilities resulting from unpaid bills by customers.

CRE's preliminary analysis

CRE considers that Teréga must make its best efforts to recover its amounts due. At this stage, CRE plans to examine the coverage of unpaid amounts on a case-by-case basis.

Changes in the rate and methods of recovering costs related to congestion management and the interruptibility mechanism, as well as the redistribution of surplus revenue from capacity auctions

Charges related to congestion management and interruptibility mechanisms, as well as surplus revenue from capacity auctions, are included in the TSOs' allowed revenue, and deviations from the trajectory are covered 100% by the CRCP.

In 2022 and 2023, these costs and surpluses have risen sharply as a result of changes in gas demand and supply patterns linked to the fall in supplies of Russian gas to Europe. A guaranteed interruptibility mechanism has also been introduced to encourage customers to limit their consumption in the event of tension over security of supply.

The fact that these are fully covered by the CRCP means that the risks of changes in congestion absorption and interruptibility charges relative to the trajectory are fully covered for TSOs. However, GRTgaz considers that the rate of redistribution and recovery of the CRCP is not fast enough for these costs, which can vary significantly and uncertainly. GRTgaz proposes that the costs associated with congestion absorption mechanisms and guaranteed interruptibility should be billed directly to shippers every month, using a mechanism similar to that used for balancing.

The procedures for redistributing surplus revenue from capacity auctions were changed when the ATRT7 tariff was updated on 1 April 2022: until then, the amounts were calculated by each TSO and redistributed to each shipper in proportion to the quantities of gas delivered to end consumers on the transmission system. Since 1 April 2022, surpluses have been paid directly to system users via the CRCP. GRTgaz would like to return to the redistribution arrangements in force at the start of the ATRT7, in order to speed up the rate of redistribution of these revenues, in a symmetrical manner in relation to congestion absorption and interruptibility charges.

CRE's preliminary analysis

Monthly recovery of congestion charges would create an additional short-term incentive for shippers to participate in the smooth operation of the system in the event of congestion. As such, it could help to improve the operation of the TRF if the situation observed during the winter of 2022/2023 were to recur.

However, CRE believes that the recovery of congestion and interruptibility charges and the redistribution of surplus auction revenue should be made to all network users, not just those supplying French consumers. CRCP coverage is the most efficient way of achieving this objective. It also ensures that all these costs and revenues are passed on to, or recovered from, end consumers.

At this stage, CRE is therefore not in favour of changing the rate and method of recovery of the costs associated with the congestion absorption mechanisms and the interruptibility mechanism, and of the surplus revenue from capacity auctions.

> Q17 : Are you in favour of the change proposed by GRTgaz to the rate and method of recovery of the costs associated with the congestion absorption mechanisms, the interruptibility mechanism and the surplus revenue from capacity auctions?

GRTgaz and Teréga are also calling for changes to the framework for regulating energy charges. This point is dealt with in the following section (section 3.3.1.3).

Other income and expenditure items

CRE plans to maintain the level of incentives for other costs and income for the coming tariff period, as their level of predictability and control by operators has not changed during the current tariff period.

> Q18 : Do you agree with CRE's position that the level of incentives for other operating income and expenses should be maintained?

3.3.1.3 Incentive regulation of energy charges

TSO energy costs are made up of energy costs for compressors (gas and electricity) and purchases and sales of CO_2 quotas by TSOs. The scope of the incentivised expenses excludes those linked to backhauls.

In order to encourage TSOs to control these costs, the incentive system in force during the ATRT7 period provides for 80% coverage by the CRCP of variances in this item. This partial coverage is intended to encourage operators to control their costs.

However, following the significant increase in wholesale prices in 2022, the gaps in the energy item and its incentive could potentially reach very large amounts. This is why, in its decision of 31 January 2023[5] on the update of the gas transmission tariff, CRE exceptionally increased the coverage of energy costs:

- to 90% by the CRCP for the fraction of the difference between actual figures and the forecast reference trajectory for energy costs that is less than or equal to, in absolute terms, 50% of the forecast trajectory;
- 100% by the CRCP for the portion of the difference between actual performance and the projected baseline energy costs, in absolute terms, in excess of 50% of the projected baseline.

Operators' demand

- For ATRT8, GRTgaz and Teréga are asking for the annual update of energy cost assumptions to be taken directly into account in their allowed revenue for year N and not via the CRCP.
- GRTgaz is asking for the bonus or malus on energy charges to be limited to +/- €3 million/year.
- Teréga requests 100% coverage by the CRCP for the portion of the difference between actual figures and the forecast reference trajectory for energy costs, in absolute terms, in excess of 20% of the forecast trajectory.

CRE's preliminary analysis

CRE considers that taking the annual update of energy charges directly into account in the allowed revenue for year N is not justified in view of the results of the ATRT7, which enabled Teréga to clear its CRCP in its entirety, and GRTgaz to accumulate a CRCP balance to be returned to consumers, mainly linked to surplus revenues linked to capacity auction that were higher than anticipated in the ATRT7. These annual updating procedures would significantly increase the annual variability of the tariff and would require annual renegotiations between CRE and the TSOs on this item.

CRE also considers that Teréga's proposal to lower the incentive constraint would considerably weaken the impact of incentive regulation on controlling energy expenditure.

For the next tariff period, CRE wishes to maintain a sufficient incentive for TSOs to control their energy costs. However, this incentive must not become disproportionate as a result of a rise in energy prices that is too different from the assumptions made. At this stage, CRE is therefore considering applying differentiated incentives for the volume of energy consumed and for the purchase price of this energy:

- Maintain 80% coverage of the difference between the forecast volume and the volumes consumed, in line with the level of incentives applicable to other regulated infrastructure operators in France. CRE considers that it is important to continue to encourage operators to optimise their energy consumption and consume less. The volumes forecast and consumed will be valued at the reference price defined below.
- Encourage operators on the basis of a reference purchase price for gas and electricity. This reference price would be determined each year, based on the wholesale prices recorded for a basket of reference products to be defined. This reference price would be applied to all gas and electricity volumes.

However, defining the reference price for TSOs' energy purchases is more complex than in the case of losses for other regulated infrastructure operators. This is because TSOs' gas and electricity consumption is highly volatile over the year and difficult to forecast accurately from one year to the next. Over the coming months, in-depth work will be carried out with the TSOs to verify the feasibility of such a system.

Q19 : Do you share CRE's view that the energy expenses incentive scheme should be reviewed?

[5] CRE decision of 31 January 2023 on the annual change in the tariff for use of the GRTgaz and Teréga natural gas transmission networks from 1 April 2023

3.3.2 Incentive regulation mechanism for investments

3.3.2.1 Incentive for controlling costs for investments with a budget of over €20 million

The ATRT7 tariff provides an incentive to control costs for projects with a budget of over €20 million: these projects are audited in order to set a target budget, and a bonus or malus is awarded to the operator depending on the difference between the target budget and actual expenditure, with a neutrality band of +/- 5% around the target budget.

During the ATRT7 tariff period, CRE audited 6 projects with budgets of over €20m. The audits led, on average, to adjustments of the budgets presented of -9% for the TSOs. These audits also made it possible to analyse the operators' cost-setting methods.

At this stage, CRE is considering maintaining the existing system for the ATRT8 tariff.

> Q20 : Do you agree with CRE's position that the cost control incentive mechanism should be renewed for network investments with a budget of more than €20 million?

3.3.2.2 Incentives for controlling costs of projects outside major projects

The ATRT7 tariff introduced an incentive mechanism based on CRE's selection, without any predefined criteria, of a few projects or categories of projects with budgets below the €20 million threshold, in order to audit them and apply incentive regulation identical to that applicable to investment projects with budgets of €20 million or more.

One project with a target budget of less than €20m was audited by CRE during the ATRT7 tariff period. CRE proposes to renew this possibility of setting up targeted budgets.

> Q21 : Do you agree with CRE's position that the cost control incentive mechanism should be renewed for network investments other than major projects?

3.3.2.3 Incentives for controlling costs for "non-infrastructure" investments

<u>Reminder of the mechanism and its objectives</u>

Gas transmission infrastructure operators are encouraged to control their capital costs in the same way as their operating costs on a scope of so-called "non-infrastructure" costs including assets such as property, vehicles and information systems (IT). This regulatory framework was introduced in the ATRT6 tariff.

This mechanism encourages operators to optimise their overall charges for these three cost items. It consists of defining, for the tariff period, the trajectory of capital costs, which are excluded from the scope of the CRCP[6]. The operator therefore retains 100% of any gains or losses during the tariff period. At the end of the tariff period, the actual value of the fixed assets is taken into account in the RAB, so that gains or additional costs can be shared with infrastructure users in subsequent tariff periods.

The aim is that, for these three items where trade-offs between capital and operating expenses are possible, the incentive for operators should be the same.

In addition, CRE has introduced a specific experimental mechanism in the ATRT7 tariff for charges relating to Teréga's IT. This mechanism provides the operator with an incentive based on a common trajectory including operating expenses and commissioning, and provides that the assets enter the RAB on the basis of an amount fixed ex ante in the trajectory, and not on the basis of expenses actually incurred at the end of the tariff period. CRE has set a sharing rate of 50% of the operator's gains or losses, by including 50% of the deviations from the overall trajectory in Teréga's CRCP.

<u>Assessment of the mechanism over the ATRT7 period</u>

Overall, since the introduction of the mechanism to encourage cost control for "non-infrastructure" investments, the trajectories achieved by the operators show that there has been no drift in costs: overall expenditure envelopes are under control. This was the main objective of the system.

With regard to the common framework (i.e. excluding the specific mechanism applied to Teréga's IT expenses), CRE now has extensive feedback enabling it to assess the effectiveness of the system more accurately. Thus, while operators are encouraged to keep overall costs under control, feedback shows that the regulatory framework provides them with flexibility, allowing them to arbitrate during the tariff period between an acquisition strategy (or

[6] Framework applied only to the scope of items relating to vehicles and property for Teréga.

internal IT development) and a leasing strategy (or IT outsourcing). In addition, during the tariff period, it ensures that users of the infrastructure are not adversely affected if the operator finally adopts an acquisition strategy (through the tariff - capital charges being covered by the CRCP under nominal conditions). With regard to the specific framework for Teréga's assets, experience feedback for the period 2020-2023 alone shows overall control of its costs.

However, CRE has identified a drawback to these mechanisms in the case of major projects that were planned but not carried out during the tariff period. Operators could be covered twice for the costs of a project that is postponed from one tariff period to the next, if the costs relating to this project are again included in the next tariff period.

GRTgaz's review

In current € millions	2020	2021	2022	2023 (forec.)	Total	Spread (actual- forecast)
Not including infrastructure						
Forecast NCE (adjusted for actual inflation)	88.6	100.5	115.8	114.5	419.4	
Forecast NOE (adjusted for actual inflation)	100.8	99.1	103.8	110.2	413.9	
TOTAL forecast	**189.4**	**199.6**	**219.5**	**224.7**	**833.3**	
Actual NCE	91.3	97.1	108.8	116.2	413.4	-6.0 (-1 %)
Actual NOE	106.0	102.0	108.0	118.7	434.7	+20.8 (+5 %
TOTAL actual	**197.3**	**199.1**	**216.8**	**234.9**	**848.2**	**+14.9 (+2 %)**

Teréga's review

In current € millions	2020	2021	2022	2023 (forec.)	Total	Spread (actual- forecast)
Property and vehicles						
Forecast NCE (adjusted for actual inflation)	5.3	6.4	7.9	8.4	28.0	
Forecast NOE (adjusted for actual inflation)	3.9	3.9	4.1	4.3	16.1	
TOTAL forecast	**9.2**	**10.3**	**12.0**	**12.6**	**44.1**	
Actual NCE	4.8	4.9	5.1	5.3	20.1	-7.9 (-28 %)
Actual NOE	2.7	2.8	3.2	3.4	12.2	-3.9 (-24 %)
TOTAL actual	**7.5**	**7.7**	**8.3**	**8.7**	**32.3**	**-11.8 (-27 %)**

In current € millions	2020	2021	2022	2023 (forec.)	Total	Spread (actual- forecast)
Information system						
Forecast commissionning	13.6	10.6	8.2	8.3	40.7	
Forecast NOE (adjusted for actual inflation)	10.2	11.6	13.7	13.9	49.4	
TOTAL forecast	**23.8**	**22.1**	**21.9**	**22.2**	**90.1**	
Actual commissioning	12.2	12.6	8.7	9.7	43.2	+2.5 (+6 %)
Actual NOE	9.7	11.4	13.7	13.9	48.7	- 0.8 (-2 %)
TOTAL actual	**21.9**	**24.0**	**22.4**	**23.6**	**91.9**	**+1.8 (+2 %)**

Changes envisaged for the ATRT8 period

Feedback from recent tariff periods shows that this regulatory mechanism is effective in inciting "non-infrastructure" investments. However, the case of major projects that were not completed as planned during the tariff period must be addressed.

Operators' demand

On the whole, operators are in favour of renewing the mechanism.

On the basis of initial feedback on its specific regulatory framework for IT costs, Teréga is asking for the maintaining of its specific incitation mechanism and for its scope to be adjusted to include costs relating to personnel costs and expenditure on asset management in the IT field, and to exclude certain costs relating to R&D and industrial IT.

CRE's preliminary analysis

At this stage, CRE is considering renewing the cost-containment incentive scheme for "non-infrastructure" investments, but restating in the trajectory set for ATRT8 the major projects that would have been included in the ATRT7 trajectory but not carried out by the operators, in order to avoid double coverage of the operators' costs.

With regard to Teréga's request, CRE considers that the review does not allow it to conclude that the mechanism is more effective than the common framework. In addition, maintaining two different mechanisms in parallel makes the system more complex. At this stage, CRE is considering incentivising Teréga's IT investments in the same way as those of other operators.

Finally, as with any incentive regulation, the level of operating and capital costs adopted for the ATRT8 tariff will be based on the level of performance achieved during the ATRT7 tariff.

> Q22 : Are you in favour of renewing the cost-containment incentive scheme for "non-infrastructure" investments?
>
> Q23 : Are you in favour of harmonising the regulatory framework for Teréga's IT assets with the framework applied to other operators?

3.4 Incentive regulation for commercialisation

Under the ATRT7 tariff, 80% of the transmission revenue collected on the upstream main network (excluding main network exits, storage entries and exits) is covered, to encourage TSOs to maximise subscriptions. These upstream revenues also include:

- revenue from access and transactions at the PEG (gas exchange point);
- revenue from Alizés balancing services for GRTgaz and SET balancing services for Teréga;
- revenue from the UIOLI (Use it or loose it) and UBI (Use it and buy it) mechanisms;
- revenue from the auctioning of daily capacity.

Other transmission revenues are 100% covered by the CRCP.

Operators' demand

GRTgaz and Teréga consider that the end of long-term contracts and recent changes in demand and supply patterns make it too difficult to forecast subscriptions to IPs and PITTMs, even a year in advance, and that incentive regulation exposes them to too great a risk. Consequently :

- GRTgaz calls for the introduction of a ceiling of +/- €5 million/year for the bonus or malus linked to subscription sales;
- Teréga requests the removal of the incentive regulation for Pirinéos.

For ATRT8, Teréga has requested an annual review of the subscription assumptions in its allowed revenue for year N+1. As a reminder, the differences between the subscription income for an actual year and the assumption restated in the tariff deliberation are currently transferred to the CRCP.

CRE's preliminary analysis

During the current tariff period, operators have generally beaten their forecast subscription trajectories and have developed new capacity in the context of reconfiguration since the outbreak of war by Russia:

- creation of exit capacity to Germany at Obergailbach;
- increasing entry capacity from the Dunkirk and Fos LNG terminals;
- creation of entry capacity at Pirineos.

Incentive regulation of subscriptions has been effective from this point of view, as it has encouraged operators to maximise their revenues and develop additional capacity. TSOs have seized every opportunity for optimisation to increase capacity at interconnection points.

This was particularly useful during the gas supply crisis by maximising gas flows on the French network. In addition, a revenue surplus of around €500m (2023 has not yet been finalised) has returned to the CRCP.

However, the situation is not the same for the ATRT8 tariff. On the one hand, the potential for developing new capacity is now very limited, as the French transmission network has been used to the maximum during the crisis. On the other hand, the fall in long-term subscriptions makes the forecasting exercise, which is necessary for any incentive regulation, particularly risky and difficult.

As a result, CRE is currently considering not renewing the incentive regulation on upstream subscriptions for the next tariff period.

Lastly, CRE considers that the annual revision of subscription assumptions or energy charges is not justified in view of the results of the ATRT7, which enabled Teréga to clear its CRCP in its entirety, and GRTgaz to accumulate a CRCP balance to be returned to consumers, mainly linked to income from surplus revenue from capacity auctions that was higher than anticipated in the ATRT7. Revising these assumptions would significantly increase the annual variability of the tariff and would require annual renegotiations between CRE and the operator on this item. However, it is true that the drop in long-term subscriptions during the ATRT8 tariff generates a sharp drop in visibility on capacity revenues.

Q24 : Do you agree with CRE's proposal not to renew the incentive regulation on upstream subscriptions for the next tariff period?

3.5 Incentive regulation mechanism for quality of service

The incentive regulation of the quality of service of TSOs which is for the purpose of improving the quality of service provided to transmission system users in the fields considered particularly important for the correct operation of the gas market.

3.5.1 Reminder of the current service quality incentive regulation mechanism

For the current tariff period (ATRT7), TSO service quality is monitored by means of 28 indicators, four of which are financially incentivised.

These indicators were set by CRE after extensive consultation with market players, with the aim of improving service quality and promoting the smooth operation of the market in view of the challenges of the period, in particular the provision of information needed by users to balance their portfolios.

The 28 existing indicators cover the following themes:

- the quality and availability of data made available to shippers by TSOs (20 indicators, 4 of which are financially incentivised);
- compliance with forecasts provided to shippers concerning TSOs' works programmes (3 indicators);
- monitoring the handling of complaints (2 indicators)
- TSOs' environmental impact (3 indicators).

The four indicators subject to a financial incentive relate to the quality of consumption measurements made available to shippers, enabling them to balance themselves as well as possible:

- quality of the quantities measured at the transmission/distribution interface points (PITD) and transmitted to the DSOs the following day to calculate provisional allocations;
- quality of the quantities remotely read at the consumer delivery points (PIC) connected to the transmission network and transmitted the next day;
- quality of intra-day quantities telemetered at consumer delivery points (PIC) connected to the transmission network and transmitted during the day;
- quality of overall end-of-day gas consumption forecasts made the day before and during the day.

The results of these indicators are published on the TSOs' websites each month. Since 2016, the TSOs have been preparing and publishing on their websites a qualitative analysis of their annual performance.

3.5.2 Review of the ATRT7 programme

3.5.2.1 Financially incentivised indicators

Between 2019 and 2022, the TSOs maintained a high overall level on the financially incentivised indicators, confirming the increase in results from the previous period. In terms of the quality of data transmitted to market players, operators have generally maintained a high level of service quality. In particular, TSOs improved the quality of quantities measured at PITDs and transmitted to DSOs the following day to calculate provisional allocations.

The quality of forecasts has nevertheless been affected by Covid-19 in 2020 and 2021 and the context of sober consumption in 2022.

This was particularly the case for the consumption forecasts provided the previous day by the TSOs, the quality of which was slightly lower in 2021 than in 2020 at Teréga. According to the operator, this drop was due to the difficulty of adapting the forecasting models to the lockdowns and to poor weather forecasts in August 2021. As a reminder, in 2020, this indicator had already fallen significantly due to COVID-19 and successive lockdowns.

3.5.2.2 Non-financially incentivised indicators

<u>Quality and availability of data made available to shippers by TSOs:</u>

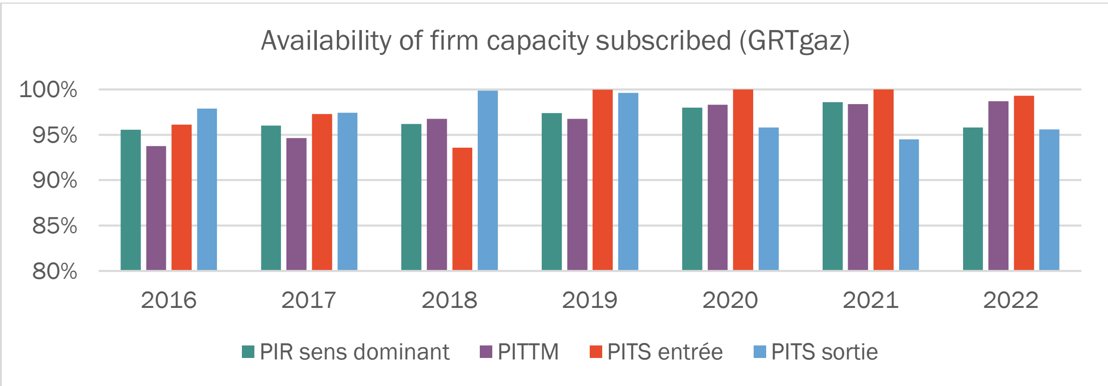
The non-incentive indicators on the quality and availability of data made available to shippers by TSOs have reached a very good level over the period from 2019 to 2022 (availability and compliance above 98%).

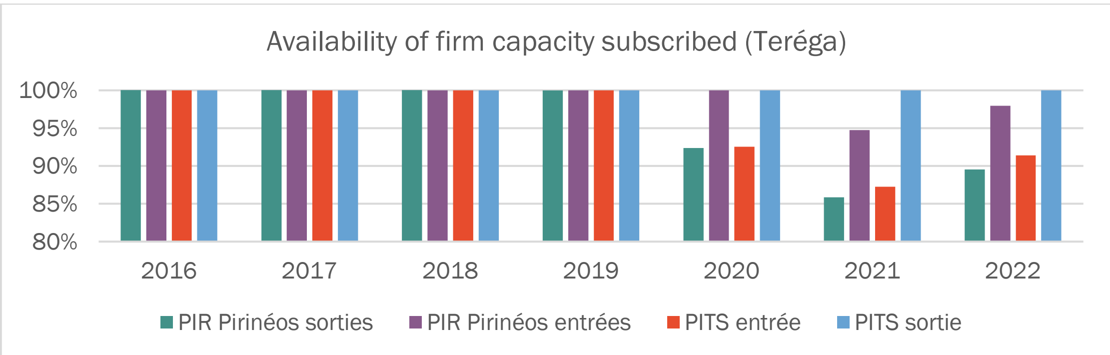
<u>Indicators on TSO work programmes:</u>

In ATRT7, the availability of firm capacity subscribed remained at a high level at GRTgaz, while there was a fall at Teréga on the Pirinéos IP and at the PITS entry point.

Teréga states that these decreases are due to the work carried out by the two TSOs, impacting the limits of the TRF and causing restrictions. GRTgaz states that this is a lasting trend that began in 2021, linked to the tightening of regulations on pipeline integrity and rehabilitation. In addition, the inversion of demand and supply patterns has led to the appearance of new southern → northern limits on the network, creating additional constraints when scheduling work.

The operators emphasise that a significant and coordinated effort has been made to optimise the scheduling of works and minimise the unavailability of capacity.





Restriction forecasts were generally reliable and prudent, which ensured satisfactory transparency for market players.

Indicators for handling claims:

The indicators on the number of complaints and the time taken to process them, introduced at the beginning of ATRT7, have improved at both TSOs:

GRTgaz	2020	2021	2022
Number of claims per year	26	24	23
Simple claims (average processing time in days)	11.8	1.5	0.8
Complex claims (average processing time in days)	6.4	7.5	3.7
Claims requiring investigation (average processing time in days)	NC	NC	NC

Teréga	2020	2021	2022
Number of claims per year	36	26	34
Simple claims (average processing time in days)	2.1	0.4	0.3
Complex claims (average processing time in days)	9.8	2.8	3
Claims requiring investigation (average processing time in days)	0.5	13	9.9

Overall, over the last few tariff periods, monitoring and incentivising quality of service indicators has improved TSO performance in the targeted areas. To remain effective, however, some indicators and the associated incentives need to evolve.

Q25 : Do you agree with the CRE's and the TSOs' assessment of quality of service over the last four years? Do you have any specific comments or suggestions on incentive regulation of quality of service?

3.5.3 Simplifying and adapting the system

3.5.3.1 Simplifying the current system

Incentive regulation of service quality has evolved to take account of the results obtained and feedback from experience. The incentives and targets set for operators have been gradually strengthened in order to improve their performance.

To simplify the current system, CRE is considering to remove the indicators relating to the provision of information on the operation of the TRF. These indicators, which have no financial incentive and measure the rate of availability of certain information, have always reached 100% since they were introduced. As the quality and availability of this information are very satisfactory, CRE considers to prioritise other information, detailed in the section below.

3.5.3.2 Biomethane injection indicators

The ATRT7 tariff did not include any quality of service indicators specific to biomethane producers: for this recent activity, the majority of whose sites are connected to the natural gas distribution network, CRE has introduced the following indicators (which are not financially incentivised) into the ATRD6 tariff of GRDF and the ELDs:

- response time for detailed studies for biomethane project developers;
- number of complaints following connection of biomethane installations.

Given the growing number of biomethane production sites connected to the gas networks, including the transmission networks, CRE considers that maintaining optimal conditions for these sites is a major challenge for GRTgaz and Teréga.

At a workshop held on 10 May 2023 on the ramp-up of renewable and low-carbon gas, CRE asked the players concerned about the relevant indicators to be taken into account to monitor operators' quality of service.

During the workshop, participants confirmed the importance of the issues identified by the CRE concerning the downward trend in gas consumption, which creates uncertainty about the outlet for renewable and low-carbon gas production. The participants also shared a desire to speed up the connection of facilities and develop flexibility solutions.

In view of the issues identified and the feedback from the above-mentioned workshop, CRE plans to introduce several quality-of-service indicators dedicated to renewable and low-carbon gas production sites.

First of all, it plans to introduce into the ATRT8 tariff the two indicators that already exist in the ATRD6 tariff (response time to detailed studies for project developers and number of complaints following connection of facilities), extending them to all renewable and low-carbon gases, and adapting them to the specific characteristics of transmission system operators. Transmission system operators carry out feasibility studies rather than detailed studies, and from which they make commitments to project developers regarding the conditions for connection and injection.

With regard to these two indicators, CRE does not envisage any financial incentives at this stage, as it would be complex to set an immediate target without any hindsight on the level of these indicators.

CRE is also considering the introduction of an indicator relating to the **time taken to install and commission a backhaul**. The number of renewable and low-carbon gas production sites is set to increase over the ATRT8 period, which will require a growing number of backhaul installations. It is important that these facilities are commissioned within a timeframe that is compatible with the commissioning of the production sites for which they will serve as an outlet.

CRE is also considering the creation of an indicator relating to **compliance with connection deadlines for renewable and low-carbon gas production sites**, in view of the expected increase in connections of these sites over the ATRT8 period.

Finally, CRE is considering the creation of an indicator relating to the **volumes of renewable and low-carbon gas capped**. CRE has noted uncertainties about the outlets for renewable and low-carbon gas production, due to a downward trend in gas consumption. CRE therefore plans to introduce a monitoring indicator (without any financial incentive) to track changes in the number of zones and producers affected by the capping of their production. Although this problem is more common on distribution networks, the aim would be to analyse the circumstances of local capping (seasonal or intra-monthly modulation, temporal and geographical evolution of the phenomenon, etc.), pending the implementation of network reinforcement investments validated by CRE.

Given the novelty of these indicators, and despite projections of an increase in the number of renewable and low-carbon gas production sites, CRE does not envisage providing financial incentives for these indicators if they were to be introduced in the ATRT8.

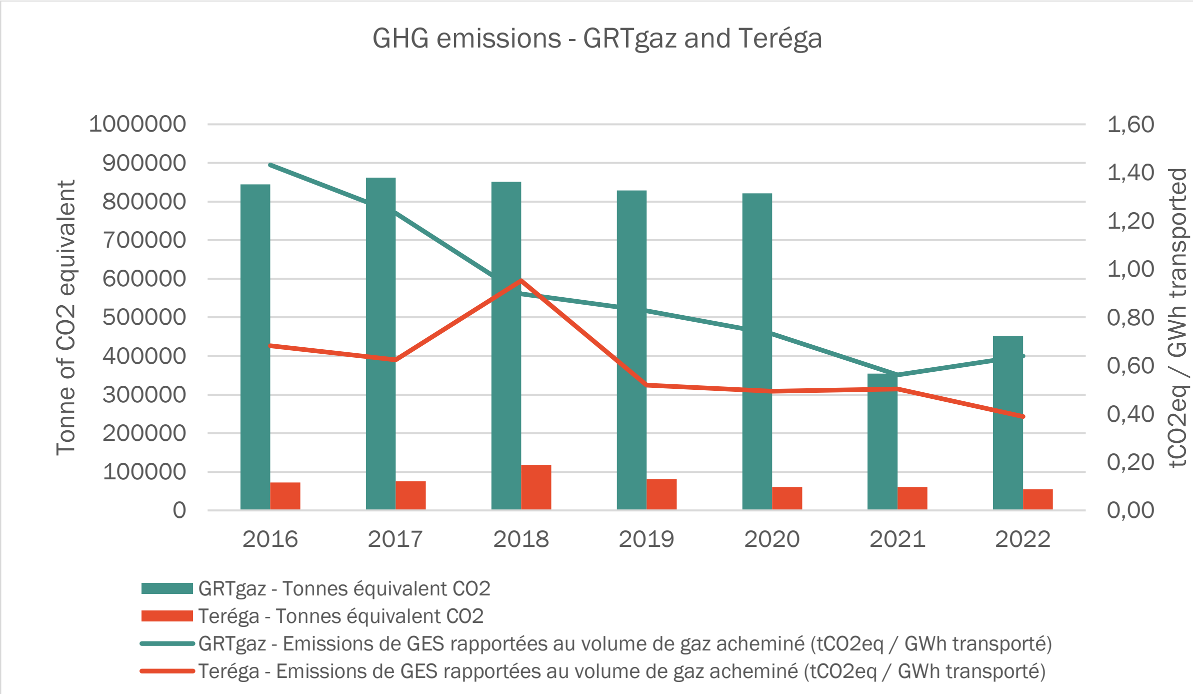
Q26 : Are you in favour of the changes to the incentive regulation system for quality of service envisaged by CRE for the ATRT8 tariff? Are you in favour of adapting the system to take account of issues relating to the injection of renewable and low-carbon gas?

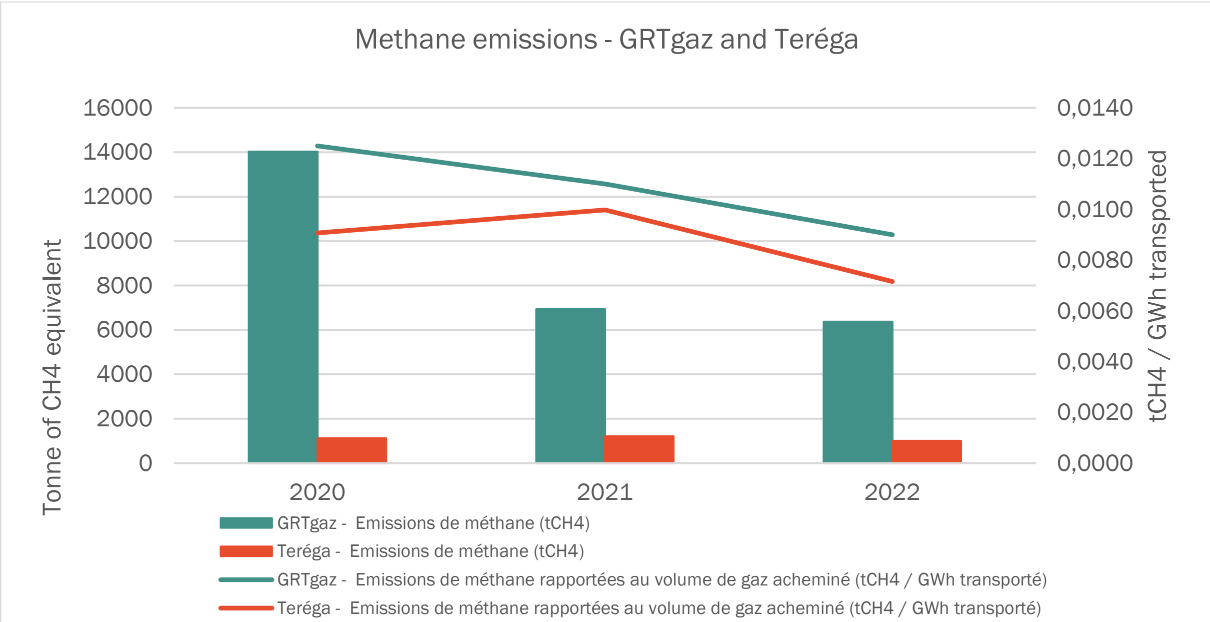
3.5.3.3 Environmental indicators

The ATRT7 tariff includes three environmental indicators that are not financially incentivised:

- annual greenhouse gas emissions (in CO_2 equivalent);
- monthly greenhouse gas emissions per volume of gas transported.
- methane emissions per volume of gas transported.

GRTgaz and Teréga's greenhouse gas and methane emissions are presented below:





These indicators for monitoring greenhouse gas emissions include both emissions proportional to the volumes of gas transported, which are only partially under TSO control and are based mainly on optimising gas flows, and methane emissions on the networks, which are more directly the result of network operation methods, such as recompressing and reinjecting gas during maintenance operations, rather than releasing it into the atmosphere.

GHG emissions relative to the volume of gas transported have followed a downward trend over the ATRT7 period, reflecting the efforts made by TSOs in this area.

Operators' demand

Teréga proposes to extend the financial incentive of the service quality monitoring system to the methane emissions indicator.

CRE's preliminary analysis

The European regulation aimed at reducing methane emissions in the EU's energy sector could shortly be adopted. In particular, this regulation will introduce a common framework for measuring and reporting methane emissions, the obligation to search for and repair methane leaks on pipelines, and a ban on certain practices (venting, flaring).

The future regulation will impose obligations on gas infrastructure operators. Financial incentives for greenhouse gas emissions, which are currently only monitored, could then be considered.

Q27 : Do you agree with CRE's analysis of the possibility of incentive regulation of greenhouse gas emissions?

3.6 R&D and innovation incentive regulation

In a context of rapid change in the energy landscape, network operators need to have the resources to carry out their research and development (R&D) and innovation projects, which are essential for providing an efficient, high-quality service to users, and to develop their network operating tools. In return, network operators must use these resources efficiently and transparently.

In order to meet these two requirements, incentive regulation of R&D and innovation (R&D&I) is currently based, for all operators, on:

- an asymmetrically incentivised R&D&I cost trajectory, which can be revised at mid-term: at the end of the tariff period, any amounts not spent during the period are returned to consumers, while any trajectory overruns are borne by the operators;
- the annual transmission to CRE of technical and financial information on all ongoing and completed projects, and the publication of a biennial public report.

During the ATRTR7 tariff period, GRTgaz's cost trajectory was €114 million and the amount spent during the period was €124 million, i.e. €10 million was borne by the operator. Teréga's cost trajectory was €10.3 million over the period, increased to €10.7 million under the mid-period window. The amount spent by Teréga over the period was €6.5m. The 4.2 M€ not spent are therefore returned to the consumer.

CRE plans to maintain the current incentive arrangements. At this stage, CRE considers that these arrangements do not encourage operators to choose between making savings on their R&D&I expenditure and preparing for the future. In addition, updating the mid-term review of the trajectory will give network operators greater flexibility in adapting their R&D&I programme.

Lastly, the smart grids counter for gas operators, introduced for the ATRT7 tariff period, has not been used. CRE proposes not to renew it for the ATRT8 tariff period.

Q28 : Do you have any comments on the incentive regulation framework for innovation and R&D envisaged by CRE for the ATRT8 tariff?

3.7 Adaptation of the tariff regulation framework to limit the risk of an excessive increase in the unit cost of transmission for future network users

This part of the public consultation deals with the tariff methods likely to meet the need to adapt infrastructures in a context of energy transition and structural decline in fossil gas consumption by 2050. These issues were the subject of the "Future of gas infrastructures" report[7] published by the CRE in April 2023, which concluded that most of the existing gas infrastructures would need to remain in operation in 2050.

As a result, the decline in gas consumption is likely to occur at a time when network and storage operators will continue to bear significant costs, and even new investment requirements linked to the energy transition, particularly for the integration of green gas. The relationship between the changes in allowed revenue requested by operators and their forecasts for use of their infrastructures during the next tariff period already illustrates this trend. This lack of correlation between changes in consumption and costs could lead to unsustainable price increases for consumers if the regulatory framework remains unchanged.

While CRE has been adapting operators' regulatory frameworks for several tariff periods and ensuring that operators keep their investments under control, additional levers for action could be implemented.

3.7.1 The outlook for decreasing consumption means that there is a risk of an increase in the unit cost of transmission

In its study on the future of gas infrastructures, CRE has selected three scenarios for gas consumption up to 2050, all of which involve a departure from the Ademe trend scenario (trend scenario with biomethane production reaching 86 TWh in 2050). These three scenarios are based on the assumption of a balance between annual consumption and production in 2050, i.e. the end of fossil gas consumption and the achievement of energy sovereignty:

[7] For more information: see the study "The future of gas infrastructures", CRE (2023)

- Ademe's S1 scenario (165 TWh of consumption in 2050), characterised by a very sharp decrease in the use of gas in the building sector, and the persistence of a residual base of consumption in collective housing with individual boilers;
- Ademe's S3 scenario (245 TWh of consumption in 2050), characterised by a less pronounced decline in gas use in buildings, strong growth in hybrid heat pumps and moderate growth in gas mobility;
- the network operators' scenario (SGR) (320 TWh of consumption in 2050), characterised by a less pronounced decrease in heating use, and strong growth in hybrid heat pumps and gas mobility.

The study shows that, despite the decrease in consumption, the sizing of France's gas infrastructures is unlikely to change significantly between now and 2050:

- both the gas transmission and distribution networks will continue to be needed for the most part. However, assets will be released, albeit to a limited extent;
- a significant proportion of storage capacity will still be required to meet the need for seasonal modulation of consumption.

Networks could also continue to expand to support the development of green gases and NGV mobility, and will have to adapt to the emergence of back-up use. As a result, gas operators' costs are not expected to decrease in the same proportions or at the same rate as gas consumption by 2050, leading to an increase in the unit cost of transmission ("scissor" effect).

3.7.2 Tariff levers exist to manage this risk

The first lever identified to limit the "scissor" effect is to adapt the distribution of capital charges over time, with the aim of increasing them in the shorter term in order to reduce them in the longer term, in line with anticipated trends in gas consumption. This will avoid passing on today's costs to tomorrow's consumers.

Three options, which may be combined but are not mutually exclusive, are presented in the following paragraphs:

1. putting an end to indexation of the RAB to inflation by switching to remuneration of the RAB at a nominal rather than real WACC;
2. adjusting the rate of depreciation (moving to degressive depreciation, higher initially and then lower), so that depreciation charges are more consistent with the decline in gas consumption;
3. reducing the depreciation period for certain assets, where this is relevant to their actual expected useful life.

In addition, these measures may not be enough to contain the price squeeze (scissor effect): the outlook for declining consumption therefore calls for network operators to step up the efficiency of their investment strategies, so that a shrinking consumption base only has to bear optimised investment costs.

3.7.3 The risk of an increase in the unit cost of transmission and the levers for managing this risk were the subject of a thematic consultation workshop

On 20 June 2023, a workshop was held on how to support the decline in gas consumption with an appropriate regulatory framework. The workshop was attended by 86 participants.

During the workshop, CRE's departments presented the challenges of the next generation of tariffs in relation to declining gas consumption. The gas infrastructure operators also presented their consumption trajectories for the next tariff period. The CRE departments then detailed the CRE's ideas regarding the allocation of capital costs over time and the optimised management of operators' assets.

Overall, CRE's proposals met with no opposition in principle, although some participants wondered about their consequences in terms of changes in tariff levels.

With regard to the challenges posed by a decrease in natural gas consumption, several participants agreed with CRE's assessment of the risk of an increase in the unit cost of transmission. Some stakeholders raised questions about coordination with decisions taken by local and regional authorities, customer support in the event of conversion to another energy source, and the social impact of an increase in the cost of energy.

With regard to the allocation of capital costs over time (de-indexation of the RAB, degressive depreciation), stakeholders mainly questioned CRE's departments on the impact of these measures on infrastructure tariffs, and on certain practical aspects of these changes to the framework (application to all assets, accounting management, etc.).

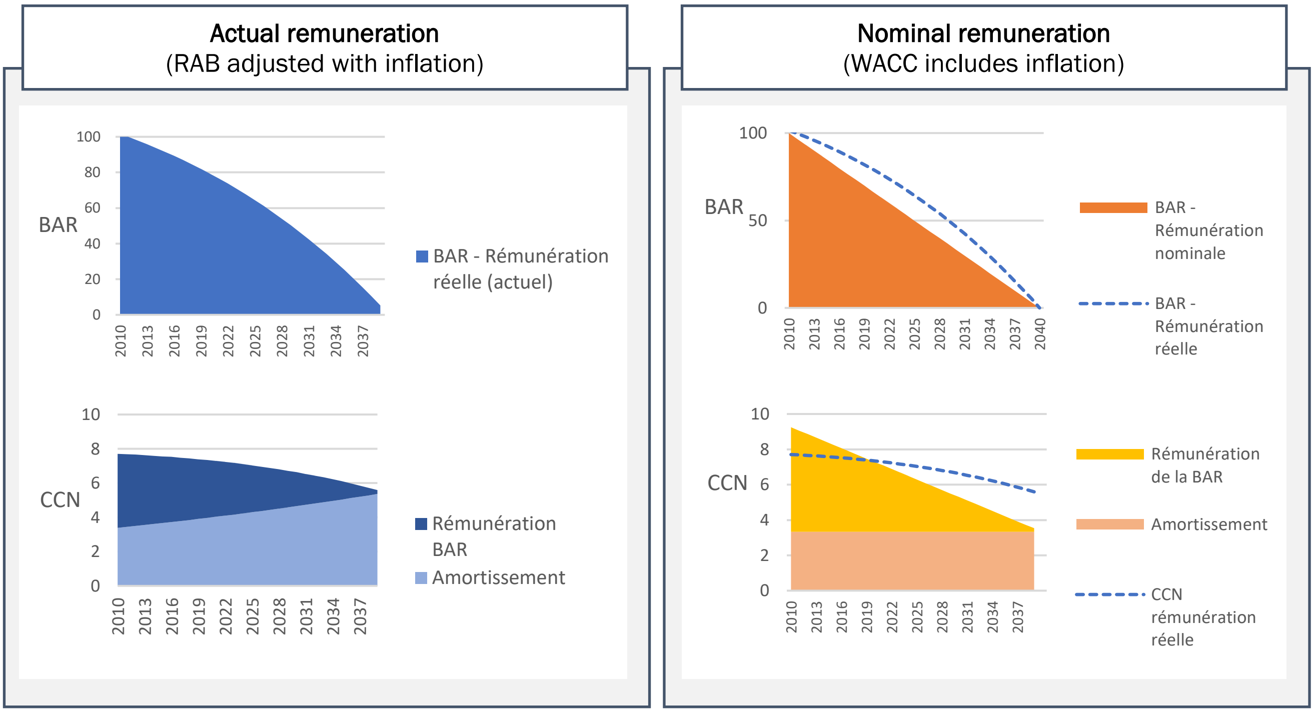
With regard to the optimised management of operators' assets, two suppliers questioned the concomitance of the rise in costs linked to the development of biomethane and the decrease in gas consumption, with the risk of a worsening of the price squeeze (scissor effect) and of biomethane becoming less acceptable, which could hinder its development.

3.7.4 Evolution towards nominal remuneration

Under the current gas infrastructure tariffs, the book value of the assets is revalued each year in line with inflation. This revalued asset base is associated with a remuneration set in real terms - i.e. adjusted for inflation, insofar as this is already taken into account in the value of the RAB.

In contrast, the electricity transmission infrastructure tariff (TURPE HTB) stipulates that the value of the asset base is the net book value of these assets. The associated remuneration is defined and set in nominal terms - i.e. with a risk-free rate that includes inflation.

Theoretical case of an asset commissioned in 2010 and depreciated over 30 years



In the case of real remuneration, indexing the RAB to inflation means that the cost of current inflation is passed on to future users of the infrastructure, since the depreciation gradually increases as inflation takes hold. This framework contributes to the gradual increase in the unit cost of transmission.

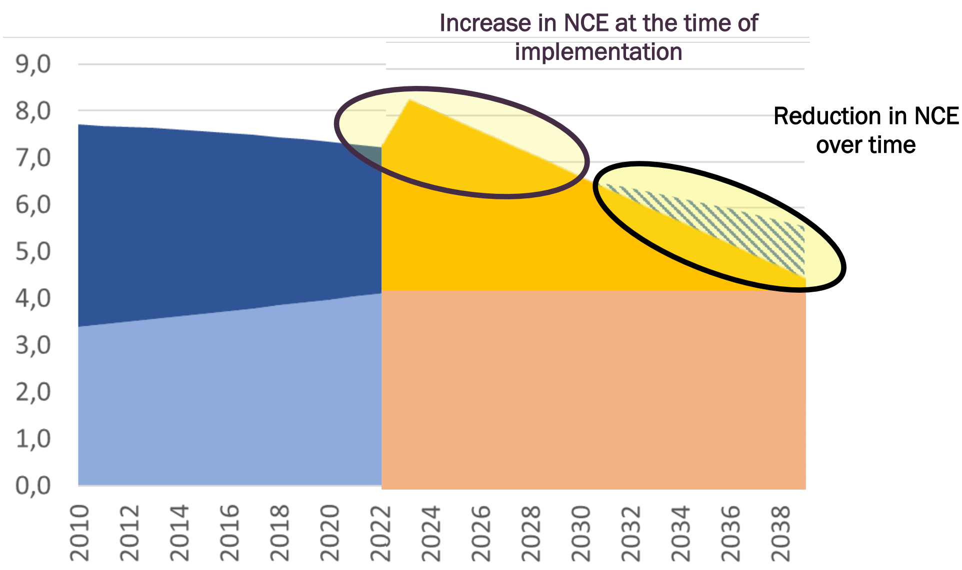
In the case of nominal remuneration, the effect of inflation is included in the WACC. Its impact on consumers is immediate. This method results in depreciation for a given asset that is constant over time. The WACC is higher and the proportion of NCE linked to remuneration is therefore greater in the short term.

The two remuneration methods are equivalent in the long term.

Effect of a change in method

With a switch to nominal RAB remuneration, inflation would be incorporated into the WACC and the value of the asset base would no longer be revalued by inflation each year.

Theoretical case - switch to nominal remuneration from 2024



CRE's preliminary analysis

This method of remunerating RAB assumes a higher WACC than in the case of RAB indexed to inflation. It leads to a temporary increase in the NCE when it is implemented, but these then fall as the level of the RAB is reduced more rapidly.

Such a change would make it possible to better control changes in the unit cost of transporting gas over time: at this stage, CRE considers that this is a relevant solution to address the risk of an increase in the unit cost of transporting gas over time. In addition, this development means that future users will not have to bear the cost of current inflation.

CRE notes, however, that this would mean a significant increase in the NCE when the method is changed. It could possibly be implemented gradually.

> Q29 : Do you consider that the proposal to end the indexation of the RAB on the inflation and to take it into account directly in the remuneration rate would provide a solution to the risk of an increase in the unit cost of transmission in the long term? Do you have any comments on its implementation (method, progressiveness, etc.)?

3.7.5 Changes in asset depreciation methods

The regulatory depreciation duration for an asset must be consistent with its expected useful life, in order to ensure that its cost is borne by the users benefiting from it throughout its lifetime.

For a given depreciation period, there are several ways of setting the rate of depreciation of an asset, the two main ones being as follows:

- straight-line depreciation: the annual depreciation payments are the same throughout the asset's life;
- degressive depreciation: depreciation instalments are higher at the beginning of the asset's life, then gradually decrease.

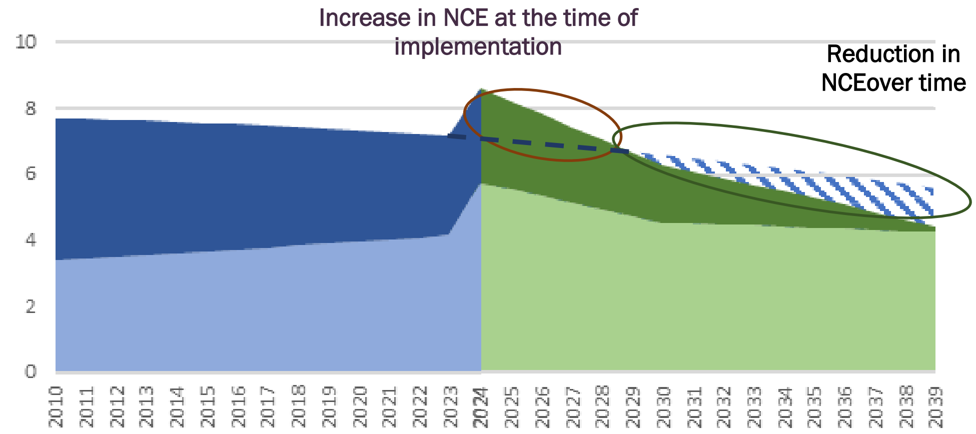
Under the current tariff framework, gas operators' assets are depreciated on a straight-line basis. This method is appropriate when use is expected to be stable over time. Conversely, degressive depreciation is useful for adapting depreciation charges to use that diminishes over time. Straight-line depreciation contributes to the gradual increase in unit transmission costs in the event of a sustained decrease in consumption: this depreciation method could be questioned in the current context of declining gas consumption.

3.7.6 Degressive depreciation

Effect of a change in method

This involves changing the depreciation distribution (while maintaining the same depreciation period) to take account of changes in the actual use of assets during a period of declining use.

NCE - Degressive balance depreciation based on changes in consumption* implemented in 2024



* According to scenario S1 of the Gas Futures study

CRE's preliminary analysis

At this stage, CRE believes that switching from straight-line to degressive depreciation is also an appropriate response to the risk of an increase in the unit cost of transporting gas. This would make it possible to maintain consistency between the useful life of the assets and their regulatory life, while rebalancing the distribution of capital charges over time in relation to the expected level of use of the assets. For example, accelerating the rate of depreciation of an asset without changing its useful life is consistent with the assumption that gas infrastructures will be used less and less but for longer beyond 2050. However, it is less suitable for assets whose economic life could be reduced or which could be converted to another use, such as hydrogen.

Finally, degressive depreciation generates higher NCE when it is implemented, but these decrease more quickly. Like the de-indexation of the RAB, this implies a temporary increase in NCE when the method is changed. An estimate of this increase is presented in section 3.7.9.

CRE believes that the depreciation factor chosen could be set so as to limit the increase in charges at the time of the change of method and re-evaluated at each tariff period, based on forecasts of changes in infrastructure use. This revision would also make it possible to maintain a rate of depreciation that is consistent with updated consumption forecasts, and thus reflect infrastructure use as closely as possible.

> Q30 : Do you think that changing the depreciation method would provide a solution to the risk of an increase in the unit cost of transmission over time?

3.7.7 Reduction of the depreciation period

Modifying the depreciation period for assets, where this is consistent with their expected useful life, is another way of ensuring that future users of the infrastructure bear less depreciation costs. Several operators have made requests to this effect in their tariff applications.

Operators' demand

TSOs propose to reduce the depreciation period for certain assets:

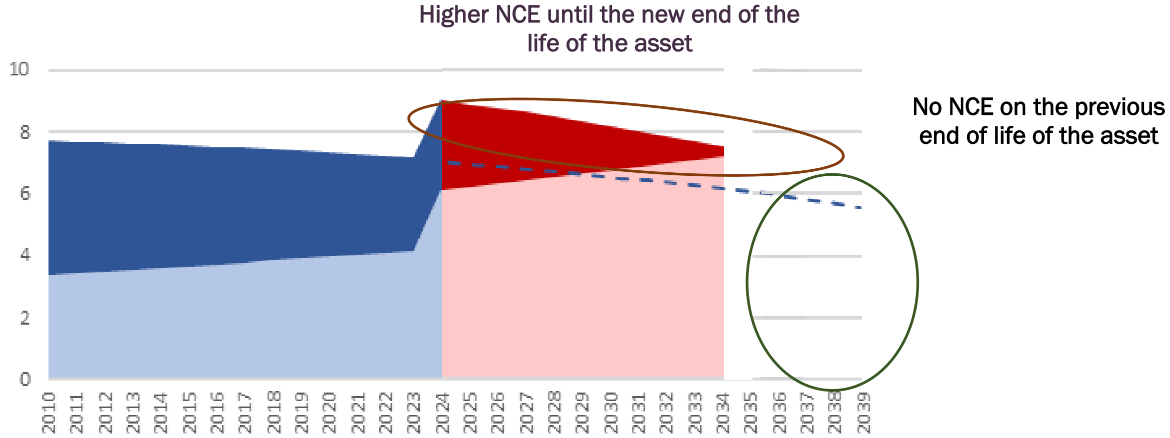
- GRTgaz proposes to reduce the depreciation period for new pipelines (from 50 to 30 years);
- Teréga proposes to reduce the depreciation period for new pipelines (from 50 to 30 years), as well as for new compressor stations and new delivery stations (from 30 to 25 years).

Effect of a change in method

This method greatly reduces the risk of stranded costs for a given asset, as it ensures that the asset's RAB will be zero at the end of its useful life, assuming that the new regulatory life corresponds to the actual useful life of the asset.

Reducing the depreciation period of an asset implies an increase in NCE over the remainder of its useful life.

NCE - Reduction in depreciation period from 30 to 25 years, applied in 2024



CRE's preliminary analysis

This method is relevant in the case of assets that are effectively at risk of no longer being used before the end of their regulatory life. CRE has already reduced the depreciation period for gas assets where there is a significant risk that they will no longer be used by the end of their regulated life: in the ATRD6 tariff, it decided to reduce the depreciation period for building connections and pipes from 45 to 30 years, in response to the same context of declining gas consumption. It also decided to reduce the depreciation periods for the Fos Tonkin[8] and Montoir[9] terminals, where there was a risk of non-subscription at the end of long-term contracts.

However, as the "Future of Gas" study illustrates, most gas infrastructures should remain in service beyond 2050. Reducing the lifespan of other assets would therefore lead to an inappropriate decorrelation between their regulatory lifespan and their economic lifespan. This decorrelation would not be favourable to the economic efficiency of the gas system, as it could limit the financial incentive for operators to maintain assets in service, and on the contrary encourage them to renew them prematurely.

CRE therefore considers at this stage that the relevant situations for applying this solution have already been the subject of the necessary adaptations (building connections and pipes in particular), and that it is not appropriate in the case of the majority of other French gas assets. It could, however, be applied in the case of assets that present a risk of non-use before the end of their regulatory life. For example, the depreciation period for new gas transmission pipelines could be reduced to 40 years in certain cases.

Q31 : Do you agree with CRE's analysis of the usefulness of reducing the depreciation period in response to the risk of an increase in the unit cost of transmission?

3.7.8 Financial incentives to keep assets in service

Operators' demand

Terćga proposes to introduce a regulatory mechanism to encourage the extension of asset life. This would take the form of a surcharge on operating costs attributable to depreciated assets, the level of which would depend on the age of the assets being exceeded beyond their regulatory life. This surcharge would be 30% of operating expenses for assets between 0 and 5 years older than their regulatory life, and would be capped at 100% of expenses for the oldest assets.

CRE's preliminary analysis

The current regulatory framework provides for remuneration of assets based on a normative regulatory lifetime: in some cases, this may be shorter than the actual lifetime of the assets. In these cases, the assets are operated by the operators without any additional remuneration. In order to limit the costs on end customers, CRE believes that operators should not base their decisions to replace assets on their level of depreciation. Instead, operators should decide to replace assets by carrying out a cost-benefit analysis of the possible costs of maintaining them in service compared with renewing them. In particular, CRE ensures that this principle is applied during the annual exercise to approve operators' investments.

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[8] CRE Deliberation of 13 December 2011 concerning the decision on the project to extend the life of the Fos Tonkin terminal beyond 1 October 2014

[9] Deliberation of the French Energy Regulation Commission of 7 January 2021 deciding on the tariff for the use of regulated LNG terminals

At this stage, CRE considers that Teréga's request for additional operating costs for fully depreciated assets could lead to over-remuneration of the assets, without bringing any certain financial benefit for the tariff. Indeed, the potential savings in capital costs made possible by this system remain uncertain. Furthermore, when applied in isolation, this system cannot prevent the early renewal of assets with any certainty.

Q32 : Do you agree with CRE's analysis of the financial incentive to keep depreciated assets in service?

3.7.9 Implementation of new features

CRE has estimated the impact of implementing nominal remuneration and diminishing balance depreciation.

- In the case of the switch to nominal remuneration, the estimate takes account of the application of this change to the entire RAB.
- Degressive depreciation is applied to all of the operator's assets. CRE assumes that depreciation will be 1.2 times straight-line depreciation. The increase in depreciation leads to a reduction in the RAB during the tariff period. The impact of this decrease is valued by taking into account a WACC in the middle of the range.

The impact on normative capital charges and on operators' allowed revenue is detailed in the following table:

On average over the tariff period	GRTgaz	Teréga	All operators
Nominal remuneration			
Changes in NCE	+6.6 %	+8.8 %	**+7.1 %**
Changes in Allocated revenue	+3.5 %	+6.0 %	**+3.8 %**
Degressive depreciation			
Changes in NCE	+11.0 %	+9.2 %	**+10.9 %**
Changes in Allocated revenue	+5.7 %	+6.3 %	**+5.9 %**

These changes will gradually reduce the RAB. The impact on operators' RAB in 2027 is detailed in the table below:

	GRTgaz	Teréga	All operators
Nominal remuneration			
mpact on the level of the RAB in 2027	-6.6 %	-6.4 %	**-6.6 %**
Degressive depreciation			
mpact on the level of the RAB in 2027	-5.2 %	-3.5 %	**-4.9 %**

The rate increase that would result from these changes in the method of remunerating assets could be mitigated to avoid excessive tariff increases:

- de-indexation of the RAB and accelerated depreciation could be implemented gradually, for example initially on new assets or asset categories by asset category;
- the degressive depreciation coefficient could be set so as to limit the increase in NCE in the short term.

Q33 : Do you think it would be advisable to implement these changes now?

Q34 : Do you have any other suggestions concerning the distribution of capital costs over time, with a view to meeting the risk of an increase in the unit cost of gas transmission?

4. LEVEL OF EXPENSES TO BE COVERED

4.1 Review of ATRT7: operating expenses

As an appendix to this public consultation, CRE is publishing an assessment of the tariff regulatory framework over the last 10 years, and in particular of changes in operating costs.

4.1.1 GRTgaz

Over the period 2020-2022, the net operating costs borne by GRTgaz were lower overall than the operating costs forecast in the trajectory set by the tariff.

Current M€	2020	2021	2022
Net operating costs in the ATRT7[10] tariff	790.6	782.8	835.0
Actual net operating costs	789.0	680.0	797.1
Difference	-1.5	- 102.8	- 37.9

Over the period 2020-2022, the cumulative difference between the ATRT7 tariff trajectory and the actual trajectory amounts to -€142.2 million, or -6% compared with the forecast trajectory, despite the exceptional events that took place during this period (Covid and the war in Ukraine).

The main variances are explained by:

- tax expenses below the forecast trajectory, due to the reduction in production taxes implemented from 2021 in order to improve the competitiveness of businesses;
- energy costs lower than forecast, due to a significant fall in the volume of gas and electricity consumed, particularly in 2021;
- higher-than-expected operating income, with the contracting of additional services (in particular with Storengy), and an increase in volumes of immobilised production;
- lower-than-expected operating and maintenance costs.

GRTgaz's net operating costs excluding energy were 4% lower than the forecast trajectory for the period 2020-2022.

Current M€	2020	2021	2022
Net operating costs excluding energy provided for in the ATRT7 tariff	694.8	695.2	744.3
Actual net operating expenses excluding energy	701.0	649.5	697.5
Difference	6.1	-45.7	-46.7

4.1.2 Teréga

Over the period 2020-2022, the net operating costs borne by Teréga were lower overall than the operating costs forecast in the trajectory set by the tariff.

Current M€	2020	2021	2022
Net operating costs in the ATRT7[11] tariff	81.3	80.2	79.7
Actual net operating cost	71.1	69.3	72.3
Difference	-10.3	-10.4	-7.4

Over the period 2020-2022, the cumulative difference between the ATRT7 tariff trajectory and the actual trajectory amounts to - €28.1 million, or - 12% compared with the forecast trajectory, despite the exceptional events that took place during this period (Covid and the war in Ukraine).

The main variances are explained by:

[10] The trajectories for energy, CO2 and consumables charges were updated each year. The trajectories for other charges were set at the beginning of the tariff period, and updated each year to take into account the difference between forecast inflation and actual inflation.

[11] The trajectories for energy, CO2 and consumable costs have been updated each year. The R&D trajectory was updated halfway through the tariff period. The trajectories for other costs were set at the beginning of the tariff period, and updated each year to take into account the difference between forecast inflation and actual inflation. Finally, this trajectory takes into account the change in classification of certain Teréga expenses from OPEX to CAPEX from 2022.

- tax expenses below the forecast trajectory, due to the reduction in production taxes implemented from 2021 in order to improve the competitiveness of businesses;
- operating and maintenance costs lower than forecast, due to lower expenditure on storage costs and the "Health, Safety, Security, Environment, Quality and Sustainable Development" cost item;
- lower-than-expected overheads, due to lower travel expenses and lower-than-expected intra-group services.

Teréga's net operating expenses excluding energy were 12% lower than the forecast trajectory for the period 2020-2022.

Current M€	2020	2021	2022
Net operating costs excluding energy provided for in the ATRT7 tariff	73.5	74.4	72.3
Actual net operating expenses excluding energy	65.4	64.2	64.9
Difference	-8.1	-10.2	-7.4

4.2 Operators' demands and main challenges associated

4.2.1 GRTgaz

In its tariff application, GRTgaz anticipates a prolongation of the energy crisis over the ATRT8 period, and its consequences for its business, with significant congestion management costs and high energy price volatility.

In addition, GRTgaz believes that the decrease in gas consumption observed since the war in Ukraine could continue, as a result of efforts to reduce consumption and the objectives of reducing greenhouse gas emissions. GRTgaz also expects a significant drop in capacity subscriptions to the French Interconnexion points (IPs), due to the expiry of many long-term capacity subscriptions, which will only be partially replaced by medium- and short-term contracts.

In this context, GRTgaz states that its tariff request aims to meet the following challenges:

- supporting the development of renewable gases: GRTgaz anticipates an increase in the rate of connection of biomethane production units, and additional requirements for monitoring gas quality;
- guaranteeing the industrial safety and security of installations, by taking account of the new obligations arising from the multi-fluid decree, and of cyber-security requirements;
- strengthening its contribution to security of supply;
- reducing its carbon and environmental footprint, in particular by cutting methane emissions and controlling its energy consumption for compressors.

GRTgaz has also included performance actions in its tariff request.

Taking into account the challenges listed above, GRTgaz is requesting total net operating and capital costs of around €2,220 million per year on average for the ATRT8 period, an increase of 27% compared with the ATRT7 period.

The allowed revenue[12] corresponding to GRTgaz's demand increases by 32% in 2024 compared to the 2023 updated allowed revenue.

4.2.2 Teréga

In its tariff request, Teréga identifies the ATRT8 period as one of transition and securing. Teréga plans to strengthen the resilience of its industrial facilities and its IT system to guarantee security of supply, while preparing to welcome renewable gases as part of the energy transition.

In this context, Teréga states that its tariff request aims to respond to the following challenges:

- The structural inversion of flows at Pirineos following the outbreak of the Russo-Ukrainian war. The end of the long-term contracts at Pirineos has also limited visibility on the collection of its allowed revenue and increased its exposure on its capacity subscription assumptions;
- The overall rise and volatility of energy prices, generating an increase in network operating costs and greater exposure to market prices;

[12] Allowed revenue includes NCE, NOE, the CRCP reconciliation and, for 2023, certain smoothing terms and inter-operator transfers (repayments).

- Maintaining the company's regulatory compliance and safety to ensure the long-term performance and resilience of its facilities;
- Preparing for the energy transition, so that the network is ready for the injection of low-carbon gases such as biomethane, H_2 and CO_2.

Taking into account the challenges listed above, Teréga is requesting total net operating expenses and capital costs of around €302 million per year on average for the ATRT8 period, an increase of 26% compared with the ATRT7 period.

The allowed revenue[13] corresponding to Teréga's demand increases by 10% in 2024 compared with the updated 2023 allowed revenue.

4.3 Net operating expenses

To set the trajectories for operators' net operating costs, CRE uses the following inflation assumptions:

	2023	2024	2025	2026	2027
CPI (excluding tabacco)	4.60%	2.40%	1.80%	1.60%	1.60%

These assumptions will be adjusted with the latest forecasts available at the time of the tariff decision..

4.3.1 Operators' demand

4.3.1.1 GRTgaz

The forecast net operating costs presented by GRTgaz in its request for the ATRT8 tariff period (2024-2027) are as follows:

Current M€	2022 actual	2024	2025	2026	2027
Net operating costs	797.1	1176.3	1079.7	1080.9	1074.8

GRTgaz's request assumes a sharp increase in net operating costs (including energy costs) between 2022 and 2024, of €379 million (i.e. +48%). Net operating costs would then fall by around 3% per year on average over the period 2024-2027. Excluding energy, the increase between the 2022 actual and the 2024 request is 36%.

The main items in GRTgaz's demand that will change between 2022 and 2024 are as follows:

- “Energy" (€127 million increase, or +128%): GRTgaz anticipates an increase in fuel gas consumption expenses, mainly due to higher prices;
- “H/B Conversion" (€90 million increase, or +160%): GRTgaz expects an increase in costs related to the H gas to L gas conversion offer to Zone B suppliers in France, due to the increase in the spread between Dutch and French market prices;
- “Salaries” (€50million increase, or +15%): this increase is mainly due to the revaluation of salaries following the rise in inflation;
- “Operation and maintenance" (€30 million increase, or +25%): this increase is mainly due to inflation and the additional expenditure anticipated by GRTgaz with a view to implementing the future regulation aimed at reducing methane emissions from the energy sector.

4.3.1.2 Teréga

The projected net operating expenses presented by Teréga in its request for the ATRT8 tariff period (2024-2027) are as follow:

Current M€	2022 actual	2024	2025	2026	2027
Net operating costs	72.3	101.6	103.4	103.6	105.5

[13] Allowed revenue includes NCE, NOE, the CRCP reconciliation and, for 2023, certain smoothing terms and inter-operator transfers (repay-ments).

Teréga's request assumes a sharp increase in net operating costs (including energy costs) between 2022 and 2024, of €29 million (i.e. + 41%). Net operating costs would then rise by an average of around 1% per year over the period 2024-2027. Excluding energy, the increase between the 2022 actual and the 2024 request is 39%.

The main items in Teréga's demand that will change between 2022 and 2024 are as follows:

- "Operation and maintenance" (€13million increase, or +52%): this increase is mainly due to the additional expenditure anticipated by Teréga to implement the future regulation aimed at reducing methane emissions from the energy sector, and to the creation of a new maintenance OPEX envelope for depreciated assets.
- "Staff costs (€5million increase, or +12%): this increase is due to the revaluation of salaries following the rise in inflation and the addition of new FTEs (full-time equivalents);
- "Energy" (4million increase, or +58%): Teréga anticipates an increase in expenses related to fuel gas consumption, mainly due to higher prices;
- "Congestion management costs" (€3million increase, or +84%): Teréga anticipates an increase in congestion management costs based on costs observed during the winter of 2022-2023.

4.3.2 Challenges identified by CRE and analysis approach adopted

CRE has asked operators to present their tariff requests in the light of the most recent figures, justifying any significant variance from the 2022 figure and breaking down each item to the first euro, in order to ensure that any additional requirements cannot be covered by resources released from actions that are coming to an end.

CRE commissioned H3P-ORCOM to carry out an audit of the operating costs of natural gas transmission system operators. The work was carried out between April and July 2023. The auditor's report, based on the operators' updated request, is published for each operator at the same time as this public consultation document.

This audit provides CRE with a clear understanding of the operators' operating costs and income for the ATRT7 period and the forecast operating costs presented by the operators for the coming tariff period (2024-2027). The purpose of this audit is to:

- provide an expert opinion on the relevance and justification of the operators' operating cost trajectory for the next tariff period;
- to assess the level of actual costs (2020-2022) and forecast costs (2024-2027);
- make recommendations on the efficient level of operating costs to be taken into account for the ATRT8 tariff.

CRE also analysed certain specific items, in particular Research and Development (R&D) expenses, energy costs, costs linked to the mechanism for converting H-gas into L-gas and costs linked to congestion management in the French market area.

4.3.3 Summary of audit results and CRE's additional adjustments to certain items

4.3.3.1 GRTgaz

- **Results of the external audit**

The scope of costs audited by the auditor includes net operating expenses, excluding the following items audited by CRE: energy, R&D, expenses related to congestion management mechanisms and the interruptibility mechanism, flexibility, stored gas WCR and expenses related to the H-gas to L-gas conversion offer.

Based on these costs, the auditor recommended the following trajectory for GRTgaz over the ATRT8 period:

Current M€	2022 actual	2024	2025	2026	2027
Trajectory requested by GRTgaz	563.4	712.2	745.4	796.3	825.1
Actual 2022 discounted		603.4	614.1	623.9	633.6
Auditor's trajectory		599.5	621.0	621.3	618.9
Impact on GRTgaz's demand		-112.7	-124.4	-175.0	-206.2

The adjustments recommended by the auditor relate mainly to staff costs, the industrial system, operational support and operating income. These adjustments are broken down as described below.

Staff costs

GRTgaz expects to increase its workforce over the ATRT8 period (by more than 80 additional FTEs in 2027 compared with 2022), mainly as a result of the development of green gas (around 30 additional FTEs) and changes in the regulations on methane emissions (around 100 additional FTEs), partly offset by productivity gains of 0.5% per year (around sixty fewer FTEs, due to retirements and internal transfers, for example).

Among the main adjustments in volume, the auditor does not consider the increase in headcount related to the regulation on methane emissions at this stage. In fact, as indicated in section 3.3.1.2, CRE plans to set the trajectory of operating costs linked to the application of the European regulation on the reduction of methane emissions, as well as the regulatory framework for the gas operators concerned, once the European regulation on the reduction of methane emissions from the energy sector has been adopted. With regard to the additional requirements linked to the development of green gas, the auditor considers that only part of the operator's initial request is justified, given the forecasts for the installation of biomethane injection and backhaul stations (around fifteen FTEs retained).

As regards the price effect, the auditor uses different assumptions for changes in the wage bill from those used by GRTgaz, in particular a GVT (“*glissement vieillesse technicité*”) and the National Base Salary.

The auditor's volume and price adjustments represent a cumulative reduction in costs of around €139 million over the ATRT8 period.

The auditor has also made a downward adjustment of around €21 million to the charges relating to the ANE (Avantage en Nature Energie) in the light of changes in energy prices on the markets, and taking into account forecast energy consumption that has been revised downwards as a result of the sobriety efforts required of all French people.

In total, the auditor therefore proposes downward adjustments to GRTgaz's request for personnel-related costs of -€44.7 million on average per year (i.e. a cumulative total of -€178.9 million over the ATRT8 period), mostly as a result of taking into account a lower number of new posts created over the period.

Industrial system

The auditor adjusted the requested trajectory downwards because GRTgaz considers the 2022 actual as a base of expenses to which is added non-recurring expenses anticipated between 2024 and 2027, but without subtracting non-recurring expenses occurring in 2022. Consequently, the auditor has constructed an expense trajectory for the Industrial System by indexing the expenses incurred between 2020 and 2022 to inflation and by only adding expense assumptions for the programmes if he had sufficient information to consider that they were not included in the actual expenses between 2020 and 2022 (major maintenance and servicing programmes for compressor stations and new biomethane stations considered relevant).

As indicated above, the auditor did not include the costs associated with the draft regulation on methane emissions, which will be dealt with at a later date.

This results in a downward adjustment of -€40.3 million per year on average (i.e. -€161.3 million cumulatively over the ATRT8 period) on industrial system costs, with GRTgaz's demand rising sharply (€217 million/year on average over the ATRT8) compared with the 2022 actual (€156 million/year).

Operational support

With regard to the Information System item, the auditor considers that GRTgaz has provided numerous quality elements, which are nevertheless insufficient to quantitatively reconstitute the load trajectory requested by GRTgaz and to analyse it in relation to the 2022 actual. In particular, the auditor understands that each IT expense line was constructed independently by the team responsible, on the basis of their own knowledge and forecasts. The IT expense trajectory has therefore not been constructed on the basis of a set of common assumptions. In addition, GRTgaz has built this IT cost trajectory from 2024 to 2027 using its forecast expenditure for 2023 as a reference, rather than actual expenditure for 2022.

As a result, in order to ensure that changes are consistent with actual 2022, the auditor has constructed a trajectory for the Information System item that has been adjusted downwards by approximately -€100 million over the ATRT8 period by indexing actual recurring expenses for the period 2020-2022 to inflation, and by excluding certain provisions linked to contract renegotiations (considered to be covered by inflation). On the other hand, the auditor accepted GRTgaz's requests for non-recurring expenses relating to clearly identified projects.

With regard to the Property item, GRTgaz has constructed its trajectory with the general application of the inflation rate for rents and provides for a readjustment in the level of general services. The auditor has constructed its trajectory by indexing rents to the average change over the last 10 years in the Tertiary Activity Rent Index (ILAT), justifying that this is the benchmark index for commercial and industrial leases and that the fact of using the average change over the last 10 years makes it possible to neutralise exceptional and non-normative fluctuations.

The result is a downward adjustment of -€35.5 million per year on average (i.e. -€141.6 million cumulatively over the ATRT8 period) on operational support costs, as GRTgaz's demand has risen sharply (€182 million per year on average over the ATRT8) compared with the 2022 figure (€146 million per year).

Operating income

The auditor has constructed the revenue trajectory on the basis of assumptions that differ from those of GRTgaz.

In particular, the auditor considers that the rate of growth in royalties and biomethane studies observed between 2020 and 2022 will remain stable until 2024. From 2025 onwards, the auditor bases his trajectory on the forecasts for changes in the number of commissioning of biomethane facilities submitted by the operator. This adjustment represents an increase of approximately €40 million over the ATRT8 period compared with GRTgaz's request (which, on the contrary, forecasts relatively stable revenue compared with the actual figure for 2022).

The auditor also included certain operating revenues that GRTgaz had not taken into account (in particular revenues from works and reimbursable services relating to the MAGEO and Seine Nord Canal projects, the development of which during ATRT8 is deemed likely and which GRTgaz has taken into account in its normative capital expenses trajectory). This adjustment represents approximately €35 million over the ATRT8 period compared with GRTgaz's request.

The auditor also adjusts the average hourly rate assumption used by GRTgaz to calculate its capitalised production, in line with the price effect assumption used for the development of personnel costs (i.e. an increase of €12 million over the ATRT8 period compared with GRTgaz's request).

The result is an overall upward adjustment in operating income of €29.5 million per year on average (i.e. €117.8 million cumulatively over the ATRT8 period), with GRTgaz's demand being lower (€188 million per year on average over the ATRT8 period) than in 2022 (€195 million per year).

- **CRE's adjustments**

Energy costs

GRTgaz's request for energy costs (gas, electricity, CO_2, excluding biomethane) is based on the assumption of a reversal in the pattern of gas flows, from south to north, significant LNG inflows, and a sustained level of IP outflows.

GRTgaz's demand	2022 actual	2024	2025	2026	2027
Gas (M€) *Volumes (GWh)*	52.5 *2 334*	165.9 *2 445*	117.7 *2 378*	91.1 *2 270*	69.9 *2 010*
Electricity (M€) *Volumes (GWh)*	*34.5* *306*	37.5 *236*	34.6 *236*	*32.9* *236*	32.6 *241*
CO_2 (M€)	5.4	16.0	16.6	16.0	13.9
TIC[14] (M€)	7.0	6.5	6.3	5.7	4.7
Total energy charges (M€)	99.2	225.9	175.2	145.7	121.0

CRE's preliminary analysis

On the basis of flow assumptions consistent with those envisaged for Teréga's energy charges, CRE plans to make several adjustments to this request, in particular:

- a downward adjustment of the differences between the quantities of gas exiting and entering GRTgaz's network (EBT). As consumption volumes for this item are particularly volatile and difficult to predict, CRE has adopted the average volume recorded over the ATRT7 period (including the estimated value by GRTgaz for 2023), i.e. 782 GWh/year. This adjustment results in a reduction of 339 GWh/year, or €64.3 million, compared with GRTgaz's request over the ATRT8 period;
- a downward adjustment to the price of CO_2 allowances, based on common price assumptions and changes in the allocation of free allowances, in line with European allocation rules. This adjustment results in a reduction of €13.1 million compared with GRTgaz's request over the ATRT8 period.

[14] Internal consumption tax

These assumptions lead to a downward adjustment of GRTgaz's demand of around - €77.4 million in cumulative terms over the ATRT8 period, i.e. a reduction of around 12%. These adjustments may change further to take account of energy price trends between now and the final decision.

CRE's preliminary trajectory	2022 actual	2024	2025	2026	2027	ATRT8
Gas (M€) *Volumes (GWh)*	52.5 *2 334*	142.3 *2 098*	102.1 *2 062*	78.0 *1 946*	57.8 *1 744*	**380.2** *7850*
Electricity (M€) *Volumes (GWh)*	*34.5* *306*	37.5 *236*	34.6 *236*	*32.9* *236*	32.6 *241*	**137.6** 949
CO_2 (M€)	5.4	13.0	13.4	12.7	10.5	**49.5**
TIC (M€)	7.0	6.5	6.3	5.7	4.7	**23.3**
Total energy charges (M€)	99.2	199.3	156.4	129.3	105.5	**590.4**

<u>R&D</u>

With regard to R&D, GRTgaz's expenses over the period 2020-2022 (€92 million, including €45.7 million in external charges) was higher than the trajectory set by CRE (€83 million, including €46.1 million in external charges). GRTgaz explains this by higher labour costs than forecast in the trajectory, insufficiently offset by higher revenues than the tariff trajectory. External charges was in line with the trajectory set by CRE.

GRTgaz is requesting an R&D budget of €139 million for the ATRT8 period around 50% higher than the costs incurred between 2020 and 2022. This includes €67.3 million in external costs, €106.9 million in labour costs, and €35 million in revenue. GRTgaz's budget is divided into five aims, to which are added specific actions linked to innovation, and a range of operational expertise:

- optimising functioning, operation and safety;
- reducing environmental impact ;
- preparing networks for the arrival of new gases;
- preparing networks for hydrogen;
- projects relating to energy forecasting, management and optimisation.

Labour costs and revenues were analysed and adjusted by the auditor. CRE presents below its preliminary analysis of external costs. In its tariff decision, CRE nevertheless plans to apply the same principles to adjust these various amounts.

CRE's preliminary analysis

For some programmes, GRTgaz's anticipated expenditure trajectories are increasing over the ATRT8 period, without the TSO having justified these trends.

CRE is considering the following adjustments for the lower limit:

- at this stage, the increase in the "innovation" item over the ATRT8 period is not sufficiently justified by GRTgaz, and CRE therefore plans to retain the amount spent by GRTgaz on this item over the ATRT7 period, increased by inflation;
- CRE analyses that the "gas analysis" item is presented twice in the R&D budget request, without any precise justification for this double counting. In addition, the item "qualification of network and measurement equipment" represents research carried out on behalf of a third-party operator, but does not show any associated revenue. As a result, CRE does not intend to retain a budget for these two items;
- GRTgaz does not provide sufficient justification for the expenditure related to the emergence of pyrogasification and hydrothermal gasification processes and to support for the technological development of methane pyrolysis. In addition, CRE associates certain expenditure with support for the development of production facilities that are not directly part of a TSO's remit. As a result, CRE is considering at this stage not to retain the amounts for these projects over the period;

- CRE is also considering not including the expenditure relating to the programme to study the atmospheric pollutants of vehicles running on NGVs, as this is not directly part of the remit of a TSO and is not intended to be covered by the tariff.

As a result, CRE is considering a trajectory of external R&D expenses representing €54.0 million over the ATRT8 period, i.e. €13.5 million per year on average, compared with expenses of €15.2 million per year on average over the ATRT7 period.

Current M€	2022 actual	2024	2025	2026	2027
GRTgaz's requested trajectory	14.9	17.1	17.7	16.5	16
GRTgaz's preliminary trajectory		13.9	13.7	13.4	12.9
Impact on GRTgaz's demand		-3.2	-4.0	-3.1	-3.1

<u>Expenses related to congestion management mechanisms</u>

The congestion observed on the TRF (Trading Region France) during the winter of 2022/2023 led to a sharp increase in congestion absorption costs for TSOs. These are linked to the activation of the locational spread, with €54.6 million spent during the winter of 2022/2023 (for a total volume of 5.1 TWh).

The load trajectory proposed by GRTgaz in its tariff application is high, and assumes loads of the same order of magnitude as those for the winter of 2022/2023 until 2027.

CRE's preliminary analysis

CRE notes that GRTgaz's forecast charges for the period 2024-2027 are not consistent with the operator's congestion volume assumptions presented in particular in the CRE's public consultation on mechanisms for managing south to north congestions on the gas transmission networks in June 2023[15] (i.e. around 3.5 TWh/year on average over the period). CRE has also chosen a purchase price that is consistent with the price spreads between the French market and the Dutch market, which is a possible source of gas in the event of congestion.

CRE's preliminary trajectory results in a downward adjustment of GRTgaz's demand of -€168.6 million over the ATRT8 period, i.e. -€42.1 million/year.

Current M€	2022 actual	2024	2025	2026	2027
GRTgaz's requested trajectory	30.7	48.4	48.4	48.4	48.4
CRE's preliminary trajectory		7.9	6.8	5.7	4.6
Impact on GRTgaz's demand		-40.5	-41.6	-42.7	-43.8

<u>WCR of stored gas</u>

GRTgaz proposes to remunerate the working capital requirement for stored gas at the level of the WACC (4.65% in the operator's application).

CRE's preliminary analysis

CRE considers that the remuneration of a stock such as gas corresponds to a fixed asset, which should therefore be remunerated at the rate for fixed assets in progress.

This leads to a downward adjustment of €9.3 million over the ATRT8 period compared with GRTgaz's request.

Current M€	2022 actual	2024	2025	2026	2027
GRTgaz's requested trajectory	4.3	6.7	5.5	4.3	3.6

[15] see appendix 3 of Public consultation no. 2023-05 of 15 June 2023 on mechanisms for managing south to north congestions on the gas transmission networks

CRE's preliminary trajectory		4.0	3.3	2.5	2.2
Impact on GRTgaz's demand		-2.7	-2.2	-1.7	-1.5

- **Preliminary analysis summary**

GRTgaz's request would lead to a 36% increase in non-energy operating costs in 2024 to be covered by the ATRT8 tariff, compared with the level of costs recorded in 2022.

At this stage of its analyses, CRE considers that the TSO's request is not sufficiently justified and is therefore too high.

The conclusions of the audit report gave rise to an adversarial discussion with GRTgaz in July 2023. GRTgaz was thus able to comment on the results of the consultant's work, and questioned some of the adjustments identified by the consultant in the course of this discussion.

The level finally adopted by CRE will depend on the results of the analyses currently underway on the adjustments recommended by the auditor, and on any other adjustments envisaged by CRE.

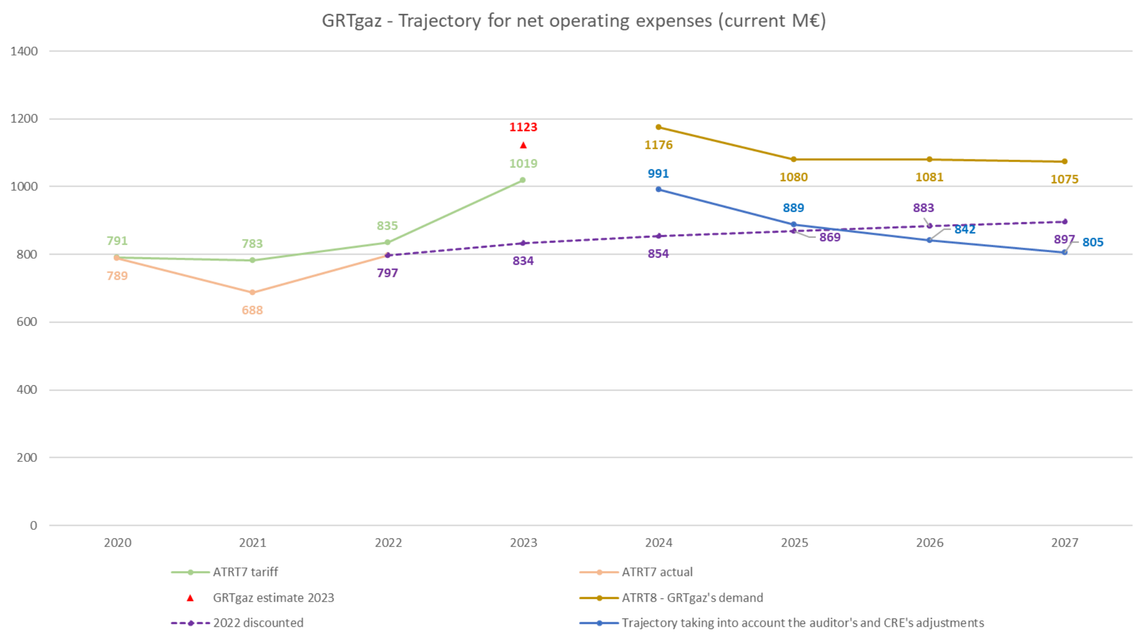
At this stage, CRE considers that the level of operators' net operating costs could fall between a "upper limit" corresponding to GRTgaz's request, and a "lower limit" established on the basis of all the conclusions of the external audit of the TSO's net operating costs and the adjustments considered by CRE and presented above.

For GRTgaz, the lower limit varies between €990.5 million in 2024 and €804.7 million in 2027, i.e. an average of €881.5 million over the period, and the upper limit varies between €1,176.3 million in 2024 and €1,074.8 million in 2027, i.e. an average of €1,102.9 million over the period.

These average levels are still higher than the €797.1m recorded in 2022:

- upper limit: growth from 2022 to 2024 of +48% (+36% excluding energy) and an average annual growth rate from 2024 to 2027 of -3%.
- lower limit: growth between 2022 and 2024 of +24% (+13% excluding energy) and an average annual growth rate between 2024 and 2027 of -7%.

The possible trajectories for net operating cost levels are as follows



4.3.3.2 Teréga

- **External audit's results**

The scope of costs audited by the auditor includes net operating expenses, excluding the following items audited by CRE: energy, R&D, and expenses related to congestion management and interruptibility mechanisms.

Based on these costs, the auditor recommended the following trajectory for Teréga over the ATRT8 period:

Current M€	2022	2024	2025	2026	2027

	actual				
Trajectory requested by Teréga	58.1	72.7	72.7	73.9	76.1
Actual 2022 discounted		62.2	63.3	64.3	65.3
Auditor’s trajectory		58.1	58.5	59.0	60.6
Impact on Teréga's demand		-14.6	-14.2	-14.9	-15.5

The main adjustments recommended by the auditors relate to structure costs, operating and maintenance costs, staff costs and operating income. These adjustments are broken down as described below.

Operating income

The main adjustments proposed by the auditor concern the "other income" item, comprising intra-group services and services to third parties.

These services cannot be predicted several years in advance, and Teréga uses a fixed amount of €0.1 million per year. For its part, the auditor has constructed the trajectory of the sub-item by indexing the 2020-2022 actual on inflation, justifying that even if these services are not very predictable, this construction is more robust than the one proposed by Teréga.

The result is an upward adjustment to operating income of €1.8m per year on average (i.e. a cumulative impact of €7m on net expenses over the ATRT8 period).

Operating and maintenance costs

Teréga has requested coverage of the operating costs associated with the application of the European regulation on the reduction of methane emissions. As indicated in section 3.3.1.2, CRE plans to set the cost trajectory and the regulatory framework for the gas operators concerned once the draft European regulation on reducing methane emissions from the energy sector has been adopted. The auditor therefore dismisses these charges at this stage.

The auditor has also ruled out voluntary carbon offsetting, requested by Teréga, which is a choice made by Teréga that is not directly included in the essential expenses for carrying out its TSO missions.

Finally, the auditor ruled out the request for additional OPEX for fully depreciated assets, which corresponds to a request for changes to Teréga's regulatory framework that CRE does not intend to adopt at this stage (see section 3.7.8).

The trajectory proposed by the auditor is therefore in line with the 2022 actual in current euros on average over the ATRT8 period.

This results in a downward adjustment of -€6.5 million per year on average (i.e. -€26 million cumulatively over the ATRT8 period) for operating costs, network maintenance, studies and other operating-related expenses, as Teréga's demand is up sharply (€37 million/year on average over the ATRT8 period) compared with the 2022 actual (€26 million).

Staff costs

Teréga's request includes new FTEs (transmission and storage combined) from 2024 for new needs over the next tariff period (CO_2, H_2, methane emissions, cybersecurity, asset management, regional institutional relations). The auditor considers that only some of the additional FTEs are justified, as the others are not essential for carrying out its TSO missions because they relate to non-regulated activities and Teréga has room for manoeuvre to redeploy its current resources (retirements, internal mobility, etc.). As with operating expenses, the auditor did not include expenses related to the regulation on methane emissions, which will be dealt with at a later date by CRE.

Concerning the price effect, the auditor uses different assumptions from Teréga.

This results in a downward adjustment of -1.7 M€ per year on average for transmission (i.e. -7 M€ cumulatively over the ATRT8 period) on personnel costs.

Structure costs

In its tariff application for the 2024-2027 ATRT8 period, Teréga included an inflation lag of one year, justifying that inflation in year N mainly impacts expenses in year N+1. The auditor did not consider this request to be relevant, particularly in view of the tariff framework which protects TSOs from changes in year N, and therefore did not include this proposal in its trajectory.

With regard to the endowment fund requested by Teréga, the auditor considers that this is a corporate choice that is specific to Teréga, and that this decision is not essential to the conduct of its TSO missions. The auditor does not accept this.

This results in a downward adjustment of €3.2 million per year on average (i.e. €13 million cumulatively over the ATRT8 period) on operating income, with Teréga's demand (€15.7 million/year on average over the ATRT8 period) being higher than the 2022 actual (€11.6 million).

- CRE's adjustments

Energy costs

Teréga's request for energy charges (gas, electricity, CO_2) is based on the assumption that the gas flow pattern will be reversed, from South to North, and that Teréga's gas consumption for its compression needs will be replaced by electricity consumption. Teréga's request also includes the TICPE tax (“*Taxe Intérieure sur la Consommation de Produits Energétiques*”) and purchases of CO_2 quotas.

Teréga's demand	2022 actual	2024	2025	2026	2027	ATRT8
Gas (M€)	1.1	4.9	5.3	5.3	5.2	**20.6**
Volumes (GWh)	*83.7*	*162*	*162*	*162*	*162*	*648*
Electricity (M€)	5.4	5.4	4.6	5.4	5.2	**20.6**
Volumes (GWh)	*33.2*	*31.7*	*31.7*	*32.9*	*34*	130.4
CO_2 (M€)	0.2	0.9	1.0	1.2	1.3	**4.4**
TIC (M€)	0.4	0.4	0.4	0.4	0.4	**1.7**
Total energy charges (M€)	7.2	11.6	11.3	12.3	12.1	**47.3**

CRE's preliminary analysis

On the basis of flow assumptions that are consistent with those envisaged for GRTgaz's energy costs, CRE plans to make several adjustments to this request, in particular :

- a downward adjustment of the EBT trajectory. As consumption volumes for this item are particularly volatile and difficult to predict, CRE has adopted the average volume recorded over the ATRT7 period (including the estimated value for 2023), i.e. 20.2 GWh/year. This adjustment results in a reduction of €3.2 million compared with Teréga's request for the ATRT8 period;
- a downward adjustment to the price of CO_2 allowances based on common price assumptions and changes in the allocation of free allowances. This adjustment results in a reduction of €0.7 million compared to Teréga's request over the ATRT8 period.

These assumptions lead to a downward adjustment in Teréga's demand of around - €4 million in cumulative terms over the ATRT8 period, i.e. a fall of around 8%. These adjustments may change further to take account of changes in energy prices.

CRE's preliminary trajectory	2022 actual	2024	2025	2026	2027	ATRT8
Gas (M€)	1.1	4.1	4.4	4.5	4.4	**17.4**
Volumes (GWh)	*83.7*	*137*	*137*	*137*	*137*	*548*
Electricity (M€)	5.4	5.4	4.6	5.4	5.2	**20.6**
Volumes (GWh)	*33.2*	*31.7*	*31.7*	*32.9*	*34*	130.4
CO_2 (M€)	0.2	0.8	0.9	1.0	1.0	**3.7**

TIC (M€)	0.4	0.4	0.4	0.4	0.4	**1.7**
Total energy charges (M€)	7.2	10.7	10.3	11.3	11.0	**43.4**

<u>R&D</u>

As regards R&D, Teréga's expenditure between 2020 and 2022 (€4.5million) was lower than the trajectory set by the CRE (€4.9m). Teréga explains this underachievement by the transfer of operating expenses to investment expenditure and by the uncertainty inherent in R&I projects.

For the ATRT8 period, Teréga is requesting an R&D budget (excluding staff[16]) of 28,3 M€ (7.1 million per year on average over the period, an increase of 316% compared with the ATRT7), divided into six aims and two projects:

- Integrity, performance and operational safety;
- Reducing our environmental footprint;
- Renewable methanes ;
- Hydrogen ;
- Multi-energy systems;
- CCUS, CO_2 capture, storage, transport and recovery;
- Feasibility studies for the Hysow project, which involves developing infrastructures for transporting H_2 and storing it in salt caverns;
- The Pycasso project studies the development of CO_2 transport infrastructures.

CRE's preliminary analysis

At this stage, CRE is considering the following adjustments:

- for the following items, CRE considers at this stage that the link is insufficiently established with the regulated missions of natural gas transmission, and therefore excludes them from its lower limit:
  - R&D budgets relating to feasibility studies for the Pycasso (CCUS) and HYSOW (Hydrogen) projects;
  - the project to implement a pilot project to convert 100m of a pipeline into H_2;
  - the item "new materials or alternatives to pipelines for transporting H_2 in a way that is technically and economically more competitive than transporting it in the form of gas through steel pipelines";
  - R&D budgets for "making CO_2 capture, transport and storage solutions available to industrial companies that emit large quantities of CO_2";
- the sub-heading "Developing digital tools to improve cyber security". Although cybersecurity is an area of prime importance, CRE considers at this stage that the projects presented do not fall within the scope of R&D or do not appear to be intended to be carried out by Teréga itself without consultation with all the network operators;
- half of the "Intelligent energy system" item, which includes programmes outside the regulated remit of the TSOs (optimisation of renewable gas production, power-to-gas);
- the reversal of expenditure incurred in ATRT7 on the "health and safety at work" item. The explanations provided do not make it possible to explain the sharp increase in this item, whose budget was multiplied by five in the tariff application;
- expenditure not allocated to a specific item or project at this stage.

As a result, CRE is considering an R&D expenditure trajectory of €5.9 million over the ATRT8 period, i.e. an average of €1.6 million/year, compared with actual expenditure of €6.8 million in ATRT7.

Current M€	2022 actual	2024	2025	2026	2027

[16] Staff costs are included in the scope of net costs analysed by the auditor. Before the tariff deliberation, CRE will ensure that the adjustments made to this perimeter are consistent with the principles presented here.

Teréga's requested trajectory	1.2	6.6	8.6	6.6	6.5
CRE's preliminary trajectory		1.6	1.7	1.2	1.3
Impact on Teréga's demand		-5.0	-6.9	-5.3	-5.2

<u>Expenses related to congestion management mechanisms</u>

The congestion observed on the TRF (Trading Region France) during the winter of 2022/2023 led to a sharp increase in congestion absorption costs for TSOs. These are linked to the activation of the locational spread, with €54.6 million spent during the winter of 2022/2023.

The cost trajectory proposed by Teréga in its tariff application is high, and assumes higher costs than in the winter of 2022/2023 until 2027.

CRE's preliminary analysis

CRE notes that Teréga's forecast costs for the period 2024-2027 are not consistent with GRTgaz's assumptions on congestion volumes, as presented in the CRE's public consultation on the methods for managing South-North congestion on the gas transmission networks[17] in June 2023 (i.e. around 3.5 TWh/year on average over the period). CRE has also opted for a purchase price that is consistent with the price spreads between the French market and the Dutch market, a possible alternative for absorbing congestion.

CRE's preliminary trajectory results in a downward adjustment of Teréga's demand of - €27.2 M over the ATRT8 period.

Current M€	2022 actual	2024	2025	2026	2027
Teréga's requested trajectory	4.1	7.6	7.6	7.6	7.6
CRE's preliminary trajectory		1.1	0.9	0.8	0.6
Impact on Teréga's demand		-6.6	-6.7	-6.9	-7.0

<u>Expenses related to the interruptibility mechanism</u>

The guaranteed interruptibility mechanism was revised in 2022 to strengthen national security of gas supply for the winter of 2022/2023. In the end, this did not generate any costs for operators.

In its tariff request, Teréga introduces charges linked to the implementation of the mechanism (€12.6 million over the ATRT8 period), anticipating a revision of the mechanism.

CRE's preliminary analysis

In the absence of any information on possible changes to the mechanism and the form they might take, CRE is considering at this stage setting the corresponding trajectory at 0 for the ATRT8 period, as is the case for GRTgaz. This trajectory may change between now and the end of the year if the assumptions concerning the architecture of the mechanism and the anticipated costs for TSOs change. CRE also points out that it plans to cover this item in the CRCP.

Current M€	2022 actual	2024	2025	2026	2027
Teréga's requested trajectory	0	3.1	3.1	3.2	3.2
CRE's preliminary trajectory		0	0	0	0
Impact on Teréga's demand		-3.1	-3.1	-3.2	-3.2

- **Summary of preliminary analysis**

[17] see appendix 3 of Public consultation no. 2023-05 of 15 June 2023 on mechanisms for managing south to north congestions on the gas transmission networks

Teréga's request would lead to a 39% increase in non-energy operating costs in 2024 to be covered by the ATRT8 tariff, compared with the level of costs recorded in 2022.

At this stage of its analyses, CRE considers that the TSO's request is not justified and is therefore too high.

The conclusions of the audit report gave rise to an exchange of views with Teréga in July 2023. Teréga was able to comment on the results of the consultant's work, and questioned some of the adjustments identified by the consultant in the course of this discussion.

The level finally adopted by CRE will depend on the results of the analyses currently being carried out on the adjustments recommended by the auditor, and on any other adjustments envisaged by CRE.

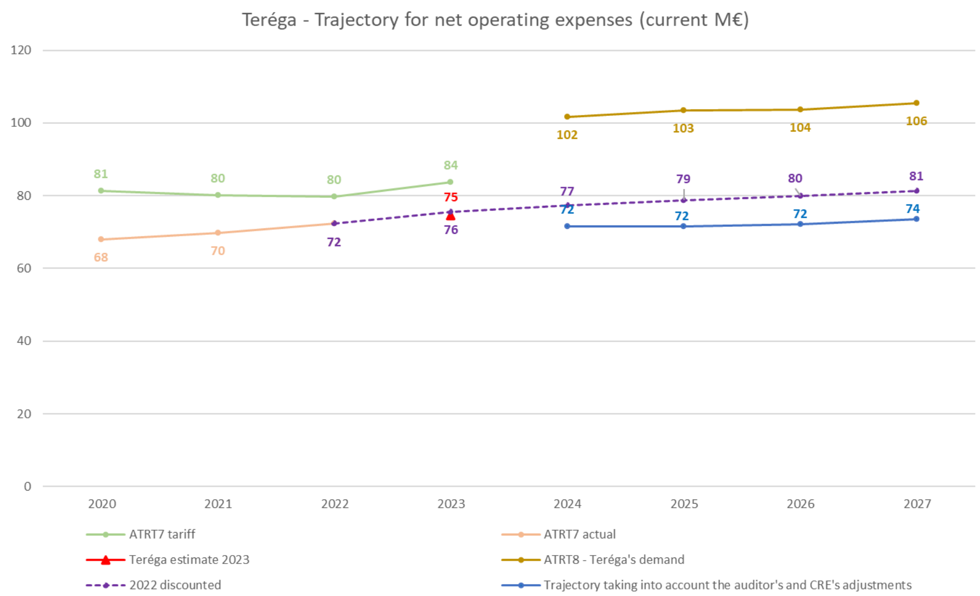
At this stage, CRE considers that the level of the operators' net operating costs could be between a "upper limit" corresponding to Teréga's request, and a "lower limit" established on the basis of all the conclusions of the external audit of the TSO's net operating costs and the adjustments considered by CRE and presented above.

For Teréga, the lower limit varies between €71.6 million in 2024 and €73.5 million in 2027, i.e. an average of €72.2 million over the period, and the upper limit varies between €101.6 million in 2024 and €105.5 million in 2027, i.e. an average of €103.5 million over the period.

These average levels are still higher than the €72.3m recorded in 2022:

- upper limit: growth between 2022 and 2024 of +41% (+39% excluding energy) and an average annual growth rate between 2024 and 2027 of +1%.
- lower limit: growth between 2022 and 2024 of -1% (-6% excluding energy) and an average annual growth rate between 2024 and 2027 of +1%.

The possible trajectories for levels of net operating expenses are as follows:



Q35 :	Do you agree with CRE's orientations on the R&D themes to be included in TSOs' costs trajectories?

4.4 Weighted average cost of capital

4.4.1 Operators' demand

4.4.1.1 GRTgaz

GRTgaz's request has been drawn up using a weighted average cost of capital (WACC) that is higher than that of the current ATRT7 tariff, i.e. 4.65% (real, before tax). This request is based on the conclusions of a study commissioned by the regulated natural gas infrastructures operators of the Engie group from an external consultant.

In its tariff demand, GRTgaz also uses the rate of 2.8% (nominal, before tax) for AuC remuneration.

4.4.1.2 Teréga

Teréga's request was based on a WACC of 4.70% (real, before tax), which is higher than the current ATRT7 tariff. This request is based on the conclusions of a study commissioned by Teréga from an external consultant.

In its tariff demand, Teréga uses a rate of 2.9% for AuC remuneration.

4.4.2 Summary of the results of CRE's external audit

As part of the work to prepare the ATRT8 tariff, CRE is re-examining the assumptions and parameters used to calculate the operators' remuneration rate. To this end, it has asked Compass Lexecon to carry out an audit and analysis of the remuneration requests from the two TSOs, the storage operators and GRDF, and the conclusions of their advisers. The consultant's report is published at the same time as this public consultation on the CRE website.

The work carried out by the auditor took place between May and July 2023. The consultant's report is published at the same time as this public consultation. After auditing the operators' requests, the auditor proposes several WACC ranges depending on the assets to which they apply. For historical assets, the auditor proposes a nominal pre-tax WACC range of between 3.72% and 4.14%, or an actual pre-tax WACC range of between 2.51% and 2.93%. For new assets, the auditor proposes a nominal pre-tax WACC range of between 5.69% and 6.21%, giving an actual pre-tax WACC range of between 2.74% and 4.23%.

4.4.3 WACC range envisaged by CRE

For the ATRT8 tariff, CRE does not intend to retain the operators' WACC requests (4.65% and 4.70%, real before tax, requested by GRTgaz and Teréga respectively). At this stage, CRE considers that these requests give too great a weighting to the recent changes in interest rates on the markets since the period when the ATRT7 tariff was set, and that they include a number of new elements whose justifications cannot be accepted at this stage.

Nor does CRE intend to adopt the limits of the range recommended by the auditor appointed to audit operators' requests. This range would represent too sharp a departure from the methods and parameters used to date by CRE, particularly as regards the level of asset beta.

To formulate its range, CRE based itself on the consultant's approach, in which it took account of certain possible changes in parameters, sometimes over wider ranges than the consultant, such as, for example, taking account of longer maturities for the risk-free rate or a higher level of asset beta.

Overall, CRE considers that:

- the long-term rate according to the method used for the ATRT7 and previous tariffs, based on the analysis of long-term parameters and intended to reflect the financing conditions for historical assets, could be between 2.7% and 3.9% (real, before tax);
- the short-term rate, based on an analysis of shorter-term parameters and designed to reflect the financing conditions of new assets, could range from 3.6% to 5.2% (actual, before tax).

These rates can be applied to old and new assets respectively, or combined into a weighted rate. Using an indicative weighting assumption of 80% historical assets and 20% new assets over the tariff period, the **average WACC would therefore be between 2.9% and 4.2% (actual, before tax).**

In nominal pre-tax terms, the ranges would be as follows: [3.9% - 5.1%] for the historical rate, [6.1% - 7.2%] for the short-term rate and [4.4% - 5.5%] for the weighted rate.

4.5 Investments and normative capital charges

4.5.1 GRTgaz

4.5.1.1 Investments trajectory

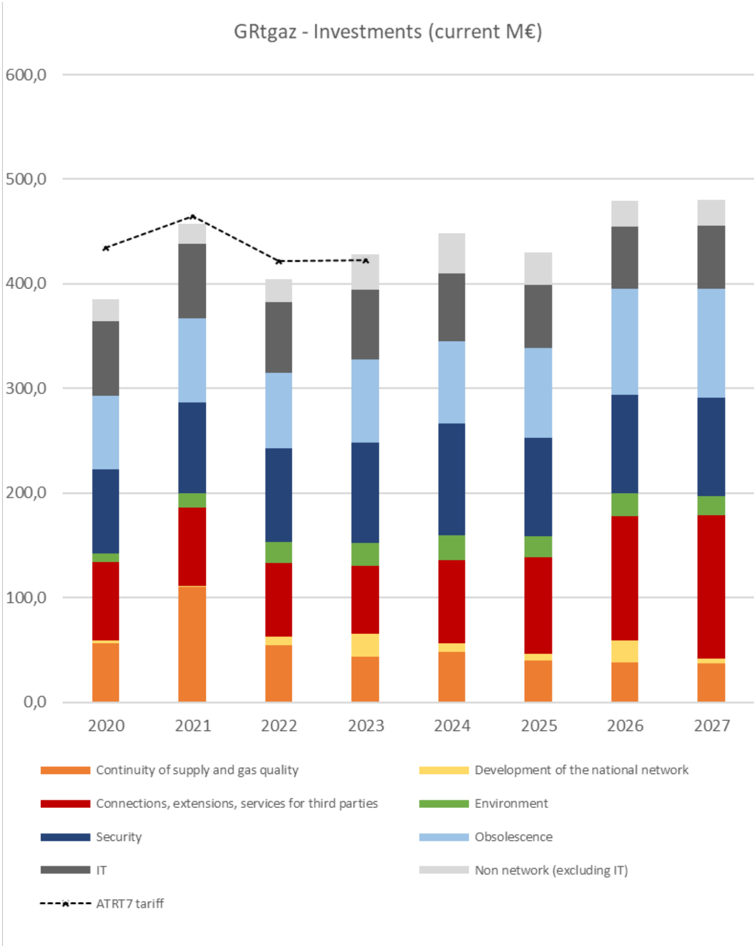
GRTgaz's forecast for investment over the ATRT8 period is slightly increasing, with average expenditure of around €460 million per year over this period, compared with €419 million per year over the ATRT7 period. This increase is mainly due to higher investment in connections, extensions and services for third parties.

GRTgaz forecasts the following investment expenditure over the next tariff period:

Current M€	2024	2025	2026	2027	Yearly average ATRT8	Yearly average ATRT7*
Continuity of supply and gas quality	47.9	39.5	38.2	37.4	40.7	66.2

Development of the national network	8.9	7.1	20.8	4.0	10.2	8.3
Connections, extensions, services for third parties	79.3	91.6	119.2	136.9	106.8	71.3
Environment	23.5	20.7	21.2	19.1	21.1	15.9
Security	107.2	93.9	94.1	94.0	97.3	88.4
Obsolescence	78.2	86.0	101.4	104.2	92.5	75.6
IT	65.0	60.0	60.0	60.0	61.3	69.0
Non network (excluding IT)	37.8	31.2	24.6	24.8	29.6	24.2
TOTAL	**447.9**	**430.1**	**479.5**	**480.4**	**459.5**	**418.9**

* Average of investment programmes completed in 2020, 2021, 2022 and estimated 2023



In particular, GRTgaz plans:

- an increase in expenditure on connections and services for third parties (+€142 million over the period, or +50%), mainly due to an acceleration in the number of backhauls carried out (+€112 million over the period);
- an increase in obsolescence-related expenditure (+€67 million over the period, or +22%). This includes the €78 million project to renovate the La Bégude compressor station from 2025, as well as €43 million in provisions over the period, corresponding to projects that have not yet been identified;
- an increase in expenditure on safety (+€36 million over the period, i.e. +10%), the environment (+€21 million over the period, i.e. +33%, due to programmes to reduce methane emissions and deal with the presence of asbestos on its facilities), and vehicles and property (+€22 million over the period, i.e. +22%, in particular in order to take account of obligations relating to the tertiary sector decree);
- a drop in expenditure on continuity of gas supply and quality (-€102 million, or -38%), due to the end of major projects, such as the reinforcement of the network in Brittany;

- a decrease in expenditure on the information system (-€31 million, or -11%), with the end of certain major projects to overhaul the business IT, but an increase in expenditure on cybersecurity (+€40 million over the period).

4.5.1.2 Capital costs trajectory

The investment forecasts presented above, combined with a weighted average cost of capital of 4.65 % requested by GRTgaz, result in the following normative capital charge request in GRTgaz's tariff resquest:

Current M€	2024	2025	2026	2027	Yearly average ATRT8
GRTgaz RAB trajectory	9 411	9 456	9 376	9 320	**9 391**
Request for GRTgaz's NCE (WACC of 4.65 %)	1 125	1 125	1 107	1 101	**1 115**

4.5.1.3 CRE's preliminary analysis

<u>Investment expenditures</u>

CRE notes that the trajectory proposed by GRTgaz is higher than in the previous period, mainly because of the increase in expenditure on biomethane, which is 50% higher than in the ATRT7. Apart from this item, the rest of the expenditure follows a stable trajectory and corresponds to an investment cycle without any major reinforcement or development of the network.

In accordance with the system of incentive regulation of investment expenditure (see paragraph 3.3.2), certain projects may be subject to audits to define a target budget. This is particularly the case for at least three projects (phase 2 of the Telester programme, renewal of the La Bégude compressor station, the Gournay-Cuvilly link), for which GRTgaz has estimated budgets over €20 million and which are eligible for the incentive regulation system for major projects.

Expenditure on non-network projects is stable compared with the previous period, averaging €91 million a year, or 20% of total expenditure over the period. They are eligible for incentive regulation of non-infrastructure investments (see paragraph 3.3.2.3).

At this stage, CRE does not plan to change GRTgaz's planned investment trajectory. However, it considers that in the context of the structural decline in gas consumption and the risk of an increase in the associated unit cost of transmission, the operators' investment expenditure must be kept under control as far as possible. CRE will ensure that these expenses are kept under control during the annual approval of TSO investments, as provided for in articles L. 134-3 and L. 431-6-II of the Energy Code.

<u>Capital costs</u>

<u>Stranded cost trajectory</u>

The stranded costs trajectory requested by GRTgaz consists of a base corresponding to the average achieved over the period 2020-2022 (i.e. €4.6 million/year), to which GRTgaz adds an amount of €1 million/year corresponding to asset retirements considered "highly probable" by the operator.

CRE notes that the actual figures for 2020-2022 already include asset outflows of the type included in GRTgaz's additional trajectory, at a comparable annual level. At this stage, therefore, it plans to set the ATRT8 trajectory at the level of the ATRT7 actual for 2020-2022, which corresponds to a downward adjustment of €3.9 million over the period.

Current M€	2024	2025	2026	2027
Path requested by GRTgaz	5.6	5.6	5.6	5.6
CRE's preliminary trajectory	4.6	4.6	4.6	4.6
Impact on GRTgaz's demand	-1.0	-1.0	-1.0	-1.0

<u>Normative capital expenses trajectory</u>

As indicated in section 4.4.3, CRE is considering at this stage using a WACC value that could be between 2.9% (actual, before tax) and 4.2% (actual, before tax) to remunerate the regulated asset base of the two operators, i.e. 4.4% (nominal, before tax) and 5.5% (nominal, before tax).

Finally, as presented in section 3.7, CRE is considering adapting the tariff regulation framework in order to limit the risk of an excessive increase in the unit cost of transmission for future network users, by ending the indexation of the RAB to inflation, or by implementing a degressive depreciation of the operators' assets. All other things being equal, these adjustments to the tariff framework would lead to an increase in operators' capital costs when they are implemented.

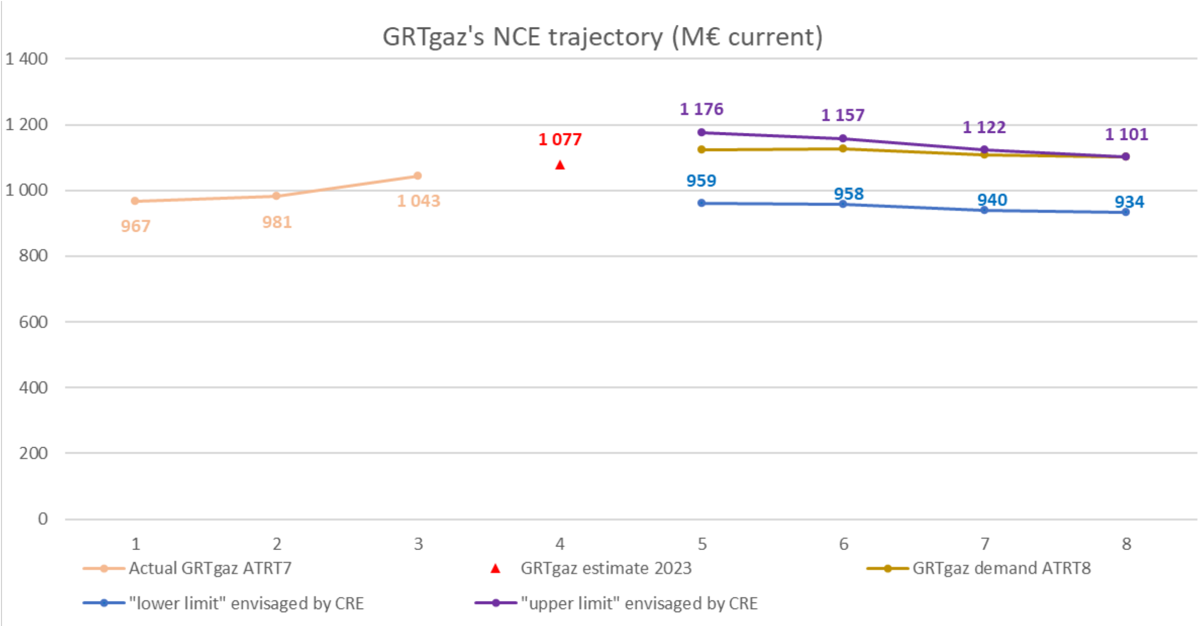
Consequently, CRE considers at this stage that the level of operators' normative capital charges could fall between:

- a "lower limit", incorporating a return on the asset base at the lowest WACC envisaged by CRE (i.e. 2.9% real, before tax);
- an "upper limit", taking into account one of the planned changes to the tariff framework (the end of indexation of the RAB to inflation, by way of illustration) and incorporating a return on the asset base at the highest WACC envisaged by the CRE (i.e. 5.5% nominal, before tax).

For GRTgaz, these trajectories imply the following changes:

- lower limit: change from 2022 to 2024 of -8% and an average annual growth rate from 2024 to 2027 of -1%.
- upper limit: growth from 2022 to 2024 of +13% and an average annual growth rate from 2024 to 2027 of -2%.

The possible trajectories for levels of normative capital charges are as follows:



The corresponding RAB trajectories are shown below:

Current M€	2024	2025	2026	2027
RAB GRTgaz – upper limit	9 411	9 456	9 377	9 324
RAB GRTgaz – lower limit	9 190	9 080	8 877	8 707

4.5.2 Teréga

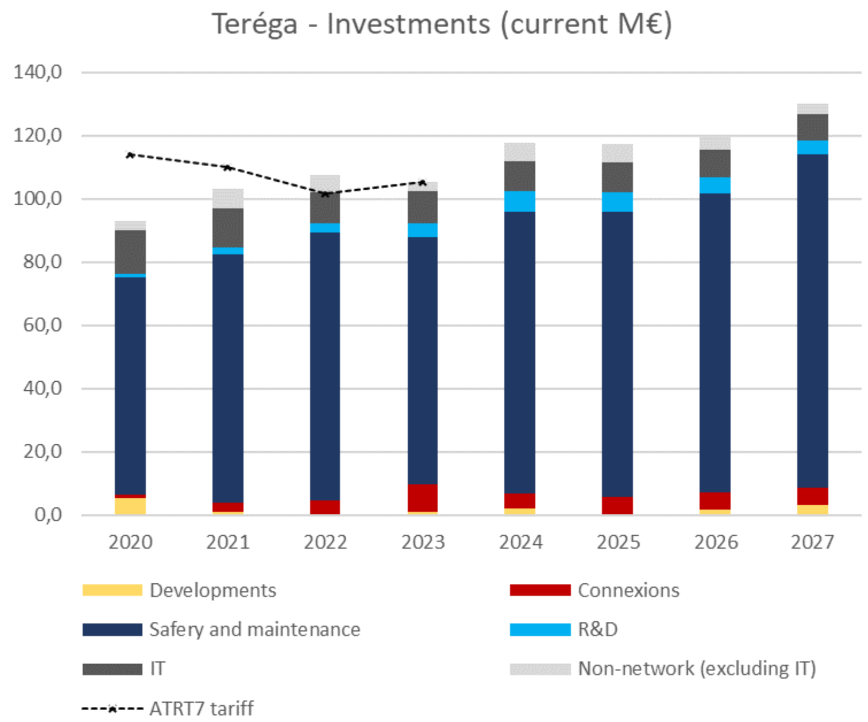
4.5.2.1 Investments trajectory

The trajectory of Teréga's investment expenditure over the ATRT8 period is up, with average expenditure of €121 million per year over this period, compared with around €102 million per year during the ATRT7 period. This increase in expenditure is linked in particular to the "safety and maintenance" item, which rose by €17.3 million over the period.

Teréga plans the following investment expenditure over the next tariff period:

Current M€	2024	2025	2026	2027	Yearly average ATRT8	Yearly average ATRT7*
Developments	2.1	0.1	1.7	3.2	1.7	1.8
Connexions	4.7	5.5	5.3	5.5	5.2	4.4
Safety and maintenance	88.9	90.1	94.8	105.3	94.8	77.5
R&D	6.6	6.5	4.9	4.3	5.5	2.6
IT	9.7	9.2	8.8	8.5	9.1	11.6
Non-network (excluding IT)	5.5	5.8	4.3	3.2	4.7	4.2
TOTAL	**117.5**	**117.2**	**119.7**	**130.0**	**121.1**	**102.1**

* Average of investment programmes completed in 2020, 2021, 2022 and estimated 2023



In particular, Teréga plans:

- an increase in expenditure on safety and maintenance (+€69 million over the period, or +22%). This mainly concerns pipelines (+€95 million over the period, or +42%), and is the result of Teréga's planned programme to renew the regional network's pipelines, with around ten projects worth more than €20 million already under study or due to be launched during the next tariff period;
- higher R&D expenditure (+€12 million over the period, or +113%);
- a drop in IT-related expenditure (-€10 million, or -22%), linked to Teréga's decision to prioritise OPEX expenditure on IT.

4.5.2.2 Capital costs trajectory

The investment forecasts presented above, combined with a weighted average cost of capital of 4.70% requested by Teréga, result in the following normative capital costs request in Teréga's tariff request:

Current M€	2024	2025	2026	2027	Yearly average ATRT8
Teréga's RAB trajectory	1 869	1 908	1 947	2 013	**1 934**
Teréga's request for a NCE (WACC of 4.70%)	196	197	198	204	**198**

4.5.2.3 CRE's preliminary analysis

Investment expenditure

CRE notes that the trajectory proposed by Teréga is 19% higher than in the previous period, mainly due to the increase in expenditure linked to the renewal of pipelines on the regional network. CRE questions the compatibility of these investments with a future decrease in gas consumption, which could fuel the risk of an increase in unit transmission costs already identified.

In accordance with the system of incentive regulation of investment expenditure (see paragraph 3.3.2), certain projects may be subject to audits to define a target budget. This is the case for at least six pipeline renewal projects on the regional network.

CRE plans to exclude certain R&D investments, which analysis at this stage suggests are not essential to the performance of the TSO's missions, in line with the planned adjustments to operating costs presented in section 4.3.3.2. This leads to a downward adjustment in investments of -€12.9m over the period.

Apart from R&D expenditure, CRE does not at this stage plan to make any changes to the investment trajectory requested by Teréga. However, CRE would point out that in the context of the structural decline in gas consumption and the risk of an increase in the associated unit cost of transmission, operators' investment expenditure must be kept under control as far as possible. CRE will ensure that this investment expenditure is kept under control during the annual approval of TSO investments, as provided for in articles L. 134-3 and L. 431-6-II of the Energy Code.

The investment trajectory resulting from the adjustments envisaged by CRE is as follows:

Current M€	2024	2025	2026	2027	Yearly average ATRT8	Yeary average ATRT7*
Developments	2.1	0.1	1.7	3.2	1.7	1.8
Connexions	4.7	5.5	5.3	5.5	5.2	4.4
Safety and maintenance	88.9	90.1	94.8	105.3	94.8	77.5
R&D	3.2	1.4	2.7	2.0	2.3	2.6
IT	9.7	9.2	8.8	8.5	9.1	11.6
Non-network (excluding IT)	5.5	5.8	4.3	3.2	4.7	4.2
TOTAL	**114.2**	**112.1**	**117.5**	**127.7**	**117.9**	**102.1**

* Average of investment programmes completed in 2020, 2021, 2022 and estimated 2023

Normative capital charges

Stranded costs trajectory

Teréga's stranded costs over the period 2020-2022 are in line with the ATRT7 trajectory. Teréga proposes to maintain the same level for the ATR8 trajectory (i.e. approximately €0.3 million/year). At this stage, CRE does not plan to make any adjustments to this trajectory.

Normative capital expenses trajectory

As indicated in section 4.4.3, CRE is considering at this stage using a WACC value that could be between 2.9% (actual, before tax) and 4.2% (actual, before tax) to remunerate the regulated asset base of the two operators, i.e. 4.4% (nominal, before tax) and 5.5% (nominal, before tax).

Finally, as presented in section 3.7, CRE is considering adapting the tariff regulation framework in order to limit the risk of an excessive increase in the unit cost of transmission for future network users, by ending the indexation of the RAB to inflation, or by implementing a degressive depreciation of the operators' assets. All other things being equal, these adjustments to the tariff framework would lead to an increase in operators' capital costs when they are implemented.

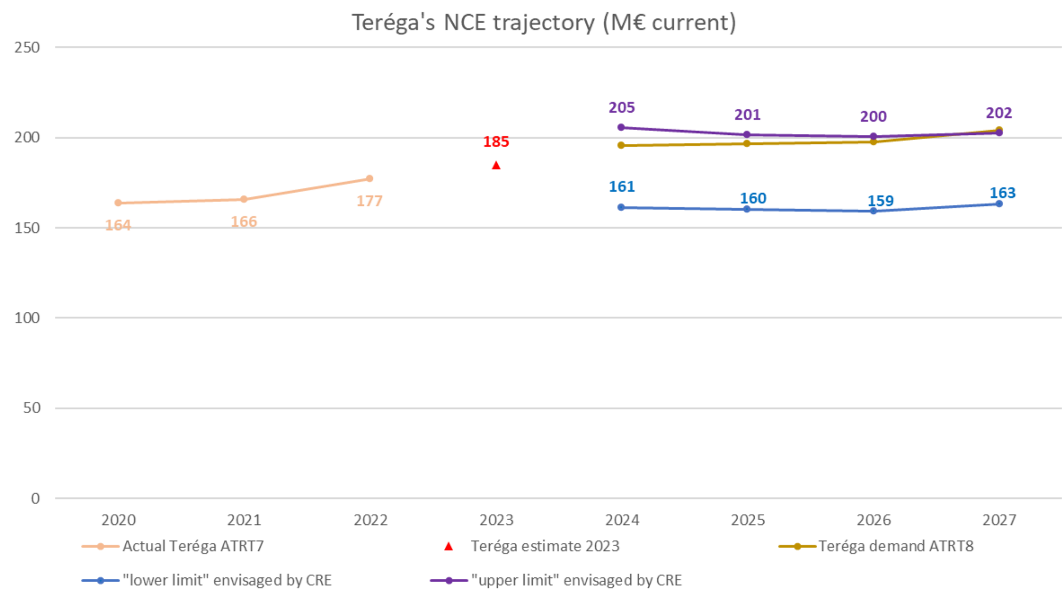
Consequently, CRE considers at this stage that the level of operators' normative capital charges could fall between:

- a "lower limit", incorporating a return on the asset base at the lowest WACC envisaged by CRE (i.e. 2.9% real, before tax) ;
- an "upper limit", taking into account one of the changes in the tariff framework envisaged (the end of indexation of the RAB to inflation, by way of illustration) and incorporating a return on the asset base at the highest WACC envisaged by the CRE (i.e. 5.5% nominal, before tax).

For Teréga, these trajectories imply the following changes:

- lower limit: change 2022-2024 of -9% and a 2024-2027 average annual growth rate of +0.4
- upper limit: 2022-2024 growth of +16% and a 2024-2027 average annual growth rate of -0.5%.

The possible trajectories for levels of normative capital charges are as follows:



The corresponding RAB trajectories are shown below:

Current M€	2024	2025	2026	2027
RAB Teréga – upper limit	1 869	1 909	1 949	2 018
RAB Teréga – lower limit	1 826	1 833	1 846	1 888

4.6 CRCP as at 31 December 2023

The overall CRCP balance is calculated before the final closing of the annual accounts. It is therefore equal to the amount to be paid into or deducted from the CRCP (i) in respect of the previous year, on the basis of the best estimate of annual costs and revenue (known as the estimated CRCP), and (ii) in respect of the previous year, by comparing actual costs and revenue with the estimate made one year earlier (known as the definitive CRCP), plus, where applicable, the balance of the CRCP balance not reconciled in respect of previous years.

The amount to be paid or deducted from the CRCP is calculated by CRE, for each past year, according to the difference between the actual or estimated figures for each item concerned and the reference amounts defined in appendix 8 of the ATRT7 decision. The proportion of this difference paid to the CRCP is set out in the ATRT7 decision.

4.6.1 GRTgaz

In its demand concerning the 2024-2027 ATRT8 period, GRTgaz estimated the CRCP balance at December 31, 2023 at -€94.1 million to be returned to transmission system users[18]. This balance is the sum of the following items:

- the discounted balance of the previous CRCP (i.e. -€126.7 million);

[18] By convention, as far as the CRCP is concerned, a "-" sign corresponds to an amount to be returned to users, and a "+" sign to an amount to be returned to the operator.

- the discounted difference between the estimated balance for 2022 and the final CRCP for 2022 (i.e. +€64.8 million);
- the estimated balance for 2023 (i.e. -€32.2 million).

The CRCP at 31 December 2023 estimated by CRE amounts at this stage to -€133.7 million, to be returned to network users. This balance is the sum of the following elements

- the discounted balance of the previous CRCP (i.e. -€126.7million);
- the discounted difference between the estimated balance for 2022 and the definitive CRCP balance for 2022 (i.e. +€67.0 million), which is mainly due to lower-than-estimated receipts from sales of capacity (including surpluses linked to auction receipts) (€49.9 million);
- the estimated CRCP for 2023 (-€74.0 million), mainly due to :
    - higher-than-estimated income from sales of capacity (including surplus revenue from capacity auctions) (€367.6 million);
    - higher-than-expected costs for energy (+€172.1 million), capital costs (+€67.6 million), conversion of H-gas to L-gas (+€32.8 million) and congestion management (+€20 million).

The difference between GRTgaz's request and the level adopted at this stage by the CRE (-€39.6 million) is mainly due to a correction concerning the calculation of revenue from sales of capacity at Obergailbach in 2023 (-€17 million) and the use of different assumptions from those of GRTgaz concerning the costs associated with congestion management for 2023 (-€24.1 million).

GRTgaz	Amounts updated for 2022	Amounts updated for 2023
Transmission revenue covered at 100%	+ 54.3	- 281.0
Transmission revenue covered at 80%	- 4.3	- 86.6
Normative capital charges	+ 3.3	+ 67.6
Energy charges	+ 4.3	+ 172.1
Interoperators transit contract	0	- 1.5
OPEX variance due to inflation	- 0.1	+ 3.3
Quality of service	+ 0.1	+ 1.5
H-B conversion service costs	- 0.1	+ 32.8
Income from services provided to third parties in connection with major development projects	+ 5.5	+ 8.3
Congestion management costs	+ 0.3	+ 20.0
Connection of biomethane units	+ 1.0	- 3.8
Inter-operator transfer	0	+ 1.4
Cost of consumables	- 1.3	+ 2.9
Reversement DSO-> GRTgaz (Opex associated with backhauls)	+ 0.2	- 0.3
Contracts with adjacent operators	+ 3.8	- 10.9
Total	**+ 67.0**	**- 74.0**
Previous CRCP balance updated	**- 126.7**	
CRCP balance at 31 December 2023	**- 133.7**	

This amount of CRCP is preliminary and may change in CRE's final decision.

4.6.2 Teréga

In its demand concerning the 2024-2027 ATRT8 period, Teréga estimated the CRCP balance at 31 December 2023 at €0.8 million to be returned to the operator. This balance is the sum of the following elements:

- the discounted difference between the estimated balance for 2022 and the final CRCP for 2022 (i.e. +€0.9 million);

- the estimated CRCP for 2023 (i.e. -€0.1 million).

The CRCP at 31 December 2023 estimated by CRE amounts at this stage to €1.6 million, to be returned to network users. This balance is the sum of the following elements

- the updated difference between the estimated balance for 2022 and the definitive CRCP balance for 2022 (i.e. +€0.9 million), which is mainly due to lower-than-estimated receipts from sales of capacity (including surpluses linked to auction receipts) (+€0.5 million);
- the estimated CRCP for 2023 (€2.5 million), which is mainly due to :
  - the restatement of Teréga's operating expenses to exclude inspection and rehabilitation expenses, which are now included in the TSO's capital expenses (-€7.8 million);
  - lower-than-expected charges relating to the inter-operators transfer to GRTgaz (-€6.7 million);
  - net expenses related to contracts with adjacent operators lower than forecast (-€2.3 million).
  - higher-than-expected charges for energy (+€1.1 million), capital costs (+€9.4 million) and congestion management (+€2.7 million).

The difference between Teréga's request and the level adopted at this stage by CRE (€2.4 million) is mainly due to the fact that Teréga's assumptions regarding congestion management costs for 2023 differ (€1.0 million) and to the fact that Teréga's request to cover €1.3 million in stranded costs was not taken into account, as these elements were not sufficiently justified by the operator at this stage.

Teréga– CRCP as of 31 December 2023

Teréga	Amounts updated for 2022	Amounts updated for 2023
Transmission revenue covered at 100%	+ 1.0	- 9.2
Transmission revenue covered at 80%	- 0.5	+ 11.5
Normative capital charges	+ 0.1	+ 9.4
Energy charges	+ 0.1	+ 1.1
Interoperators transit contract	0	+ 1.4
OPEX variance due to inflation	0	- 7.5
of which restated to reflect the classification of inspection and rehabilitation expenditure		- 7.8
Quality of service	+ 0.1	+ 0.7
Income from services provided to third parties in connection with major development projects	+ 0.2	- 1.4
Congestion management costs	+ 0.0	+ 2.7
Connection of biomethane units	+ 0.1	- 2.4
Connection of biomethane production units	0	+ 0.1
Inter-operator transfer	- 0.2	- 6.7
Contracts with adjacent operators	0	- 2.3
Total	**+ 0.9**	**- 2.5**
Previous CRCP balance updated	**0**	
CRCP balance at 31 December 2023	**- 1.6**	

This amount of CRCP is preliminary and may change in CRE's final decision.

4.7 Costs to be covered

4.7.1 Operators' demand

4.7.1.1 GRTgaz

GRTgaz's request results in an increase in costs to be covered of +32.1% in 2024 compared with 2023, and an average annual change of -1.9% over the ATRT8 period.

Current M€	2023 Allowed revenue update	2024	2025	2026	2027
NOE		1 176.2	1 079.6	1 080.9	1 074.8
NCE		1 124.8	1 125.3	1 106.9	1 101.2
Reconciliation of ATRT7 CRCP		-22.0	-22.0	-22.0	-22.0
Costs to be covered	1 724.6	2 279.1	2 183.0	2 165.8	2 153.9
Annual change	-	+ 32.1 %	-4.2 %	-0.8 %	-0.5 %

4.7.1.2 Teréga

Teréga's request results in an increase in expenses to be covered of +10.5% in 2024 compared with 2023, and an average annual increase of +1.3% over the ATRT8 period.

Current M€	2023 Allowed revenue update	2024	2025	2026	2027
NOE		101.6	103.4	103.6	105.5
NCE		195.6	196.7	197.8	203.8
Reconciliation of ATRT7 CRCP		0.2	0.2	0.2	0.2
Costs to be covered	269.2	297.4	300.3	301.7	309.5
Annual change	-	10.5 %	1.0 %	0.5 %	2.6 %

Q36 : Do you have any comments on the level of costs to be covered requested by GRTgaz and Teréga?

4.7.2 Illustrative scenario for the tariff grid

At this stage, CRE has the analytical elements provided in the audit reports on the TSOs' operating costs and the rate of return on their capital.

In the following tables, CRE presents an illustrative allowed revenue for each TSO, using the central values of the upper and lower limits it presented earlier for net operating costs and normative capital costs, and a reconciliation of the CRCP estimated at the end of the ATRT7 smoothed over the ATRT8 period. The difference in the annual change in the two operators' expenses to be covered in 2024 is mainly due to a larger amount of "system" expenses for GRTgaz, covered by the CRCP.

4.7.2.1 GRTgaz

Current M€	2023 Updated allowed revenue	2024	2025	2026	2027
NOE (central value)		1 083.4	984.2	961.5	939.7
NCE (central value)		1 067.9	1 057.1	1 031.0	1 017.3
Reconciliation of ATRT7 CRCP		-34.9	-34.9	-34.9	-34.9
Illustrative costs to be covered	1 724.6	2 116.4	2 006.4	1 957.6	1 922.1
Annual change	-	22.7 %	-5.2 %	-2.4 %	-1.8 %

4.7.2.2 Teréga

Current M€	2023 Updated allowed revenue	2024	2025	2026	2027
NOE (central value)		86.6	87.5	87.9	89.5
NCE (central value)		183.3	180.8	179.8	182.8
Reconciliation of ATRT7 CRCP		-0.4	-0.4	-0.4	-0.4
Illustrative costs to be covered	269.2	269.5	267.9	267.3	271.9
Annual change	-	0.1 %	-0.6 %	-0.2 %	1.7 %

Q37 : Are you in favour of the orientations envisaged by CRE concerning the level of costs to be covered for the ATRT8 period for GRTgaz and Teréga?

4.8 Forecast capacity subscriptions

4.8.1 Operators' demand

4.8.1.1 GRTgaz

GRTgaz submits a subscription trajectory based on the following forecasts:

- a gradual and significant drop in long-term subscriptions at the IPs, both on the entry side (Dunkirk, Obergailbach and Virtualys) and on the exit side (Oltingue);
- high and stable entry subscriptions from LNG terminals, in line with the strong increase in LNG flows;
- the gradual reduction in subscriptions at the exit point of the main network and on the regional network as a result of a reduction in peak consumption (under the dual effect of efforts to reduce energy consumption and the updating of the climatic reference used to calculate peak consumption);
- fully subscribed storage capacity.

% change in capacity subscriptions per year	2024	2025	2026	2027	average annual evolution
National network	-2.2 %	-5.1 %	-7.2 %	-13.7 %	-7.1 %
Regional network	-1.3 %	-4.0 %	-5.0 %	-4.1 %	-3.6 %

4.8.1.2 Teréga

Teréga submits a subscription trajectory based on the following forecasts:

- assumptions for flows that are structurally oriented from south to north;
- a sharp increase in entries at Pirineos over the entire period;
- the gradual reduction in subscriptions at the exit point of the main network and on the regional network, induced by a reduction in peak consumption (under the dual effect of efforts to reduce energy consumption and the updating of the climatic reference used to calculate peak consumption);
- storage capacity fully subscribed.

% change in capacity subscriptions per year	2024	2025	2026	2027	average annual evolution
National network	-8.3 %	-5.0 %	-9.5 %	-33.7 %	-15.0 %
Regional network	-2.3 %	-3.2 %	-3.3 %	-2.9 %	-2.9 %

4.8.2 CRE's preliminary analysis

CRE is in line with most of the forecasts used by the TSOs, but considers that certain assumptions are conservative. CRE is therefore considering a number of adjustments:

Firstly, CRE considers that the assumptions for GRTgaz's entry subscriptions on the transmission network are not sufficient to balance the physical TRF balance, taking into account realistic capacity utilisation rates.

CRE therefore plans to increase the TSOs' entry capacity assumptions by around 125 GWh/d/year (+5% compared with the TSOs' assumptions).

Secondly, CRE considers that the reduction in downstream subscriptions (exiting the main network, on the regional network and at delivery points to consumers) forecast by the TSOs is too great. As a reminder, downstream subscriptions are calculated on a normative basis by operators and correspond, as a first approximation, to peak consumption at 2% risk.

CRE is considering raising the assumptions for subscriptions exiting the main network from the 3,748 GWh/d/year proposed by the TSOs on average over the ATRT8 period to 3,900 GWh/d/year. This assumption makes it possible to restore consistency with the ADEME S3 scenario, used in the study on the future of gas infrastructures, and by the TSOs to construct their consumption assumptions.

The table below shows the forecast capacity subscriptions envisaged by CRE, on average over the ATRT8 period.

MWh/d/year	Subscribed entry capacity	Subscribed exit capacity
IP Virtualys	188 500	19 000
IP Taisnières B	[Confidential]	0
IP Dunkerque	550 000	0
IP Obergailbach	218 200	50 000
IP Oltingue	0	190 000
IP Pirineos	252 800	54 000
PITTM Dunkerque	370 000	
PITTM Fos	407 300	
PITTM Montoir	382 000	
PITTM Le Havre	110 000	

PITS Nord-Ouest	394 500	213 000
PITS Atlantique	634 500	320 000
PITS Sud-Est	644 500	110 000
PITS Nord B	66 500	42 000
PITS Nord Est	176 000	125 000
PITS Sud-Ouest	556 000	300 000
Exit to regional network		*3 900 000*

Q38 : Do you have any comments on the projected subscriptions envisaged by CRE for the period 2024-2027?

4.9 Smoothed trajectory of allowed revenue

To calculate the tariff change on 1 April 2023 and for each annual change, CRE plans to smooth the change in operators' forecast allowed revenue, as it has done in previous tariffs. This smoothing has no impact on the overall costs recovered by TSOs over the tariff period, but avoids major changes in opposite directions from one year to the next. Forecast subscriptions are also taken into account so as to have a constant tariff evolution over the four years of the tariff.

In implementing this smoothing, CRE will ensure, as far as possible, that the level of tariff terms for the ATRT8 period reflects the TSOs' costs and revenues.

The tables presented below are based on the illustrative tariff grids determined by the tariff structure and presented in section 5.

As indicated in sections 5.2.2.2.5 and 5.3.3, they take into account, at this stage, a simple smoothing of the tariff terms of the type Z = CPI + X + k, with X fixed at 0. In other words, an evolution of the "initial step" type followed by an annual evolution in line with inflation.

Lastly, the tariff grid resulting from the structure of the main network implies an imbalance in the distribution of subscription income between the two TSOs compared to their respective costs associated with the main network, of around €12 million/year over the tariff period, to Teréga's disadvantage: as indicated in section 3.2.2.4, CRE therefore plans to replace the transfer from Teréga to GRTgaz implemented when the zones were merged (and calculated on the basis of outgoing subscriptions to the Pirineos IP) with a transfer from GRTgaz to Teréga enabling each of the two operators to cover their respective costs associated with the main network. This payment is also included in the smoothed allowed revenue shown in the table below.

4.9.1 GRTgaz

Current M€	2023	2024	2025	2026	2027
Illustrative expenses to be covered	1 724.6	2 116.4	2 006.4	1 957.6	1 922.1
Inter-operator transfer ATRT8		12.4	12.4	12.4	12.4
Smoothing term ATRT8		-131.2	75.1	77.8	-16.5
Smoothed allowed revenue	1 724.6	1 997.5	2 093.9	2 047.8	1 918.0

4.9.2 Teréga

Current M€	2023	2024	2025	2026	2027

Illustrative expenses to be covered	269.2	269.5	267.9	267.3	271.9
Inter-operator transfer ATRT8		-12.4	-12.4	-12.4	-12.4
Smoothing term ATRT8		8.6	17.5	7.5	-35.6
Smoothed allowed revenue	269.2	265.7	273.0	262.5	223.9

5. STRUCTURE OF TARIFFS FOR THE USE OF THE NATURAL GAS TRANSMISSION NETWORK

5.1 Representation of the network and scope covered by the ATRT8 tariff

The transmission network is associated with a single market zone, the Trading Region France (TRF).

The transmission network comprises, on the one hand, the main network, and on the other hand, the regional network. Users of GRTgaz's and Teréga's networks make several uses of the gas transmission network: transit, which consists in having gas enter the networks to ship it to another country; and domestic transmission, which consists in shipping gas to be consumed in France. Users may also use underground natural gas storage.

Moreover, in the north of France, there is an "L gas" zone supplied in low calorific gas (called "L gas"), whose network is physically separated from the rest of the French transmission network.

The French natural gas transmission network in 2023

CRE defines the gas transmission tariffs to avoid any cross-subsidisation between the different categories of transmission network users, particularly between users accessing the network for transit and those supplying domestic consumption. It also ensures the absence of cross-subsidisation between the two network categories, main and regional, by guaranteeing that the income received at each network corresponds to the expenses generated by their use.

The structure of the ATRT8 tariff covers three categories: the main network, the regional network and the storage compensation.

- Main network

The main network is composed of network elements that connect the interconnection points with (i) adjacent transmission networks (ii) exits to the regional network, (iii) LNG terminals and (iv) storages. It covers more than 9,000 km. Flows are generally bi-directional.

The tariff structure of the main network is based on an entry/exit pricing principle per market place. Gas can be bought and/or sold directly in the market place or gas exchange point (PEG). In this case, the user pays the specific tariff charges at the PEG.

Users can bring gas into France by interconnections through pipes (network interconnection points, or IPs) or by LNG terminals (transmission/LNG terminal interface points, or PITTMs) and for this they pay entry charges at these points. These charges are identical regardless of the destination of the gas (transit, storage or domestic consumption).

The gas exits the main network at different points, based on its destination:

- to ship the gas to a neighbouring country, in particular for transit uses, users pay an exit charge at the IP;
- to supply national consumption, users pay a charge for exit to the regional network.

Underground natural gas storage facilities are located on the main network. Network users access those facilities by paying entry and exit charges at the transmission/storage interface points (PITS).

The tariff principles of the main network are described in section 5.2 of the public consultation.

- Regional network

The regional network is composed of network elements that enable gas to be shipped from the main network to end customers or distribution networks. It covers more than 28,000 km. Flows are generally unidirectional.

Supply of each delivery point requires the subscription, on the one hand, of transmission capacity, and on the other hand, of delivery capacity. There are three types of delivery points:

- transmission/distribution interface points (PITDs) which represent the interface between the transmission network and one or several exits to the distribution network;
- sites of industrial customers directly connected to the transmission network;
- interconnection points on the regional network (PIRRs) which enable delivery to foreign regional networks.

The tariff principles of the regional network are described in section 5.3 of the public consultation.

- Storage compensation

Introduced in the ATRT tariff in 2018, within the framework of the regulation of the conditions for accessing natural gas storage infrastructure, storage compensation corresponds to the difference between forecast allowed revenue of natural gas storage operators and the income they receive directly, mainly for auctioning storage capacity. It is collected by the TSOs, which return it to the storage operators. The principles for collecting compensation are presented in section 6 of the public consultation.

5.2 Main network tariff structure

5.2.1 Thematic consultation workshop

On 4 May 2023, CRE organised a workshop with gas market players on the changes on the main network tariff structure. The workshop was attended by 70 participants.

During the workshop, CRE presented the challenges of the next generation of tariffs in connection with the end of long-term contracts, the reorganisation of gas demand and supply patterns in Europe and the decline in gas consumption. CRE then detailed three indicative scenarios for the structure of the main gas transmission network (presented below), and presented the associated consequences in terms of tariff changes.

- Scenario "A", based on the ATRT7 structure, for comparison purposes;
- Scenario “B”, taking into account the changes in gas demand and supply patterns observed since the reduction of Russian gas importation in Europe;
- Scenario “C”, taking into account the changes in gas demand and supply patterns observed since the reduction in Russian gas importation in Europe, as well as internal congestion on the French network in winter.

On the whole, CRE's analyses met with no opposition in principle during the workshop, although some participants wondered about their consequences in terms of changes in tariff levels and the attractiveness of the French market compared with other European markets. Following the workshop, CRE received additional contributions, some of which criticised certain flow scenarios presented by CRE, while others drew CRE's attention to TSO maintenance operations affecting capacity availability.

Most of the participants were in favour of scenario B, which makes it possible to use flow scenarios assumptions that are easily justifiable and enforceable, and provides a better distribution of the tariff increase over the various entry and exit points of the main natural gas transmission system.

CRE plans to adopt this scenario for the structure of the main network for ATRT8.

5.2.2 Methodology for calculating reference prices

5.2.2.1 Distribution of main network and regional network costs, and storage compensation

5.2.2.1.1 Classification of services provided by the TSOs

Article 4 of the Tariff network code distinguishes between the services provided by the TSOs, the transmission services[19], and those that are ancillary services (non-transmission services)[20]. This article specifies that "*the transmission services revenue shall be recovered by capacity-based transmission tariffs*" and that "*the non-transmission services revenue shall be recovered by non-transmission tariffs applicable for a given non-transmission service*." The Tariff network code specifies that the non-transmission services tariffs shall comply with the following principles: *"a) cost-reflective, non-discriminatory, objective and transparent; b) charged to the beneficiaries of a given non-transmission service with the aim of minimising cross-subsidisation between network users."*

The services provided by the TSOs are classified as follows:

- transmission services: the services provided by the TSOs in the main network. Pricing in this network follows an entry/exit model and is based on capacity and distance;
- non-transmission services:
  - the services provided by the TSOs in the regional network. This network does not follow an entry/exit model since there is no entry charge. However, pricing in this network takes into account the distance compared to the main network. In addition, since only domestic clients use these networks, they bear 100% of the costs. Any cross-subsidisation between transit flows and flows destined for domestic consumption are therefore avoided;
  - storage compensation: collected by the TSOs from their clients and paid back to storage operators, this compensation does not aim to reflect the costs of a service provided by the TSO, but to compensate storage operators' allowed revenue in compliance with Article L. 452-1 of the energy code.

CRE's preliminary analysis

As there have been no significant changes in the structure or scope of these services since 2020, CRE plans to retain the same classification in the ATRT8.

Q39 : Are you in favour of maintaining the classification of services provided by the TSOs in the ATRT8?

5.2.2.1.2 General principles of the reference method

During the past tariff periods, the ATRT tariff was defined to meet several objectives, in particular:

- non-discrimination: network users incur the same costs for the same use of the network (the level of the tariff charges borne by users at a given entry or exit point in the French network remains identical regardless of the use of the point in question);
- reflect costs: the tariff aims to reflect the costs and send a relevant economic signal to network users, through, on the one hand, the use of relevant cost drivers (including capacity and distance) to set the tariff charges, and on the other hand, the launch of open seasons for long-term capacity reservations in order to ensure financing of network developments;
- acceptability of updates: tariff updates must be progressive and structural changes in the tariff must be duly justified and addressed in public consultations so that all stakeholders have sufficient and necessary visibility for the market to function properly.

CRE's methodology for calculating reference prices is based on the observation that a large majority of TSOs' costs are fixed costs that remain constant in the short term even if the use of the network varies (they represent roughly 90% of total costs in France). These costs are, for the most part, costs directly related to the level of investments and are therefore closely linked to investment strategy. This investment strategy is planned taking into account the network limits that must be lifted in order to guarantee the main flow scenarios and configurations.

In principle, in order for the tariff paid by each network user to perfectly reflect the costs, these costs must be distributed among network users generating investment needs. However, since the French transmission network is complex and heavily meshed, perfect reflectivity of costs is difficult to attain. A compromise must be found to

[19] "Transmission services", the regulated services that are provided by the transmission system operator within the entry-exit system for the purpose of transmission

[20] "Non-transmission services", the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the transmission system operator

maintain a sufficiently simple and stable transmission tariff. For that purpose, CRE defines in particular relevant flow scenarios which are described in the sections below.

5.2.2.1.3 Distribution of main network and regional network costs, storage compensation and connection with relevant flow scenarios

The costs related to the transmission network are distributed to avoid any cross-subsidisation between the different categories of network users:

- main network costs (roughly €1000 million/year) are considered as costs associated with transmission services[21] and are therefore allocated to two categories of network users (users accessing the network for transit, and those supplying domestic consumption);
- regional network costs (roughly €1,200 million/year) are considered as costs associated with non-transmission services[22], allocated only to users supplying domestic consumption, which are the only users;
- storage compensation costs (roughly €400 million on the 2020-2023 period) are considered as non-transmission services costs, allocated to domestic consumption.

For the ATRT7 period, the abovementioned distribution of costs was closely linked to and consistent with the definition of the relevant flow scenarios adopted to distribute the main network costs among the different categories of network users. In fact, the flow scenarios adopted by CRE in its methodology were those that enabled the allocation of regional network costs and storage compensation to domestic customers only:

- with regard to the regional network: the flow scenarios adopted by CRE take into account only the distance to reach the main network exit and not the distance to reach the end customer by crossing the entire regional network. Therefore, CRE has chosen to attribute regional network costs to domestic consumption, and the distance calculated to supply domestic consumption is reduced accordingly;
- with regard to the storage compensation: full gas storage facilities benefit all network users, including those transiting gas through France, because of a higher level of security of supply. However, CRE chose to exclude storage from the relevant flow scenarios for transit and therefore did not distribute the storage compensation costs across the different transit exit points.

CRE's preliminary analysis

CRE plans to adopt the same principles for ATRT8.

> Q40 : Are you in favour of the distribution of main network and regional network cost, as well as the storage compensation envisaged by CRE in the ATRT8?

5.2.2.1.4 Balance between costs and income attributable to the main network and the regional network

Since the first gas transmission tariffs were implemented, CRE has sought to ensure a balance, for each TSO, on the one hand, between costs assigned to the main network and the income its operation generates, and on the other hand, between the costs assigned to the regional network and the income its operation generates.

For the ATRT8 tariff period, CRE considers to maintain the principle of an average balance over the tariff period between main network and regional network costs and income.

Therefore, CRE requested the TSOs to distribute their costs between those relating to the main network and those relating to the regional network. This distribution is based on the following two principles:

- investment expenses and most operating expenses can be directly allocated to one of the networks by the TSOs and therefore are assigned to them;
- for a minor part of operating expenses that are too general for direct assignment (e.g. head office costs), the TSOs apply a distribution key: the expenses in question are generally distributed in proportion to network kilometres.

In accordance with these principles, over the ATRT8 period, the TSOs make the following forecast cost distributions, within the perimeter of France:

[21] As defined by the Tariff network code
[22] As defined by the Tariff network code

	Perimeter of France	
	% of main network expenses	% of regional network expenses
Average ATRT8	45%	55%

CRE's preliminary analysis

CRE considers that the level of tariff terms should therefore be set in the ATRT8 tariff in such a way that income collected on the main network represents around 45% of total income and income collected on the regional network represents around 55% of total revenue.

Q41 : Are you in favour of maintaining the balance between costs and income for the main and regional networks in the ATRT8?

5.2.2.2 Methodology for determining tariffs for large-scale transmission

5.2.2.2.1 Main principles of main network pricing

- **Capacity-based pricing**

In the ATRT7 tariff, the gas transmission tariff is based fully on subscribed capacity. In other terms, shippers pay for capacity they book, independently of the use they make of that capacity.

This pricing principle is compatible with the Tariff network code, which specifies, in its Article 4, that transmission services revenue is recovered by capacity-based transmission tariffs. This pricing method takes into account, in particular, the positive effect that predictable and stable sites have on the gas system, particularly in terms of investment reduction. Therefore, for equal consumption, the supplier of a thermosensitive customer must book more capacity, to cover peak consumption, which can be far from average consumption.

CRE's preliminary analysis

CRE considers to maintain the principle of 100% capacity-based pricing for ATRT8.

Q42 : Are you in favour of maintaining the principle of 100% capacity-based pricing for ATRT8?

- **Entry-exit system**

In ATRT7 tariff, the tariff structure of the main network is based on an entry/exit pricing principle. This principle enables network users to book their network entry and exit capacity separately and therefore to transport gas between the points of their choice. The tariff charges paid by users at the entry and exit points on the French network are identical, regardless of the origin and destination of the gas.

This entry-exit pricing principle complies with the provisions of (EC) regulation No. 715/2009 of 13 July 2009 concerning conditions for access to the natural gas transmission networks, which set out that the tariffs applicable to network users will be non-discriminatory and fixed separately for each transmission network entry and exit point.

CRE's preliminary analysis

CRE considers to maintain this entry-exit pricing system in the ATRT8 tariff.

Q43 : Are you in favour of maintaining the entry-exit pricing system for ATRT8?

- **Harmonisation of GRTgaz's and Teréga's tariffs**

The ATRT7 tariff provided for the harmonisation of a certain number of tariffs on a national scale. The tariffs at the Dunkerque, Virtualys, Obergailbach, Oltingue and Pirineos entry points are identical. This is also the case for the entry charges at the Dunkerque, Montoir and Fos entry points. The alignment of these charges offers shippers the possibility of choosing the most competitive source of supply.

In addition, the tariffs at the exits from GRTgaz's and Teréga's main networks to their regional networks are aligned.

The same applies to tariffs at the Transmission Storage Interface Points (PITS) on the Teréga and GRTgaz networks, with the exception of tariffs at the North-East and Atlantic PITSs, on which a 100% discount has been implemented from April 1, 2023 in order to facilitate storage subscription and guarantee security of supply.

CRE's preliminary analysis

CRE considers to maintain the principle of harmonising tariff terms for ATRT8. CRE also considers to re-establish the harmonisation of tariff terms at the PITS, given that market conditions have improved and now make it possible to ensure that storage facilities are adequately filled.

Q44 : Are you in favour of maintaining the harmonisation of main network tariff terms for ATRT8?

Q45 : Are you in favour of abolishing the 100% discount on the North East and Atlantic PITS tariffs from 1 April 2024?

- **Distribution of costs and income between main network entry and exit points**

In addition to seeking a balanced distribution of income and expenses between the main and regional networks, the distribution of income between main network entry points and main network exit points must also be considered.

In France, the entry/exit income ratio was 34/66 for the ATRT7 period.

The current distribution rate is the result of the presence in France of major storage capacity that covers winter peak consumption. Therefore, entry capacity subscribed by shippers in the French transmission networks is significantly lower than exit capacity booked.

The 50/50 distribution of income is included in the Tariff network code only for indicative purposes. This distribution is not relevant in a country such as France that has significant storage capacity.

CRE's preliminary analysis

CRE considers to maintain this ratio for the ATRT8 period.

Q46 : Are you in favour of maintaining the 34/66 entry/exit income ratio for ATRT8?

5.2.2.2.2 Method for calculating main network tariff charges

CRE considers to use the calculation method described below to calculate the tariff terms for the main network. This method is broadly similar to the one used for the ATRT7.

a) **Stages in the calculation of reference prices**

1) CRE considers retaining capacity and distance as the main cost drivers. Capacity booked is considered to determine the relevant flow scenarios used and to calculate the different distances (see point c).
2) The income received at the entry points and those received at the exit points are distributed based on the ratios envisaged by CRE, which are as follows: 34% at entry points and 66% at exit points. This historical ratio is due to the presence of significant storage capacity in France that leads to considerably less capacity booked at entry points than at exit points (see section 5.2.2.2.1).
3) Entry points are considered by CRE as three homogenous groups of points (IP, PITTM, and PITS) whose tariff charges are harmonised. Therefore, entry tariffs are determined by taking into account:
    i. forecast subscribed capacity at the different entry points;
    ii. a 60% discount applied to the PITS tariff terms, in order to take into account the role of storage facilities in terms of security of supply (cf. paragraph d).
4) Exit tariffs are determined following a methodology based on capacity and distance:
    i. definition of economically relevant flow scenarios to supply each exit point (see paragraph b and Appendix of the deliberation);
    ii. CRE then determined the shortest pipeline distance between the entry points and the exit points for each relevant flow scenario;

iii. this capacity-weighted distance is used to define the exit tariff charges in order to avoid cross-subsidisation between the different categories of network users. The unit costs (€/MWh/d/year/km) for cross-border customers and domestic customers are therefore identical;

iv. main network exits to regional networks are considered as a homogenous group of points and the tariff charges that are applied are equalised. This equalisation has no impact on the distribution of costs between transit and domestic customers.

b) Determination of relevant flow scenarios for calculating distances

- <u>Description and justification of the different flow scenarios considered</u>

As previously stated, CRE's methodology for calculating the reference prices is based on the observation that a large majority of TSOs' costs are fixed costs closely linked to the TSOs' investment strategy. This investment strategy is planned taking into account the network limits that must be lifted in order to guarantee the main flow scenarios and configurations.

Therefore, CRE defines the relevant flow scenarios so that they are based on predictable demand and supply patterns and, in addition, so that they are consistent with the TSOs' investment strategy, which means:

- that the flow scenarios are based on capacity subscriptions, with these subscriptions themselves being used to define the TSOs' main investment decisions;
- some of the historical subscriptions at entry and exit points of the French network coming to an end during the ATRT8 tariff period, that CRE also checks to make sure that the flow scenarios considered correspond to the expected functioning of the network during the tariff period to come.

  - **Relevant flow scenarios for domestic customers**

With regard to domestic flows, CRE considers that, from an economic point of view, there is no reason to favour one entry point over another to supply domestic customers. The entry points were in fact all decided on, at least in part, if not fully, to ensure supply of domestic consumption.

<u>Reminder of the ATRT7 scenarios</u>

Given, on the one hand, the configuration of the French network where main network entry points are well distributed across the French territory and, on the other hand, the fact that domestic consumption is mainly located close to borders, CRE considered for the ATRT7 tariff that each domestic client was supplied by the closest entry point as long as that point had available subscribed capacity remaining, with the exception of the Pirineos and Oltingue entry points. The Pirineos entry point was used very little to supply France despite a high level of subscribed capacity, while the Oltingue entry point was not subscribed.

<u>Scenarios envisaged for ATRT8</u>

CRE considers to maintain the principle of supplying each national consumer via the nearest entry point as long as there is subscribed capacity available. Since the change in demand and supply patterns following the reduction in supplies of Russian gas to Europe, the level of use of the Pirineos entry point has increased, and physical flows of gas from Spain are regularly observed in France: CRE therefore considers to retain it as a supply point for French consumers. On the other hand, as the Oltingue entry point has still not been subscribed, CRE plans not considering it as an entry point.

CRE therefore considers to adopt flow scenarios in which each national consumer is supplied by the nearest entry point as long as there is subscribed capacity available, with the exception of the Oltingue entry point.

  - **Relevant flow scenarios for transit users**

<u>Reminder of the ATRT7 scenarios</u>

For the ATRT7 tariff, CRE considered the IP Dunkerque as the entry point of gas transiting the French networks up to the IP Pirineos and to the IP Oltingue to determine the relevant flow scenarios for transit.

These flow scenarios reflect the network configurations that justified the level of investments in the network, and therefore, the TSOs' fixed costs. These investments were decided based on flow scenarios, considering that to ensure firm capacity at cross-border exit points, the network must be able to ensure sufficient internal capacity in the French network to ship gas from Dunkerque.

Furthermore, CRE considered that the other flow scenarios were not economically relevant for transit. These flows are not the ones taken into account to make investment decisions. They were also excluded for the reasons below:

- Exclusion of LNG terminals (PITTMs) as relevant entry points for transit: since Spain and Italy have their own LNG terminals, it is more relevant to consider that LNG would be shipped directly to those two countries rather than passing through France, in situations where LNG is economically attractive compared to gas shipped by pipeline.

- Exclusion of the IP Obergailbach as a relevant entry point for transit to Italy through the Oltingue exit point:

Historically, the IP Oltingue was developed in response to a transit need in order for gas to be shipped from Norway to Italy through the IP Dunkerque, as an alternative to a possible reinforcement of the German network (which would allow gas to be brought from Russia). Not only was the route through France more competitive than the route through Germany, the development of this entry point also reinforced Italy's security of supply by offering access to another source of supply.

In addition, passing through this IP to ship gas to Italy would involve paying an entry tariff at the IP Obergailbach then an exit tariff at the IP Oltingue, whereas it is possible to adopt a shorter and less costly route by passing through other routes such as Germany-Switzerland-Italy or Austria-Italy. These latter routes are less costly even with a tariff charge of zero at Oltingue.

- Exclusion of the IP Virtualys as a relevant entry point for transit to Italy through the Oltingue exit point:

In order to supply Italy with gas from Norway, a route through Belgium then the Taisnières H entry point is also technically possible. However, it is more economically relevant to ship gas through the entry point at Dunkerque and to use Oltingue for its exit.

- Exclusion of the other IPs of the north of France to supply Pirineos:

In the case of Pirineos, the economic competitivity and flows observed from the entry point at Dunkerque are such that maintaining firm capacities from Dunkerque to Pirineos has served, to a large extent, for the size of the investments necessary for the merging of zones. However, considering one of the other two entry points in the north of France would only slightly change the distances covered by gas to supply Pirineos.

Scenarios envisaged for ATRT8

The last few months have seen a significant change in gas supply and demand patterns in Europe, and a fortiori in France, due to the interruption in Russian gas supplies. Previously, gas flows were mainly from the north and east of France to the south and west. These are now mainly from the south and west of France, with an increase in gas supplies from Spain (via Pirineos) and LNG terminals.

These significant changes mean that the flow scenarios will have to be adapted from those used for the ATRT7. CRE therefore considers the following changes:

- Inclusion of LNG terminals (PITTM) as relevant entry points for transit: given the decrease in Russian gas supplies, LNG arriving in France is no longer used solely to supply French consumers, but also for transit, including to countries with their own LNG supply capacities, such as Spain and Italy;
- Inclusion of the Virtualys IP as a relevant entry point for transit to Italy via the Oltingue exit point, to reflect the supply of LNG to Italy from Belgium (or from the Netherlands via Belgium);
- Taking account of the Northern France IPs to supply Pirineos: the expiry of the long-term contracts signed at Dunkirk and the need to diversify sources of supply make it appropriate to take account of all the French IPs to supply Spain.

However, CRE considers it appropriate to maintain the exclusion of the Obergailbach IP as a relevant entry point for transit to Italy via the Oltingue exit point, as shorter and less costly routes via other routes such as Germany-Switzerland-Italy are more relevant.

With regard to the Obergailbach exit point created during the ATRT7, CRE considers to exclude the Virtualys IP as a relevant entry point, as Belgium and Germany are directly interconnected.

Consequently, at this stage, CRE is considering flow scenarios in which each exit point to cross-border countries is supplied by the nearest IP or PITTM as long as there is subscribed capacity available, with the exception of the Obergailbach entry point for Oltingue, and the Virtualys entry point for Obergailbach.

  - "Summer" and "winter" flow scenarios

CRE considers to keep two flow scenarios, a "summer" scenario (7 months) and a "winter" scenario (5 months) in order to model the different flow scenarios:

- in the "summer" scenario, the IP and PITTM entry points are used to fill the underground gas storage capacities, and to supply the transit exit points and national consumers in proportion to their annual reference consumption;
- in the "winter" scenario, the IP and PITTM entry points are used to supply the transit exit points, and national consumers are supplied in proportion to their peak consumption with gas from the IP and PITTM entry points and the storage facilities.

Q47 : Do you have any comments on the flow scenarios envisaged at this stage by CRE?

- <u>Resulting distances</u>

For transit

The flow scenarios presented above result in the weighted average distances below for IP exit points. They result from the shortest distance between the entry point and the relevant exit point, weighted by capacity if an exit point is supplied by several entry points.

- a distance of 672 km for the Obergailbach exit point;
- a distance of 674 km for the Oltingue exit point;
- a distance of 830 km for the Pirineos exit point.

For domestic consumers

These scenarios result in more than 600 relevant flow scenarios being defined (one for each exit point to the regional network). For each scenario, the distance is calculated as the shortest distance between the relevant entry point and the relevant exit point. The list of flow scenarios is given in appendix of the public consultation. The distances obtained vary from 1 km to 883 km.

Since the exit tariff terms to the regional network are equalised, CRE considers using the average distance covered by the capacities to supply national consumers, i.e. 249 km. It should be emphasised that this equalisation means that a single distance (equal to 249 km) is used for the supply of all the points in the country, including those located close to the exit points at the interconnections, for which a different distance is used in the framework of flow scenarios (see previous paragraph). However, the fact of using a single average distance and therefore equalising the output terms to the regional network has no impact on the overall distribution between the costs allocated to transit flows and those allocated to domestic flows.

- <u>Compliance with the Tariff network code</u>

The use of relevant flow scenarios is compatible with the Tariff network code. This code specifies:

- In its Article 8 (1) that: "*the parameters for the capacity weighted distance reference price methodology shall be as follows:* [...] *c) where entry points and exit points can be combined in a relevant flow scenario, the shortest distance of the pipeline routes between an entry point or a cluster of entry points and an exit point or a cluster of exit points d) combinations of entry points and exit points, where some entry points and some exit points can be combined in a relevant flow scenario".*
- In its Article 3 (20): "*flow scenario' means a combination of an entry point and an exit point which reflects the use of the transmission system according to likely supply and demand patterns and for which there is at least one pipeline route allowing to flow gas into the transmission network at that entry point and out of the transmission network at that exit point, irrespective of whether the capacity is contracted at that entry point and that exit point".*

CRE considers to determine the relevant flow scenarios for transit and domestic customers in compliance with the abovementioned provisions.

- <u>Compliance with an entry-exit system</u>

In an entry-exit system, network users must be able to buy entry and exit capacity separately. They can therefore transport gas from any entry point to any exit point, with the TSO being responsible for the management of flows in its network. The tariff charge at a given entry and exit point in the network must be identical, regardless of the origin and destination of the gas.

In that regard, using relevant flow scenarios in no way calls into question the principle of pricing based on an entry-exit system. Not only will network users still be able to book their network entry and exit capacity separately, and therefore, transport gas from any entry point to any exit point, the level of charges that users will pay at a given entry and exit point in the French network will also remain identical regardless of the origin and destination of the gas.

The relevant flow scenarios are only taken into account by CRE to define the level of these tariffs. This level is set to reflect the costs borne by the TSOs for the use of the network and the associated investments, which depend mainly on two factors: capacity and distance.

- <u>Conclusion</u>

In the light of the abovementioned elements, CRE considers that its envisaged methodology for calculating reference prices complies with the Tariff network code. These scenarios reflect the use of the network through predictable demand and supply patterns for which CRE verifies the consistency and the reality. The set of flow scenarios taken into account by CRE enable the allocation to each category of network users the costs related to the constraints they generate.

Q48 : Do you have any comments on the methodology for calculating reference prices envisaged at this stage by CRE?

c) **Subscribed capacity considered**

The subscribed capacity considered by CRE to set the ATRT8 tariffs are presented in the table below (cf. part 4.8):

MWh/d/year (on average over the ATRT8 period)	Entry capacity subscribed	Exit capacity subscribed
IP Virtualys	188 500	19 000
IP Taisnières B	[Confidential]	0
IP Dunkerque	550 000	0
IP Obergailbach	218 200	50 000
IP Oltingue	0	190 000
IP Pirineos	252 800	54 000
IP Dunkerque	370 000	
PITTM Fos	407 300	
PITTM Montoir	382 000	
PITTM Le Havre	110 000	
PITS Nord Ouest	394 500	213 000
PITS Atlantique	634 500	320 000
PITS Sud-Est	644 500	110 000
PITS Nord B	66 500	42 000
PITS Nord Est	176 000	125 000
PITS Sud-Ouest	556 000	300 000
Exit to regional network		*3 900 000*

d) **Adjustment of the tariffs at storage entry and exit points**

Article 9 of the Tariff network code provides for a discount of at least 50% to be applied to capacity-based transmission tariffs at entry points from and exit points to storage facilities. CRE has set a discount of 80% on the PITS tariff terms for ATRT7.

For ATRT8, CRE considers to keep the proportion of the main network's authorised revenue collected at the PITS constant compared with ATRT7 (i.e. around 6%), which corresponds to a discount of 60% applied to the PITS tariff terms. This level ensures that the attractiveness of storage facilities is not reduced, that there is an incentive to fill them and that their role in the smooth operation of the system and in terms of security of supply is taken into account. The revenue shortfalls resulting from this discount, on the entry and exit respectively, are offset by an adjustment of the other entry terms on one side and exit terms on the other side.

e) **Consistency of unit costs**

Article 5 of the Tariff network code specifies that an assessment of the allocation of transmission services revenue must be performed in order to measure the degree of cross-subsidisation between intra-system (domestic consumption) and cross-system network use, based on the reference price calculation methodology considered. This article also specifies that any difference in the allocation of these costs, exceeding 10%, must be justified.

The result of the cost allocation comparison indexes defined in this article and in application of the reference price's calculation model considered by CRE, is equal to **0%.** The methodology for elaborating the tariff grid proposed by CRE results in an identical unit cost for the different transit routes and for the supply of domestic clients.

The calculation of comparison indexes is summarised below. It takes into account the average of subscription hypothesis assumptions over the ATRT8 period:

- <u>Case of domestic consumption</u>

The supply of 1 MWh/d/year to a domestic customer requires on average, taking into account subscriptions of storage capacities, the subscription of 0.57 MWh/d/year of entry capacities in France (IP/PITTM), 0.63 MWh/d/year of entry capacities (withdrawal) at the PITS. These ratios are calculated on the basis of subscribed capacity (on average over the ATRT8 period). Furthermore, subscribing 0.63 MWh/d/year of entry capacity at the transmission storage interface points (PITS) (withdrawal) requires subscribing 0.28 MWh/d/year of exit capacity (injection) at the transmission storage interface points (PITS).

$$Ratio_{cap}^{intra} = \frac{\text{Revenue}_{\ cap}^{\ intra}}{\text{Driver}_{cap}^{intra}} = \frac{(entry\ tariffs\ + TCS) * exit\ capacity\ to\ regional\ network}{\text{Domestic consumption supply distance} * \text{ capacities}}$$

$$= \frac{(0.57\ \times\ TCE_{\ IP/PITTM} + 0.63\ \times\ TCES_{\ PITS}\ + 0.28\ \times\ TCSS_{\ PITS} + TCS_{\ to\ RR}) * 3{,}900{,}000}{249 * 3{,}900{,}000} = 0.83$$

Where:

- $Revenue_{cap}^{intra}$ is the revenue defined in a monetary unit such as the euro, which is obtained from capacity tariffs and charged for intra-system network use;
- $\text{Driver}_{cap}^{intra}$ is the value of capacity-related cost driver(s) for intra-system network use, such as the sum of the average daily forecasted capacities contracted at each intra-system entry point and intra-system exit point, or cluster of points, and is defined in a measurement unit such as MWh/day. <u>The cost drivers considered by CRE are capacity and distance;</u>
- TCE: tariff at IP or PITTM entry;
- TCES: tariff for entry from PITS (withdrawal);
- TCSS: tariff for exit to PITS (injection);
- TCS: tariff for exit to regional network.

- <u>Case of transit:</u>

The supply of 1 MWh/day/year of a transit user requires the subscription of 1 MWh/day/year of entry capacity to France (IPs/PITTM).

$$Ratio_{cap}^{cross} = \frac{\text{Revenue}_{\ cap}^{\ cross}}{\text{Driver}_{cap}^{cross}} = \frac{(\text{entry tariffs} + \text{exit tariffs}) * \text{transit exit capacity}}{transit\ supply\ distances * transit\ capacities}$$

In the case of transit to Obergailbach:

$$= \frac{(TCE_{\ IP/PITTM} + TCST_{\ Obergailbach}) * 50\ 000}{50\ 000 * 672} = 0.83$$

In the case of transit to Oltingue:

$$= \frac{(TCE_{\ IP/PITTM} + TCST_{\ Oltingue}) * 190\ 000}{190\ 000 * 674} = 0.83$$

In the case of transit to Obergailbach:

$$= \frac{(TCE_{\ IP/PITTM} + TCST_{\ Pirineos}) * 54\ 000}{54\ 000 * 830} = 0.83$$

Where:

- $\text{Revenue}_{cap}^{cross}$ is the revenue, defined in a monetary unit such as the euro, which is obtained from capacity tariffs and charged for cross-system network use;
- $\text{Driver}_{cap}^{cross}$ is the value of capacity-related cost driver(s) for cross-system network use, such as the sum of the average daily forecasted capacities contracted at each cross-system entry and exit point, or cluster of points, and is defined in a measurement unit such as MWh/day. The cost drivers considered by CRE are capacity and distance.
- TCE: tariff at IP or PITTM entry;
- TCST: tariff at IP exit;

$$Comp_{cap} = \frac{2 * (Ratio_{cap}^{intra} - Ratio_{cap}^{cross})}{Ratio_{cap}^{intra} + Ratio_{cap}^{cross}} = \frac{2 * (0.83 - 0.83)}{0.83 + 0.83} = 0$$

The methodology for calculating reference prices adopted by CRE results in an identical unit cost for the different categories of network users.

Q49 : Do you have any comments on the consistency of unit costs for the various transit routes and for supplying domestic customers?

5.2.2.2.3 Specific case of the PIV Virtualys

The interconnection at Alveringem was created within the framework of the commissioning of the Dunkerque LNG terminal in 2016, and enables non-odourised gas to be shipped from France to Belgium. Two types of capacity are sold:

- a direct entry capacity in Belgium from the Dunkerque LNG terminal sold by Fluxys, which, for that purpose, contracts a service with GRTgaz for shipping between the Dunkerque and Alveringem terminal;
- an interconnection capacity between the TRF and the Belgian market sold in a coordinated manner by GRTgaz and Fluxys within the Virtualys virtual interconnection point (PIV).

Given the short distance covered in France by the non-odourised gas being shipped to Belgium, a distance-based pricing principle cannot be adopted because it would not cover the development costs for the interconnection created. In addition, since exit capacity at the PIV Virtualys is no longer contracted as from 2020, a “Capacity x Distance” model cannot be applied.

In its deliberation of 12 July 2011[23], CRE adopted a pricing system for exit capacity at Alveringem based on the actual cost of investment observed at the end of work and on the total capacity level. In other words, the exit tariff at the PIV Virtualys was calculated based on an economic test so that subscriptions at this point in the network cover a sufficient part of the related costs. This reasoning is in line with the spirit of the provisions adopted retrospectively on 16 March 2017, in the Tariff network code (chapter IX) and the CAM network code (chapter V) concerning the development of incremental capacity. The deliberation of 12 July 2011 specifies that the exit tariff at the PIV Virtualys will change in compliance with the rest of GRTgaz’s tariff.

CRE considers to maintain these principles for the ATRT8 tariff.

Q50 : Are you in favour of maintaining the pricing principles for the Virtualys exit point for ATRT8?

5.2.2.2.4 Level of multipliers

Multipliers are applied to the main network tariffs: they mainly aim to maintain a high level of long-term subscriptions, by encouraging participants to book annual capacity rather than short-term capacity.

Article 13 of the Tariff network code specifies that for quarterly and monthly capacity products, the level of multipliers “*shall be no less than 1 and no more than 1.5*”. For daily and within-day capacity products, the level of multipliers is no less than 1 and no more than 3, except in duly justified cases.

[23] Deliberation by the French Energy Regulatory Commission deciding on the conditions for the connection of the Dunkerque LNG terminal to GRTgaz’s network and on the development of a new interconnection with Belgium at Veurne

The Tariff network code also specifies that several aspects should be taken into account to define these multipliers, including in particular:

- the balance between facilitating short-term gas trade and providing long-term signals for efficient investments in the transmission network;
- the impact on the transmission services revenue and its recovery;
- situations of contractual or physical congestion.

The coefficients applicable to the interconnection points in the ATRT7 tariff are presented in the table below:

Capacity	Special conditions	Coefficient	Multipliers
Quarterly	In the event of congestion*	1/4th of the annual tariff	1
	No congestion	1/3rd of the annual tariff	1.33
Monthly	In the event of congestion	1/12th of the annual tariff	1
	No congestion	1/8th of the annual tariff	1.5
Daily	In the event of congestion	1/30th of the monthly tariff	1
	No congestion	1/30th of the monthly tariff	1.5

*A point is considered congested if, upon allocation of the annual firm products at auctions, the capacity sale price is strictly above the reserve price and that at least 98% of the capacity marketed has been subscribed.

The current multipliers, which vary between 1 and 1.5, are within the limits set by the Tariff network code.

Operators' demand

Teréga is asking for the congestion tariff to be abolished in order to maximise the revenue collected at interconnection points and to maintain an incentive for users to reserve long-term capacity.

CRE's preliminary analysis

As regards the level of multipliers, CRE considers that the levels set have made it possible to meet the objectives of maintaining a high level of long-term subscriptions, and also to facilitate short-term exchanges and promote market integration and liquidity. At this stage, CRE is considering maintaining the same level of multipliers for ATRT8.

In the event that non-standard products would be marketed by TSOs during the ATRT8 tariff period, CRE considers that the multiplier for the standard product with a shorter duration be applied: for example, in the case of a seasonal product, the multiplier applicable to quarterly products would be applied.

Q51 : Are you in favour of CRE's positions regarding the level of multipliers?

In view of the fact that many long-term capacity reservation contracts at network interconnection points expired during ATRT7 and are expected to expire during ATRT8, CRE considers that the abolition of the congestion tariff could provide an appropriate incentive for players to subscribe long-term capacities. However, it considers it important not to limit access to capacity for players, so as not to undermine market integration and liquidity.

Q52 : Are you in favour of supressing the congestion tariffs?

5.2.2.2.5 Illustrative tariff grid for 2024

By way of illustration, and applying the methodology described above, CRE presents an example of evolution in the main tariff terms for GRTgaz's and Teréga's networks in 2024.
The tariff grid applicable in 2024 is summarised below. It is calculated on the basis of the illustrative authorised revenue for operators presented in section 4.9:

€/MWh/d/year	Current tariffs	Tariffs as at 1 April 2024	Tariffs as at 1 October 2024	Evolution
IP entries	105.70	105.70	126.16	+19.4 %
IP Taisnières B exit	81.99	81.99	98.13	+19.7 %
PITTM entries	95.13	119.70	119.70	+25.8 %
PITS entries	9.22	11.36	11.36	+23.3 %
IP Obergailbach exit	375.60	375.60	436.94	+16.3 %
IP Oltingue exit	386.85	386.85	437.99	+13.2 %
IP Pirineos exit	587.20	587.20	568.34	-3.2 %
IP Virtualys exit	42.05	42.05	48.46	+15.2 %
PITS exits	21.53	28.17	28.17	+30.8 %
Exits from main network to regional network	95.20	122.71	122.71	+28.9 %

This tariff grid shows a significant increase in tariff terms compared with ATRT7. For a given point, the tariff change between 2023 and 2024 is the result of several effects:

- the structural changes presented in section 5.2.2.2.2 (it should be noted that the structural changes considered by CRE have no impact on the overall revenue collected on the main network, all other things being equal);
- the drop in subscriptions expected during the ATRT8 period, presented in section 4.8;
- the increase in operators' charges compared with ATRT7 presented in section 4.

As indicated in section 3.2.2.4, CRE plans to apply a $Z_{national}$ variation to the main network tariff terms each year, with $Z_{national}$ = IPC + $X_{national}$ + $k_{national}$.

The tariff grid presented above corresponds to an $X_{national}$ set at 0, and the following inflation assumptions[24]:

	2025	2026	2027
Inflation (IPC)	1.80 %	1.60 %	1.60 %

Setting a higher $X_{national}$ term would imply a higher annual change in tariff terms, but would make it possible to limit the tariff increase between 2023 and 2024. For example, an $X_{national}$ set at 4% would correspond to the following changes between 2023 and 2024 for the main points on the main network:

[24] These assumptions will be updated for the deliberation.

	Evolution 2023/2024
IP entries	+14 %
PITTM entries	+20 %
IP Obergailbach exit	+11 %
IP Oltingue exit	+8 %
IP Pirineos exit	-8 %
Exits from main network to regional network	+23 %

Q53 : Do you have any comments on the tariff grid presented by CRE? In particular, do you think it would be preferable to smooth out the planned increase at the beginning of the tariff period?

5.2.3 Pricing of interruptible capacity

The Tariff network code states that tariffs for interruptible capacity[25] are calculated by multiplying the tariffs for firm capacity by the difference between 100% and a discount level calculated ex ante. The level of the discount depends on the probability of interruption of interruptible capacity and an adjustment coefficient A defined by the regulator.

Article 16 of the Tariff Network Code states that the probability of interruption can be calculated either per point or per set of points.

The tariff discounts currently in force in the ATRT7 tariff are summarised in the table below:

Main network entry-exit points	Discounts
IP entries	50%
Exits at IP Oltingue and Pirineos	15%
Exits at PITS	50%

Concerning interruptible capacity at IP entry points

Very little interruptible capacity was subscribed at most of GRTgaz's entry interconnection points during the current tariff period. The effective interruption rate for this interruptible capacity was very low (<5%). CRE considers that, given the low level of subscriptions, the interruption rates observed are not representative and cannot be used to set a discount. CRE therefore considers to maintain a 50% discount on IPs entering the GRTgaz network, as for the previous period.

Furthermore, on 1 November 2022, Teréga created additional interruptible entry capacity at Pirinéos. During its marketing period, the actual interruption rate for this capacity was 23%. Teréga is therefore requesting that the associated discount be lowered to 25% (compared with 50% today) to reflect the actual probability that the capacity will be interrupted.

CRE has no particular objection to Teréga's request.

Concerning interruptible exit capacity at the IPs

As no interruptible capacity was subscribed during ATRT7, and given the significant change in demand and supply patterns compared with the previous period, CRE considers that the effective interruption rates observed over previous periods are not representative. Consequently, CRE considers to maintain the current 15% discount.

[25] Gas transmission capacity that can be interrupted by the TSO under the conditions stipulated in the transmission contract. For information, the main parameters influencing the availability of capacity are the level of consumption and the configuration of the network.

Concerning exits at PITS:

In its deliberation of 29 May 2019[26], CRE introduced the interruption of exit capacity at the PITS above nominal levels, corresponding to the injection flows needed to fill the storage facilities within a reasonable timeframe.

CRE plans to maintain a 50% tariff rebate for interruptible capacity at the PITS.

Consequently, CRE considers to apply the following discounts to interruptible capacity for the ATRT8 period:

Entry-exit points on the main network	Discount
IP Dunkerque, Virtualys, Taisnière B and Obergailbach entries	50 %
IP Pirinéos entries	25 %
IP Oltingue et Pirinéos exit	15 %
PITS exits	50%

Feedback will be provided by the TSOs to determine the impact of flow changes on interruption probabilities.

Q54 : Are you in favour of Teréga's request to change the discount on interruptible capacity at the Pirineos entry IP?

Q55 : Are you in favour of the CRE's orientations for pricing interruptible capacity for GRTgaz and Teréga?

5.2.4 Pricing of backhaul capacity

5.2.4.1 Backhaul capacity at IP

“Virtual backhaul" capacity is capacity whose availability depends on the level of commercial flow in the main direction at the interconnection point concerned. Commercial gas flows from certain interconnection points at the France entry points, in particular with Germany (Obergailbach) and Belgium (Virtualys), have fallen sharply or have been interrupted, as gas prices on the German and Belgian markets have fallen below the French market price.

The value of backhaul capacity is suffering from two contradictory effects. On the one hand, decreases or interruptions in the physical flow reduce the availability (and therefore the value) of virtual backhaul capacity. On the other hand, changes in the gas price differential between the German or Belgian market and the French market have tended to increase the value of this capacity.

For backhaul capacity, CRE considers to maintain the 80% discount on the IP entry point tariff.

Q56 : Are you in favour of the orientations envisaged by the CRE concerning the pricing of backhaul capacity for GRTgaz?

5.2.4.2 Backhaul capacity at PITTM

5.2.4.2.1 Principle of the virtual liquefaction offer at LNG terminals

Elengy is proposing to create a virtual liquefaction service. The principle of this offer is to allow all shippers active on the transmission network to acquire LNG in tanks by making a "backhaul" nomination from the transmission network to the terminal, which reduces the terminal's send-out to the network. This "backhaul" nomination would be made at the intra-day allocation gate (and only when the terminal has the necessary flexibility). Dunkerque LNG plans to offer a comparable service.

In its public consultation of 10 November 2022[27], CRE presented the principles of this offer and questioned the market about its interest. Almost all of the players who responded to the public consultation were in favour of an in-depth study of this service by CRE with a view to its implementation for the ATRT8. However, some stakeholders

[26] Deliberation of the Commission de régulation de l'énergie of 29 May 2019 on the decision to amend the deliberation of 26 October 2017 on the operation of the single gas market area in France
[27] Public consultation no. 2022-13 of 10 November 2022 on changes to the tariffs for use of the gas transmission networks (ATRT7), storage facilities (ATS2) and regulated LNG terminals (ATTM6) from 1 April 2023

called for care to be taken to ensure that the introduction of this service did not adversely affect the regasification conditions of long-term subscribers.

The introduction of this service will require GRTgaz to adapt its offer at the PITTMs to enable commercial flows to exit the transmission system.

5.2.4.2.2 Description of GRTgaz's proposed offer

In order to take into account the virtual liquefaction offer from terminal operators, GRTgaz is proposing a change in the backhaul offer at the Montoir and Fos PITTMs, which would replace the existing offer at the Montoir and Fos PITTMs. This new backhaul service would also be extended to the Dunkerque LNG PITTM in addition to the Montoir and Fos PITTMs, for implementation from 1 April 2024.

GRTgaz proposes that, in line with the offer envisaged by the LNG terminals, the use of reverse capacity at the PITTMs should be invoiced on a pay-as-you-go basis, without prior subscription. The backhaul capacity available at the designated PITTM will be displayed in the morning for the same day and will correspond to the LNG terminals' offer. Advance subscription of capacity will not be offered because of uncertainties about the availability of virtual liquefaction at the terminals.

In order to limit the impact of the offer on congestion on the transmission system, the LNG terminals will only offer capacity from 9.15 a.m. when vigilance is green[28] on the network limits concerned by each terminal. The intra-day capacity proposed by GRTgaz would be firm in order to avoid operational complications at the terminals and to offer sufficient visibility to players downstream of the terminal (organisation of the logistics chain with tankers trucks and micro-tankers). Given that the volumes involved are very small in relation to the terminal's emissions to the transmission system, GRTgaz considers that interrupting the virtual reversal during the day would have very little impact on any congestion already in progress.

5.2.4.2.3 CRE's preliminary analysis

CRE points out that LNG terminals play a vital role in security of supply and preventing congestion on the gas transmission networks. CRE will therefore ensure that the development of new services at the terminals is not to the detriment of the permanent players who transport gas to France. CRE also points out that this offer must not undermine the quality of service provided by the terminals to shippers.

The creation of this service will be proposed in detail to the public and the market as part of the work on the next regulated tariff for the use of natural gas LNG terminals (ATTM7), due to come into force in 2025.

As regards the introduction of a virtual backhaul offer on the transmission network, at the Transmission-LNG Terminal Interface Points (PITTM), CRE considers that the terms and conditions of the offer are in line with the offer envisaged by the LNG terminal operators. Also, as the points are homogeneous, CRE considers that it would be desirable to equalise the tariffs for virtual backhaul on the transmission network.

CRE considers two methods for setting the tariff for virtual reversal at the PITTM on the transmission network:

- Set the tariff at the same level as entry to the PITTMs, i.e. €119.70/MWh/d/year (forecast for the 2024 tariff in the illustrative tariff grid in 5.2.2.2.5). The rate would thus be equivalent to that of a shipper physically loading gas by ship, who pays regardless of whether the gas is regasified or loaded in liquid form.
- Applying a discount on the entry term for the same point. Following the example of virtual discount on interconnection points (IP), the discount would be set at 80% of the entry tariff, which would set the annual tariff at €23.94/MWh/d/year (forecast for the 2024 tariff in the illustrative tariff grid in 5.2.2.2.5).

Q57 : Are you in favour of the tariffs for the use of virtual backhaul capacity at the PITTM envisaged by CRE?

5.3 Structure of the regional network

Pricing of transmission in the regional network depends on:

- the shipping capacity contracted;
- the unit tariff for transmission in the regional network multiplied by a regional tariff level (NTR), specific to each delivery point, which takes into account the disparity in transmission costs on the regional network for each delivery point, which depends mostly on the distance to the main network.

Pricing of delivery depends on:

[28] Intraday network flexibility indicator. Green vigilance does not require shippers to give advance notice of upward or downward changes to their schedules.

- the delivery capacity contracted;
- the unit delivery tariff (TCL) which differs depending on the type of delivery point;
- the number of delivery stations for industrial customers or industrial customers with major variations in consumption.

CRE plans to maintain the same principles for the ATRT8 tariff.

Q58 : Do you share CRE's position on maintaining the principles of regional network pricing?

5.3.1 Capacity pricing terms

5.3.1.1 Pricing of intra-annual capacity

Reminder of ATRT7 principles

At the main network exit and for transmission in the regional network and delivery, customers connected to the transmission network can book capacity for an annual, monthly or daily duration. These subscriptions give rise to an hourly delivery capacity equal to 1/20th of the daily delivery capacity contracted. They can also request additional hourly capacity, by paying an additional price.

The gas transmission network is sized to be able to ship the quantity of gas necessary to get through a 2% consumption peak risk (termed “P2”), i.e. the consumption peak at an extremely low temperature reached on three consecutive days, which occurs statistically once every 50 years.

This means that the network costs for a customer present only in the coldest months are close to the costs generated by a customer present all year. Therefore, CRE adopts pricing principles that encourage shippers to book mainly on an annual basis. It is possible to book intra-annual capacity by paying the cost of the annual capacity multiplied by a certain coefficient that depends on the duration of the product and the time of the year (with a higher coefficient in winter than in summer).

In addition, article D 452-1-2 of the energy code specifies that “*Tariffs for the use of the transmission networks applicable during the months of November to April can be set at a level higher than that enabling strict coverage of network costs, provided that they are adjusted downwards in the months of May to October, so as to maintain over the year the coverage of costs [...]”.*

Intra-annual capacity subscriptions are limited because the great majority of customers have their peak consumption in winter: they represent less than 4% of capacity booked by customers connected to the transmission networks.

The coefficients used in the ATRT7 tariff are as follows:

Capacity	Special conditions	Coefficient
Monthly	January - February - December	4/12 of the annual tariff
	March - November	2/12 of the annual tariff
	April – May – June – September – October	1/12 of the annual tariff
	July – August	0,5/12 of the annual tariff
Daily	No object	1/30 of the monthly tariff

CRE's preliminary analysis

CRE considers that the current coefficients are still relevant: it therefore plans to renew them for ATRT8.

Q59 : Do you share CRE's position on coefficients for intra-annual capacity?

5.3.1.2 Calculation of penalties for exceeding capacity

In the ATRT7 tariff, exceeding daily and hourly capacity is penalised as follows:

- for exceeding daily capacity, the calculation of penalties is based on the price of firm daily subscription of daily capacity;
    - for the portion in excess that is less than or equal to 3% of the daily capacity contracted, no penalty will be applied;
    - for the portion in excess that is greater than 3%, the penalty is equal to 20 times the price of the firm daily subscription of daily capacity;
- for exceeding hourly capacity, the excess is calculated by considering the maximum value of the hourly average of the quantities delivered at the given delivery point over four consecutive hours. Calculation of penalties is based on the price of the daily subscription of hourly capacity:
    - for the portion in excess that is less than or equal to 10% of the hourly capacity contracted, no penalty will be applied;
    - for the portion of the excess that is greater than 10%, the penalty is equal to 45 times the price of the firm daily subscription of hourly capacity.

The penalty rules for the ATRT7 tariff can be summarised as follows:

	Daily capacity (D)	Hourly capacity (h)
penalty cap	3%	10%
penalty	> 3% Penalty = daily price of daily capacity x 20	> 10% Penalty = daily price of hourly capacity x 45

CRE's preliminary analysis

CRE plans to maintain these pricing principles in the ATRT8.

Q60 : Do you share CRE's position on the pricing of exceeding capacity penalties?

5.3.2 Biomethane injection charges

5.3.2.1 Reminder of the current system

Law no. 2018-938 of 30 October 2018 on balanced trade relations in the agricultural and food sector and healthy, sustainable food accessible to all, known as the "EGalim law", introduced the principle of the right to injection for biogas producers. Article 94 introduced Article L. 453-9 into the Energy Code, which states that *"when a biogas production facility is located near a natural gas network, natural gas network operators shall carry out the necessary reinforcements to enable the biogas produced to be injected into the network, under conditions and within limits that ensure the technical and economic relevance of the investments [...]".*

The terms and conditions for implementing this article were set out in Decree no. 2019-665 of 28 June 2019 on the reinforcements to natural gas transmission and distribution networks required to enable the injection of biogas produced, and in the Order of 28 June 2019[29] implementing this decree.

The aforementioned decree of 28 June 2019, the provisions of which are now codified in articles D. 453-20 to D. 453-25 of the Energy Code, introduced three systems aimed in particular at the efficient development of bio-methane injection into natural gas networks:

- a zoning system for connecting biogas production facilities to a natural gas network. For each area of main-land metropolitan France located close to a natural gas network, the aim is to define the most appropriate network from a technical and economic point of view for the connection of a new biogas production facility located there. These zones must be approved by CRE;
- for reinforcement works, a system for assessing and financing the associated costs by the network opera-tors, within the limits of a technico-economic Investment/Volume ("I/V") ratio;
- for shared facilities that are not reinforcements, a system for sharing costs between producers in the same zone.

[29] Order of 28 June 2019 defining the terms and conditions for applying Section 6 of Chapter III of Title V of Book IV of the Energy Code

In its deliberation no. 2019-242 of 14 November 2019[30] (hereinafter the "Biomethane Deliberation"), CRE specified the operational procedures for implementing the right to injection, in particular those concerning the validation of reinforcement investments by DSOs, the process for which was specified in deliberation no. 2020-261 of 22 October 2020[31].

In addition, the provisions of articles L. 452-1 and L. 452-1-1 of the Energy Code stipulate that the costs borne by TSOs and DSOs[32] include part of the costs of connecting renewable gas production facilities, including biogas, or low-carbon gas production facilities to these networks, and that the level of coverage may not exceed 60% of the cost of the connection.

5.3.2.2 CRE has introduced a biomethane injection tariff in the ATRD6 and ATRT7 tariffs

All of the above-mentioned provisions lead to the pooling in the ATRD and ATRT tariffs of reinforcement costs in technically and economically relevant zones, as well as the majority of connection costs: this pooling does not necessarily encourage producers to make optimal location choices for the community.

With the aim of preserving an optimal location signal and covering the operating costs of the reinforcement works, CRE has introduced an injection charge into the ATRT7 and ATRD6 tariffs: based on the general principle of a three-level of injection charge, it is allocated to each generation site when the network operators submit the connection study (corresponding to milestone D2[33] in the queuing procedure), depending on the connection zoning[34] in force in the zone, and unchanged over the medium term. CRE may, however, decide to re-examine the situation of generation sites that have been assigned a level 3 after five years, if the backhaul[35] (or shared compression) has not been effectively implemented by this deadline.

The classification of zones by level is based on the connection zoning in force in the zone and is updated at the same time as the zoning is updated:

- if the zoning provides for a backhaul or mutualised compression, future production sites in the zone are assigned level 3;
- if the zoning does not provide for backhaul or mutualised compression:
    - if the zoning includes a mesh[36] and/or a shared extension[37], the production sites in the zone are assigned level 2;
    - for other zones, the production sites in the zone are assigned level 1.

To set the level of the injection charges, CRE studied the operating costs associated with the development of biomethane, with the exception of general OPEX costs, in particular those relating to the management of biomethane activities and the operation of the IT system: two categories of costs were evaluated over the period, (1) "backhaul OPEX " relating to backhaul and mutualised compressions, and (2) "pipeline OPEX" relating to meshes and other pipelines.

The following methodology has been applied:

- the forecast annual operating expenses for the period 2020-2023 were estimated by applying the following rates to the connection and reinforcement investment trajectories linked to the development of biomethane presented by the operators, corresponding to the network operators' technical and economic estimates:
    - 4% of investment costs (excluding studies) for mutual backhauls and compressions;
    - 0.2% for pipelines (meshes, shared extensions and other connection works);
- these costs have been allocated to the different zones, depending on whether or not they include a backhaul, and in line with the pipeline investments they require, in the zone's connection zoning;

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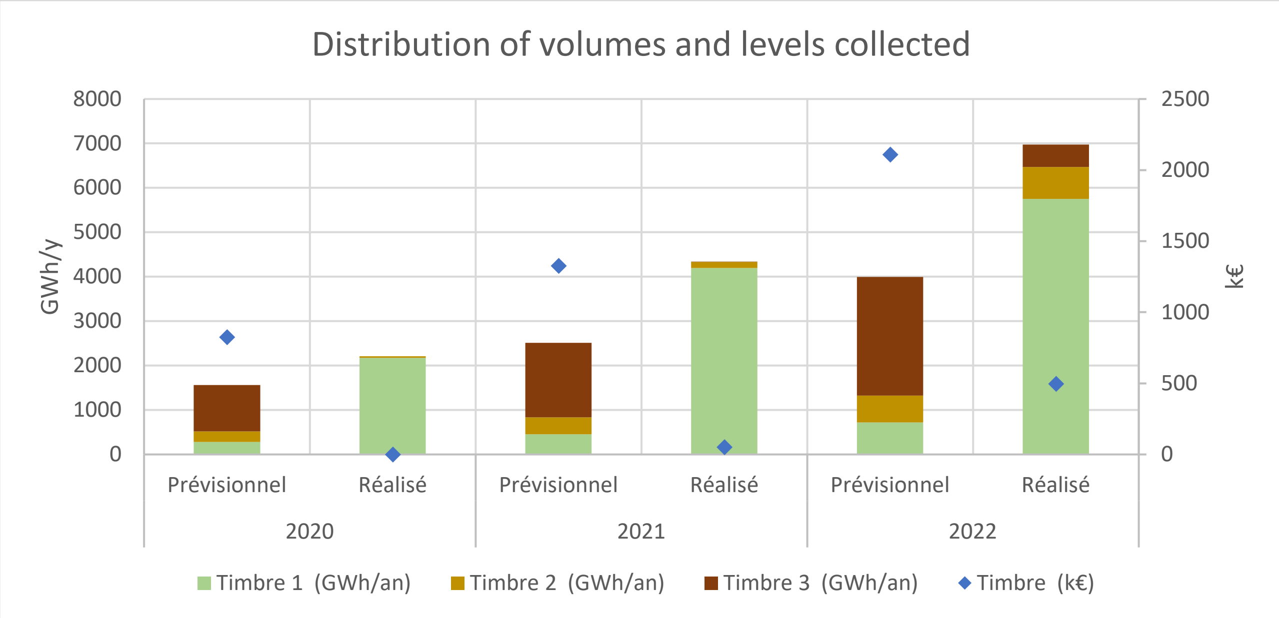
[30] CRE deliberation no. 2019-242 of 14 November 2019 on the mechanisms for integrating biomethane into gas networks
[31] CRE deliberation n°2020-261 of 22 October 2020 concerning the decision on the mechanisms governing the inclusion of biomethane in gas networks and validation of GRDF's distribution investments associated with the development of biomethane.
[32] For networks that are not licensed under article L. 432-6 of the Energy Code.
[33] Sites in the queue that have already passed milestone D2, but are not yet injecting biomethane, are assigned a charge level when the connection contract is signed, according to the same principles.
[34] Result of the study, carried out in consultation with the network operators, determining the optimum network configuration on the basis of the technical and economic zoning criterion.
[35] Compression installation enabling a flow of natural gas from a pre-existing section of a natural gas transmission or distribution network to a pre-existing section of a natural gas transmission or distribution network of higher pressure.
[36] Pipeline linking two pre-existing sections of one or more natural gas distribution networks, including, where applicable, a metering station at the network interface.
[37] Extension of a gas network to connect new sites, shared between several sites.

- the forecast volumes of biomethane injected for the period 2020-2023 have been calculated for each type of zone, excluding from the analysis capacity that has already been installed (which has been assigned level 1);
- the level of the charge was calculated as the ratio between the total anticipated OPEX over the period for each of the three types of zone and the total associated volumes by 2023 for each type of zone.

Feedback from the ATRT7/ATRD6 period

The costs recovered via this biomethane injection charge during the previous tariff period were significantly lower than the initial revenue forecasts, even though the volumes injected were higher than the forecast volumes. Nearly 7 TWh were injected in 2022, compared with the forecast volume of 4 TWh.



This revenue shortfall is mainly due to the fact that fewer projects were subject to the level 3 of the injection charge than expected. While the charge of level 3 was expected to apply to almost 2.7 TWh in 2022, it actually applied to only 0.5 TWh. This is partly due to the terms and conditions for applying the injection charge, which stipulated that sites that were not yet injecting when the ATRT7/ATRD6 tariffs came into force had to be allocated a charge when they signed their connection contract. According to GRDF, a large number of sites had already signed their connection contract, or were already injecting, and were allocated charge 1, at €0/MWh injected. CRE is pursuing its analysis of this point.

5.3.2.3 Changes envisaged for ATRT8

The biomethane sector is still developing, and is generating increasing costs for network operators, who must adapt their networks to accommodate new injection sites (reinforcement works to be developed, and some works to be switched from a distribution antenna function to a collection function).

CRE is considering several changes to the terms and conditions of the injection charge to take account of this dynamic.

On 10 May 2023, CRE organised a workshop to gather the views of stakeholders on how to take into account the increasing use of renewable and low-carbon gases. The workshop, which was attended by 85 participants, provided an opportunity to ask questions about the above-mentioned feedback and the changes planned for the next tariff period.

The feedback from the workshop participants provided CRE with food for thought on the changes considered relevant to implement for the next tariff period, as described below.

5.3.2.3.1 Renewal of the injection charges principle

The development over the coming years of renewable and low-carbon gas production and its injection will generate increasing costs for the networks. In its study on the future of gas infrastructures, CRE estimated the investment costs required to accommodate this production at between €200 million and €300 million per year up to 2050, around a quarter of which represents reinforcement investment. These investments will also generate additional operating costs, which will increase according to the number of km of additional pipelines and the volume of backhauls.

In this context, CRE considers that the locational signal sent by the injection charge remains primordial, so that producers are encouraged to optimise their capacities and their location on the networks. Among the operators, only Teréga was against maintaining this injection charge, considering it to be irrelevant and premature.

CRE is therefore considering maintaining the principle of an injection charge for the ATRT8 period.

5.3.2.3.2 Extension of the injection charges to all renewable and low-carbon gases

Since the ATRT7 tariff came into force, the right to injection scheme has undergone some changes. Since decree no. 2021-1273 of 30 September 2021[38], biomethane has been defined as "biogas whose characteristics allow it to be injected into a natural gas network" and biogas as "gaseous fuels produced from biomass".

The right to injection has therefore been extended from 2021 to all renewable gases, and no longer just to gases from methanisation plants.

In addition, article L. 453-9 of the Energy Code has been amended, stipulating that natural gas network operators must make the necessary reinforcements to enable renewable gas[39], including biogas, or low-carbon gas[40] produced to be injected into the network.

CRE is considering extending the injection charge, currently dedicated to biogas, to all renewable and low-carbon gas production sites, since producers of these gases also benefit from the right to injection. No objections were raised to this change at the workshop organised by CRE in May 2023.

> Q61 : Are you in favour of maintaining the principle of an injection charge and extending it to renewable and low-carbon gas production facilities?

5.3.2.3.3 Injection charge adaptations

CRE is considering two options for adapting the injection charge over the ATRT8/ATRD7 period.

The first option is to maintain the principles applied during the ATRT7/ATRD6 period, updating the cost parameters to take account of the trends observed during the ATRT7/ATRD6 period.

The normative rate for calculating operating costs would thus be maintained at 4% for mutualised backhauls and compressions, but increased from 0.2% to 0.6% for pipelines (meshes, mutualised extensions and other connection works) in order to take better account of the reality of maintenance and energy costs.

Under this option, the scope of costs covered would correspond only to the direct costs of operating the facilities (maintenance and energy charges).

GRDF has expressed a desire to bring the injection charge into line with the billing arrangements for the largest consumers, with no variation in level between zones. CRE is not in favour of such a change, as operating costs are higher in areas requiring reinforcement works.

With regard to changes in the parameters, GRTgaz and some of the participants are concerned about the increase in terms that it generates, considering that this increase was perhaps not a good signal given the forecast slowdown in the renewable gas sector. CRE points out that tariffs must be designed to reflect the costs of the users who generate them. At present, the tariffs applied to renewable and low-carbon gas producers, whose share of the gas network user base is set to increase, do not fully reflect the costs they generate, which leads to additional costs for gas-consuming users. CRE will nevertheless remain attentive to the acceptability of changes in bills for the industry.

The second option is to change the scope of the forecast operating costs taken into account when calculating the injection charge. As the sector has grown, it has generated structuring and operational costs for network operators that go beyond the maintenance and energy costs directly linked to the reinforcement structure. In particular, operators bear the costs of dedicated commercial and operational teams, research costs and information system costs.

CRE therefore plans to include these indirect operating costs associated with renewable and low-carbon gases in the cost base to be covered by the producers of these gases. Determined on the basis of GRDF's cost allocation method and a breakdown of the costs presented by operators as part of the tariff work, these indirect operating costs represent between €7 million and €12 million per year for gas operators (transmission and distribution). Between now and the publication of the public consultation on GRDF's ATRD, CRE will continue its analyses of the amount of these indirect operating costs.

Under this second option:

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[38] Decree no. 2021-1273 of 30 September 2021 amending the regulatory part of the Energy Code concerning special provisions relating to the sale of biogas

[39] Energy Code, art. L. 445-1: "Gases produced from renewable energy sources as defined in Article L. 211-2 are considered renewable.

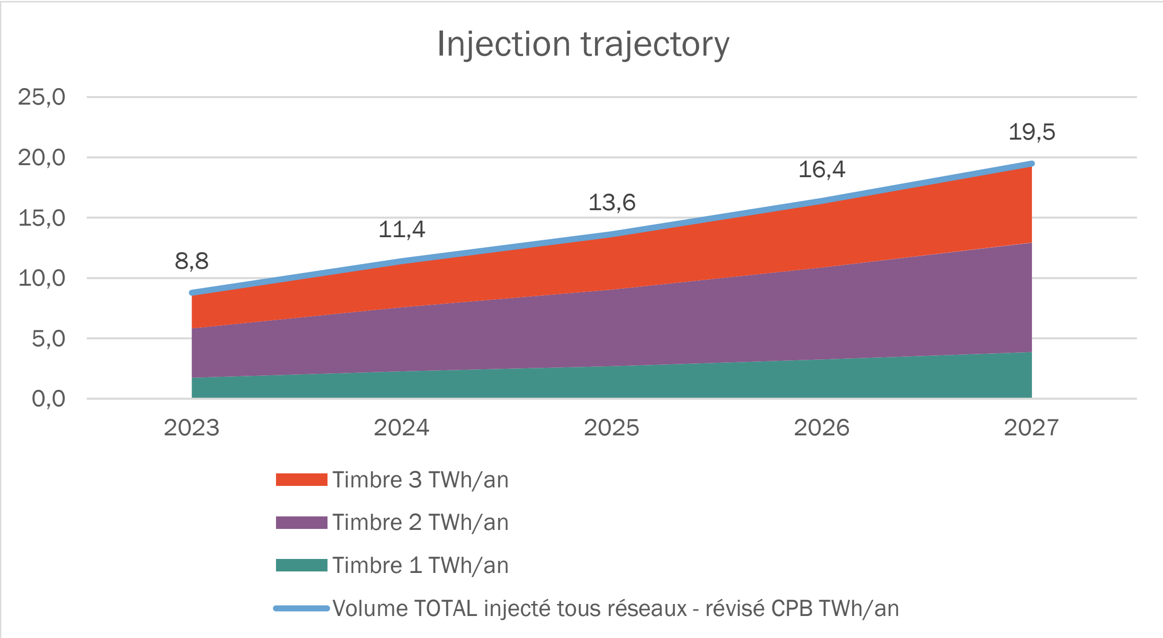
[40] Energy Code, art. L. 447-1: *"low-carbon gas is a gas consisting mainly of methane that can be injected and transported safely in the natural gas network and whose production process generates emissions that are less than or equal to a threshold set by order of the Minister responsible for energy. »*

- direct costs would continue to be collected in the same way as in option 1;
- indirect costs would be collected by adding a capacity charge: at this stage, CRE envisages that this charge would apply to the site's maximum production capacity, in MWh/d/year. A possible alternative solution would be a fixed annual term per site, which would however give an advantage to larger sites over smaller ones, an alternative that was not favoured by stakeholders at the workshop. This term would be the same for all projects, regardless of the connection zone.

Some participants in the 10 May workshop questioned CRE about the complexity and relevance of billing based partly on installed capacity and not on volumes injected. On these points, CRE considers that indirect costs, which are not borne by producers, are not directly variable costs, unlike energy or maintenance, but capacity costs, and that they should therefore be reflected in a term based on capacity. Furthermore, CRE considers the complexity of this new term to be limited, especially as this type of billing is already applied to certain consumers, in both distribution and transmission tariffs.

5.3.2.3.4 Planned injection trajectory and envisaged tariff grid

CRE is therefore considering a trajectory of 19.5 TWh injected into all networks combined in 2027:



Source: GRDF, GRTgaz, Teréga and CRE

This trajectory has been adjusted slightly in relation to the forecast trajectory communicated by the operators, with CRE questioning the rebound expected in 2027 due to the possible entry into force of biogas production certificates in 2025, considering that the time between the introduction of the mechanism and the effects on the industry is too short.

Taking these assumptions into account, **the levels of the injection charge tariff terms enabling direct costs to be recovered would be as follows:**

Charge level	Current grid (€/MWh injected)	Planned grid for ATRT8/ATRD7 (€/MWh injected)	*Of which backhaul OPEX (€/MWh injected)*	*Of which meshing and connection OPEX (€/MWh injected)*
3	0.7	1.8	*1.40*	*0.37*
2	0.4	0.4	*0.00*	*0.44*
1	0	0	*0.00*	*0.10*

If the scope of charges to be covered by the injection charge is extended to include indirect charges, estimates at this stage point to **an additional capacity charge** of between €120 and €200/MWh/d/year. At this stage, CRE is considering using a level within this range that is consistent with that of an entry charge on the GRTgaz or Teréga network**, estimated at €130/MWh/d/year** on average over the ATRT8 period (see section 5.2.2.2.5 of this public consultation). In fact, injection into the networks is akin to an entry point to the single marketplace, where gas is purchased and can be traded, and therefore represents the same service for its user. This point was also made by several participants at the workshop on 10 May 2023. This level will ensure that local, low-carbon production is not disadvantaged, and that the capacity term is limited to the level envisaged for the IPs.

> Q62 : Are you in favour of the principles, construction parameters and levels of the injection charge envisaged by CRE for ATRT8? Are you in favour of extending the scope of costs to be covered by the injection charge? Do you have any other suggestions concerning this scope of costs and the form to be given to the injection charge?

5.3.2.3.5 Reversal of the charge

To avoid multiplying the number of interlocutors for producers, CRE had retained for the ATRT7/ATRD6 period the principle of invoicing the injection charge by the grid operator to which each producer is connected. As a result, CRE has introduced a repayment to the TSOs of the revenue received by the DSOs for backhaul OPEX. The repayment is made on an annual basis, according to the volume of injection revenue actually collected during the year, for producers connected to the distribution network and allocated the level 3 injection tariff term. The volumes associated with these transfers between operators are taken into account in the CRCP at 100%.

CRE plans to renew these invoicing and repayment procedures.

The proportion of revenue received from the variable part of the level 3 injection tariff term that would be re-paid by the DSOs to the TSOs concerned is estimated at this stage at €1.4/MWh, corresponding to the share of backward OPEX.

In addition, if a capacity term is added, CRE also envisages a transfer to the TSOs of the revenue received by the DSO in respect of OPEX allocable to the TSOs, and vice versa. The terms and conditions of this solution will be announced during the public consultation on GRDF's distribution tariff.

The volumes associated with these transfers between operators would be taken into account in the CRCP at 100%.

> Q63 : Are you in favour of the principle of transferring to the TSOs the revenue received from the injection charge by the DSOs and associated with the operation of the backhauls and the TSOs' indirect operating costs?

5.3.3 Illustrative regional network tariff grid for 2024

The tariff grid for GRTgaz's and Teréga's regional networks in 2024 is summarised below. It is calculated on the basis of the illustrative authorised revenue for operators presented in section 4.9:

€/MWh/d/year		Current tariffs	Tariffs as at 1 April 2024	Evolution
GRTgaz	Terms of transmission capacity on the regional network (TCR)	84.29	98.35	+16.7 %
	Terms of delivery capacity (TCL)			
	End consumer connected to the transmission network	33.54	39.14	+16.7 %
	PIRR	43.06	50.25	+16.7 %
	PITD	49.52	57.78	+16.7 %
	Fixed term per station	6 472.55	7 552.42	+16.7 %
Teréga	Terms of transmission capacity on the regional network (TCR)	84.79	103.19	+21.7 %
	Terms of delivery capacity (TCL)			
	End consumer connected to the transmission network	30.73	37.39	+21.7 %
	PITD	55.52	67.57	+21.7 %
	Fixed term per station	3 398.63	4 135.81	+21.7 %

This tariff framework shows a significant increase in tariff compared with ATRT7. This is the result of several factors:

- the fall in subscriptions expected during the ATRT8 period, presented in section 4.8;
- the increase in operators' costs compared with ATRT7, presented in section 4.

As indicated in section 3.2.2.4, CRE plans to apply a $Z_{régional}$ variation to the tariff terms for regional networks each year, with $Z_{régional}$ = IPC + $X_{régional}$ + $k_{régional}$.

The tariff framework presented above corresponds to an $X_{régional}$ set at 0, and the following inflation assumptions[41]:

	2025	2026	2027
Inflation (IPC)	1.80 %	1.60 %	1.60 %

Setting a higher $X_{régional}$ term would imply a greater annual change in tariff terms, but would make it possible to limit the tariff increase between 2023 and 2024. For example, an $X_{régional}$ set at 3%, a level consistent with the annual fall in subscriptions, would be associated with a tariff increase between 2023 and 2024 of 12% on GRTgaz's regional network, and 19% on Teréga's regional network.

Q64 : Do you have any comments on the tariff grid presented by CRE? In particular, do you think it would be preferable to smooth out the planned increase at the beginning of the tariff period?

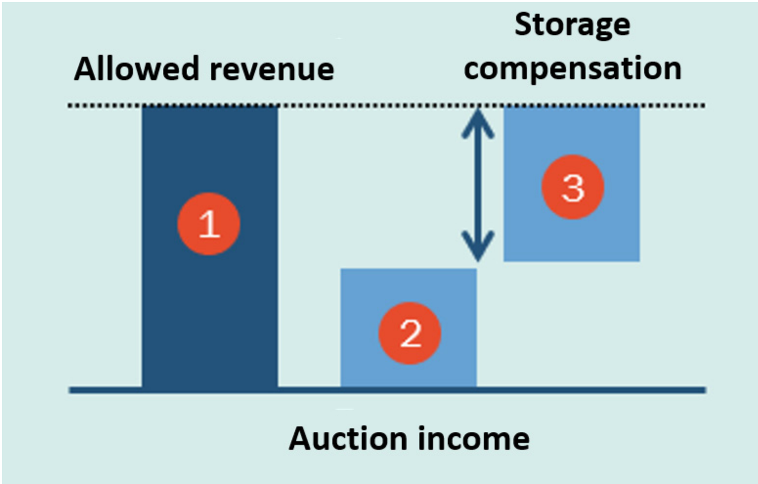
[41] These assumptions will be updated for the deliberation

6. STORAGE COMPENSATION

6.1 Principle of coverage for storage costs

Article L. 421-3-1 of the Energy Code states *that "The underground natural gas storage infrastructures that guarantee security of supply [...] are provided for in the multi-annual energy planning [...]. These infrastructures are kept in operation by the operators [...]"*. In return, and within the limits of the obligation to keep in operation the storage sites considered necessary for security of supply in the multi-annual energy programme, storage operators are guaranteed to have their costs covered, insofar as these costs are those of an efficient operator.

Within this framework, CRE sets, before 1st April each year, the amount of compensation, for each of the three storage operators, corresponding to the difference between the allowed revenue of the operators for the year in question and the forecasts of revenue linked to the commercialisation of storage capacity directly received by the operators.



Compensation is recovered from shippers present in GRTgaz's and Teréga's transmission network, by applying the storage charge, which depends on the winter modulation of their clients connected to the public gas distribution and transmission networks.

6.2 Scope of the storage compensation

In its deliberation of 22 March 2018[42], CRE defined the scope of the basis of the storage compensation collection. At 1 April 2018, the scope used corresponded to all consumers connected to the distribution network who had not contractually accepted a supply that was liable to be interrupted, or who had not declared that they could be unloaded.

This perimeter was chosen by CRE in view of:

- on the one hand, very tight deadlines for implementing the reform of third-party access to underground natural gas storage facilities and the need for continuity with the previous system;
- and on the other hand, the absence of a contractual interruptibility mechanism allowing consumers directly connected to the transmission network, who can interrupt their consumption in certain exceptional situations, to be exempted from payment of the storage tariff term.

Once the contractual interruptibility mechanism had been effectively implemented, CRE extended the compensation base to customers directly connected to the transmission system. This extension took place when the ATRT7 tariff was updated on 1 April 2021[43].

6.3 Calculation of winter modulation

All shippers who are allocated firm delivery capacity to at least one PITD or who supply a customer directly connected to the transmission network are charged a storage tariff term (TS) based on the winter modulation of the customers in their portfolio on the 1st day of each month. The purpose of this charge is to recover part of the income earned by operators of underground natural gas storage facilities.

The basis for collecting the compensation from each shipper is defined as the sum of the bases of each of its customers eligible for payment of the storage compensation.

The methods for calculating the modulation are specified in the tariff update decision[44].

The storage tariff term is calculated as the ratio between the forecast amount of compensation at the France level and the forecast value of the basis for collecting this compensation.

[42] CRE deliberation of 22 March 2018 on the decision to introduce a storage tariff term in the tariff for use of the GRTgaz and TIGF transmission networks
[43] CRE Deliberation no. 2021-15 of 21 January 2021 on changes to the tariff for use of the GRTgaz and Teréga natural gas transmission systems on 1 April 2021
[44] Deliberation of 12 January 2023 on decision on the annual evolution in the tariff for use of the GRTgaz and Teréga natural gas transmission networks from 1 April 2023

$$TTS = \frac{operator's\ allowed\ revenue - commercial\ revenue}{basis\ for\ compensation}$$

CRE's preliminary analysis

Since 2018, storage infrastructure operators have been subject to economic regulation. It stipulates that:

- storage capacities that guarantee security of supply are provided for in the PPE[45]. These infrastructures are kept in operation by storage operators;
- the income of storage operators is determined by CRE;
- storage capacity is sold by auction in accordance with the procedures defined by CRE;
- the difference, positive or negative, between the income mainly from auctions and the regulated income of storage operators is compensated by a tariff term determined by CRE within the tariff for use of the natural gas transmission network.

The aim of implementing regulation was therefore to guarantee that the storage capacity needed for security of supply could be subscribed and then filled, while at the same time providing transparency on costs. The regulation of operators' revenues also aimed to ensure that end consumers paid the right price for the storage needed to ensure security of supply.

These objectives have largely been achieved. Since the regulation came into force, almost all the capacity on offer has been allocated thanks to the auction mechanism, which enables storage to be sold at its market value. At the same time, the compensation mechanism between storage and transmission has made it possible to effectively cover operators' costs that were not reflected by the market value. At a time of serious crises (Covid, war in Ukraine) and volatile market conditions since the regulation of storage facilities came into force, this operation has ensured France's security of natural gas supply at a controlled cost.

Auctions have generated an average of €300 million a year in revenue, which represents 45% of operators' allowed revenue.

CRE considers that the storage compensation arrangements are appropriate and have proved their resilience in the face of the various shocks experienced by the European gas system since 2018. It plans to renew the current modalities for the next tariff period.

Q65 : Are you in favour of renewing the storage compensation modalities?

Q66 : Do you have any other comments?

[45] Multiannual energy programmes

APPENDIX 1: REVIEW OF THE TARIFF REGULATORY FRAMEWORK

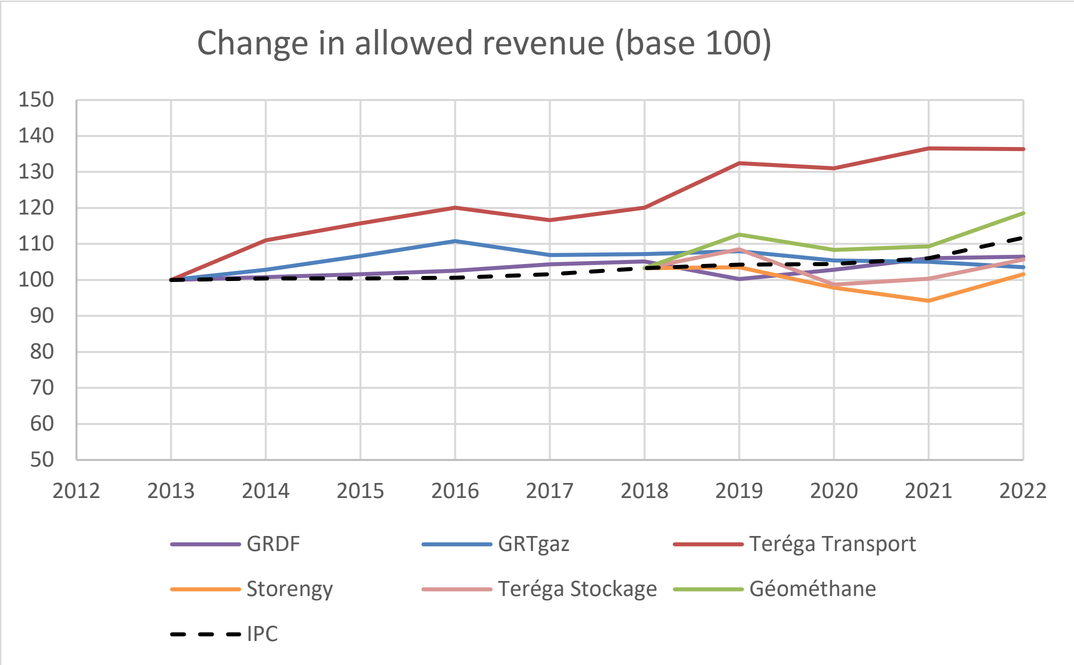
To assess the results of the regulatory framework, the following pages present a number of financial, non-financial and quality of supply and service indicators for the following operators:

GRDF (Natural gas distribution), GRTgaz (Natural gas transmission), Teréga (Natural gas transmission and storage), Storengy (Natural gas storage) Géométhane (Natural gas storage),

Financial items

1 Allowed revenue

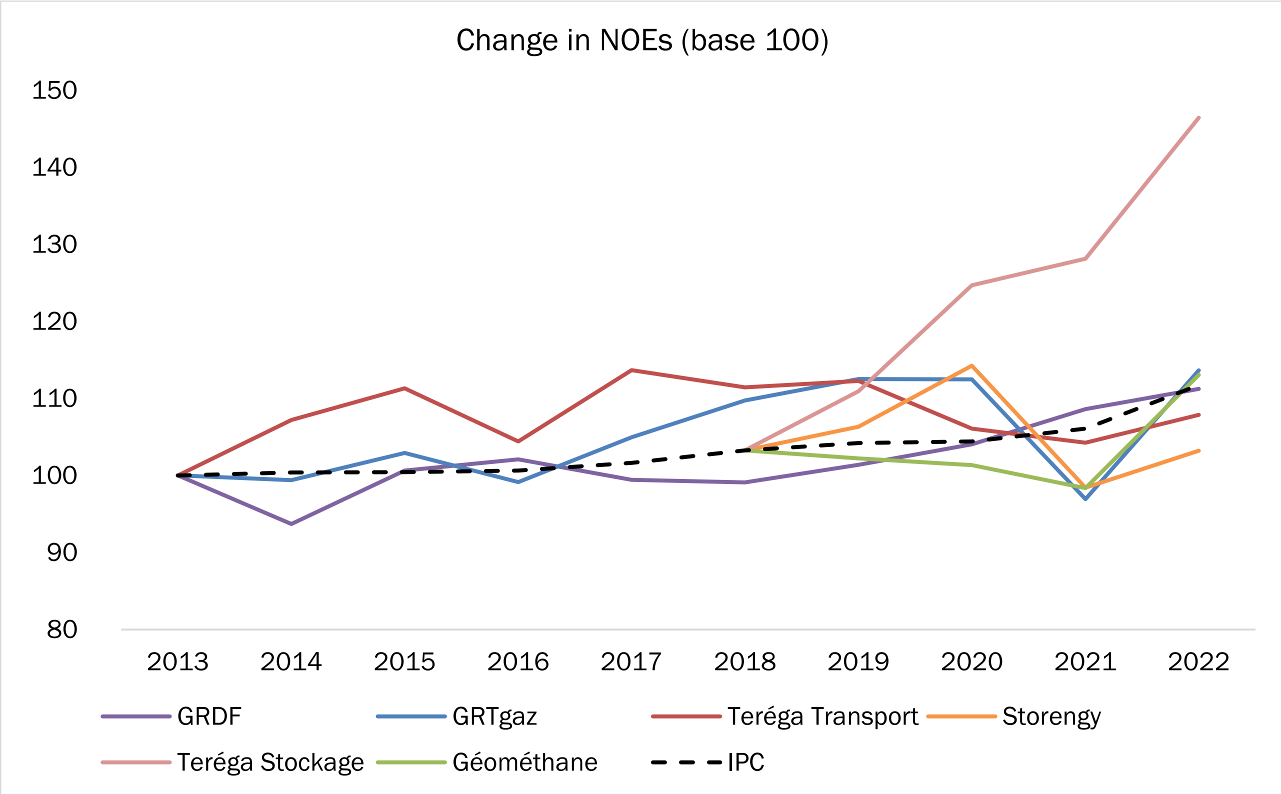
The allowed revenue for infrastructure operators is set by CRE and must cover the costs incurred by these operators insofar as these costs correspond to those of an efficient infrastructure operator. The revenue generated by the payment of tariff terms or components covers this allowed revenue. The change in Teréga's allowed revenue is particularly sensitive to the commissioning of major transport works between 2013 and 2016 (interconnections with Spain) and between 2018 and 2019 (creation of the single market area). The growth in allowed revenues for the other gas infrastructure operators has been close to that of inflation since 2013.



Year	GRDF (M€)	GRTgaz (M€)	Teréga Transmission (M€)	Storengy (M€)	Teréga storage (M€)	Géométhane (M€)
2013	3 088	1 662	205			
2014	3 113	1 710	228			
2015	3 138	1 773	237			
2016	3 168	1 842	246			
2017	3 222	1 777	239			
2018	3 248	1 782	246	523	153	38
2019	3 097	1 795	271	524	161	42
2020	3 175	1 752	268	496	147	40
2021	3 274	1 747	280	477	149	40
2022	3 288	1 721	279	515	157	44

2 Net operating expenses

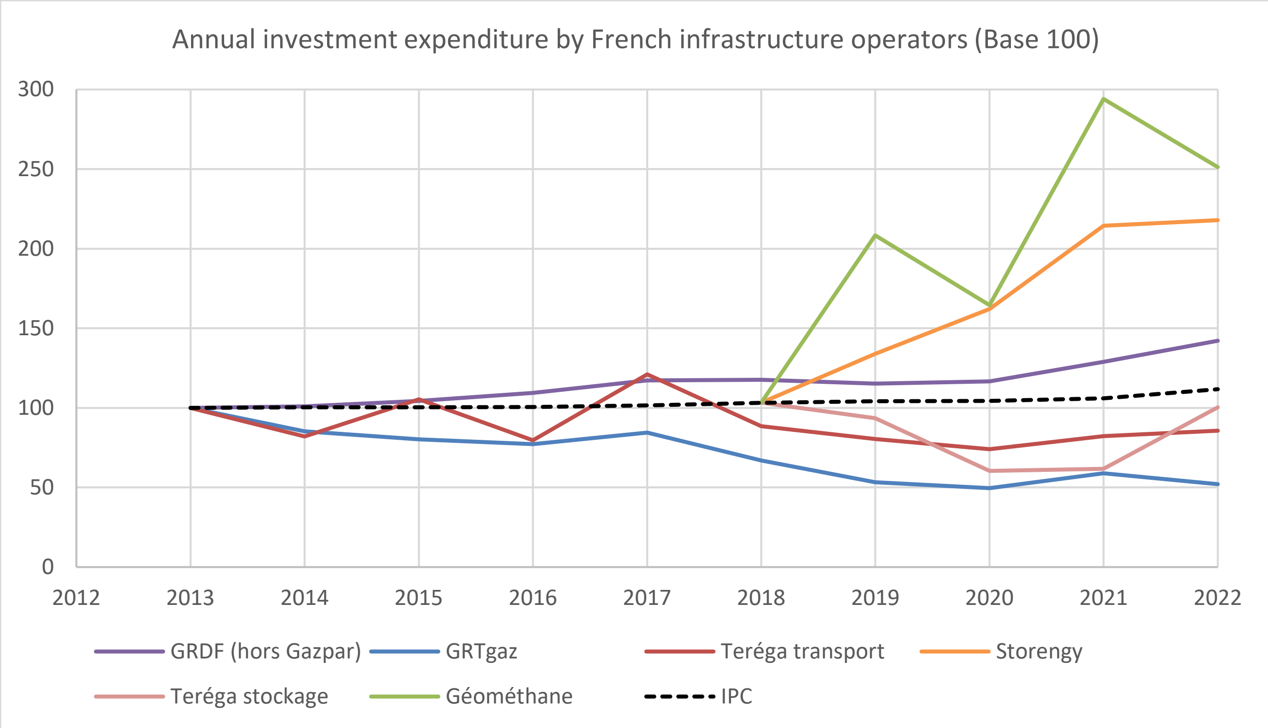
The graph below shows changes in the net operating costs of the various operators (gross operating costs less operating income such as capitalised production, extra-tariff income, etc.). Changes in the net operating costs of gas infrastructure operators have been close to those of inflation, except for Teréga storage.



Year	GRDF (M€)	GRTgaz (M€)	Teréga transmission (M€)	Storengy (M€)	Teréga storage (M€)	Géométhane (M€)
2013	1 414	702	67			
2014	1 325	697	72			
2015	1 423	722	75			
2016	1 444	696	70			
2017	1 406	736	76			
2018	1 401	770	75	161	37	17
2019	1 434	789	75	166	40	16
2020	1 471	789	71	178	45	16
2021	1 536	680	70	153	46	16
2022	1 573	797	72	161	53	18

3 Investments

The graph below shows the trend in investment by infrastructure operators in infrastructure excluding Gazpar advanced meter projects.



Investments (M€)	GRDF (excluding Gazpar)	GRTgaz	Teréga transmission	Storengy	Teréga storage	Géométhane
2013	659	777	125			
2014	666	663	103			
2015	688	624	132			
2016	721	600	100			
2017	772	657	152			
2018	776	520	111	99	58	12
2019	760	414	101	128	52	24
2020	769	385	93	155	34	19
2021	850	457	103	206	34	34
2022	937	405	107	209	56	29

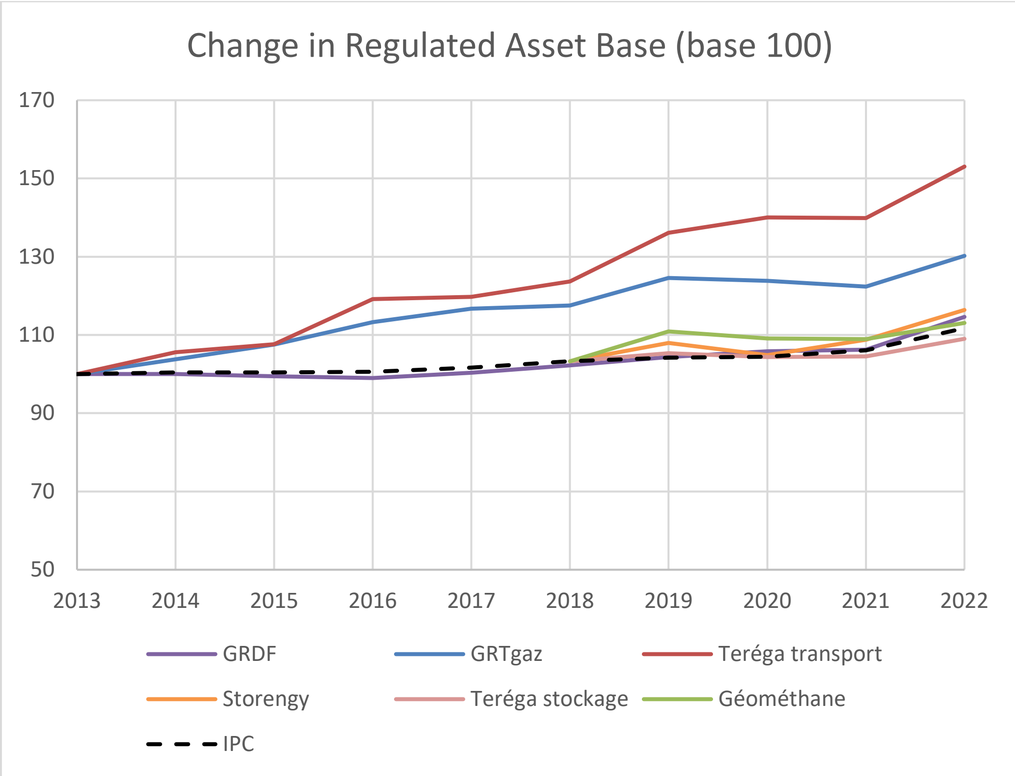
Investment by transmission system operators (TSOs) fell significantly after the completion, in 2018, of the merger of zones in France, which had necessitated major reinforcements of the gas transmission network. Since 2019, the level of investment has been stable overall.

With regard to natural gas distribution, capital expenditure has been rising since 2021 (excluding Gazpar smart meter projects) in order to ensure the connection of biomethane production sites and to meet increased safety requirements.

Investments by storage operators Storengy and Géométhane have been rising since regulation began in 2018. For Storengy, this is due to a catch-up of investments to maintain storage performance after a phase of under-investment before the start of regulation, when market conditions were particularly unfavourable for Storengy's storage facilities. For Géométhane, the increase is associated with site renovation work.

4 Regulated Asset Base

Investments made by operators are included in the regulated asset base (RAB) once they have been commissioned. The RAB decreases as the installations are depreciated. The RAB of gas infrastructure operators is adjusted annually for inflation. In constant euros, the RAB increases when new investments exceed the depreciation of existing assets, and vice versa.



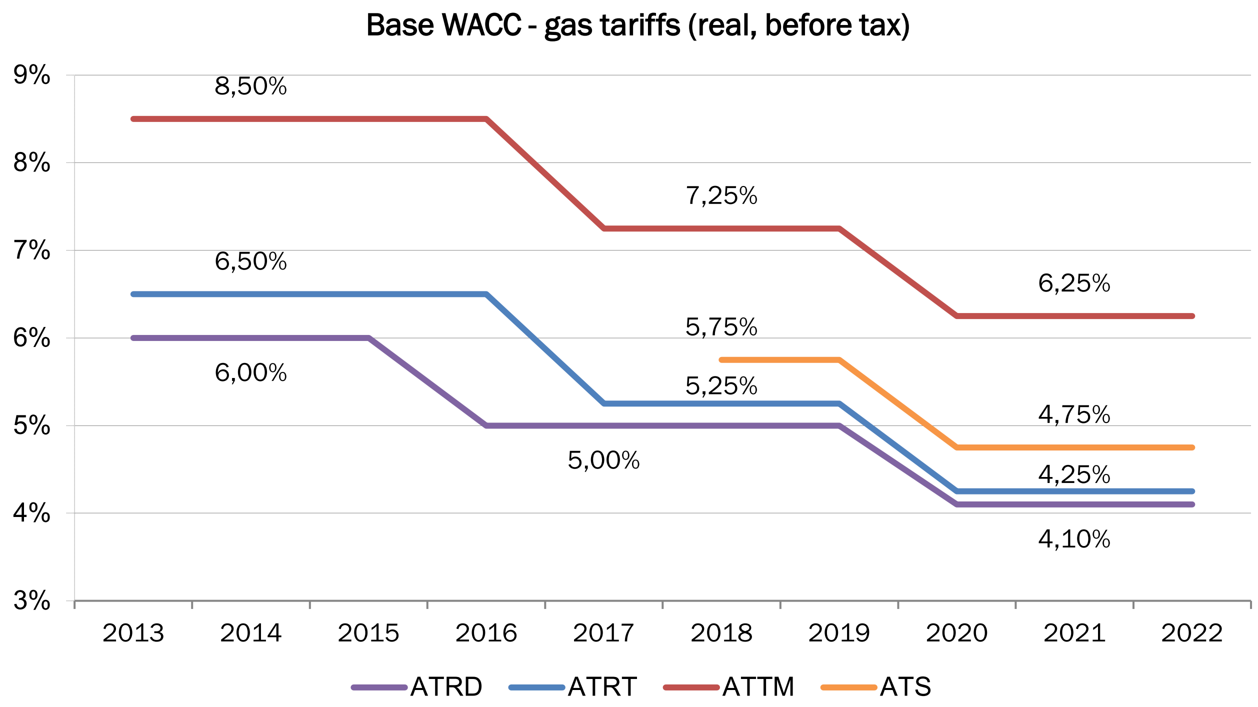
in M€	GRDF	GRTgaz	Teréga transmission	Storengy	Teréga storage	Géo-méthane
2012	14 217	6 882	1 010			
2013	14 306	7 045	1 109			
2014	14 314	7 309	1 171			
2015	14 226	7 579	1 194			
2016	14 162	7 978	1 322			
2017	14 361	8 223	1 328			
2018	14 629	8 278	1 372	3 526	1 182	189
2019	14 925	8 774	1 510	3 686	1 205	203
2020	15 138	8 724	1 553	3 580	1 194	200
2021	15 196	8 623	1 552	3 714	1 196	199
2022	16 398	9 175	1 697	3 974	1 248	207

The sharp rise in RABs in current euros in 2022 is due to the application of inflation of 6.2%. GRTgaz and Teréga have seen their RABs rise by much more than inflation as a result of the massive effort to strengthen the French gas transmission system between 2008 and 2019: development of interconnections, connection of LNG terminals, creation of the single market zone. Other RABs have risen in line with inflation.

At 1 January 2023, the sum of the RABs of gas infrastructure operators in mainland France (including regulated LNG terminal operators and excluding ELD gas companies) amounted to 34 billion euros.

5 Rate of return

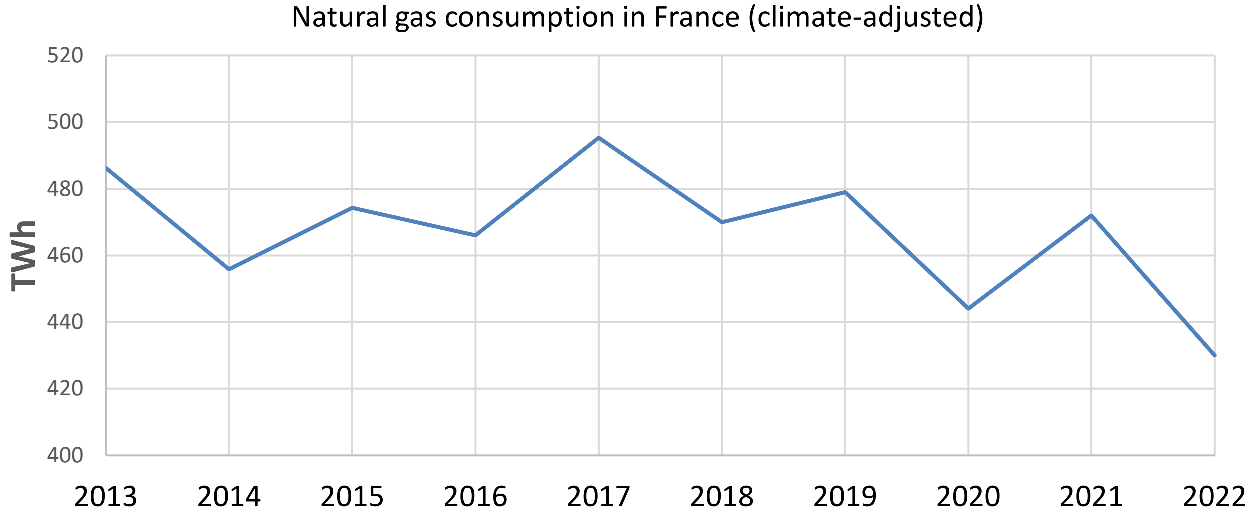
During previous tariff periods, the rate of return, or weighted average cost of capital (WACC), applied to the RAB aggregating the value of all the assets operated by a single operator. It was set for the entire duration of the tariff period and calculated on the basis of parameters derived from long-term data. In particular, the risk-free rate was calculated on the basis of long-term averages of long-maturity rates, in line with the long-life assets that make up the RAB.



Non-financial items

1. French consumption

Total domestic natural gas consumption in France in TWh (climate-adjusted):

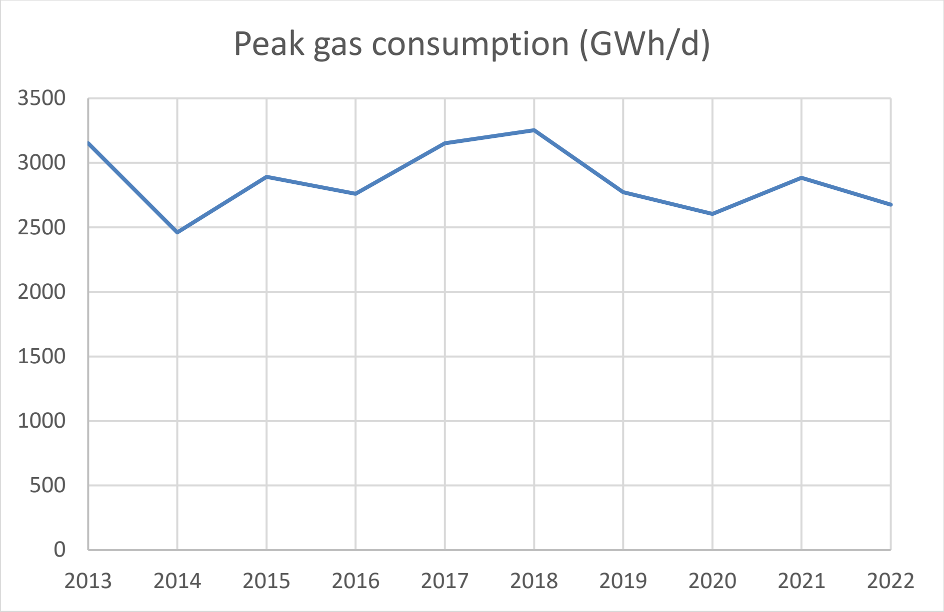


Year	Climate-adjusted consumption (TWh)	GRTgaz Area	Teréga Area
2013	486	469	31
2014	456	392	27
2015	474	423	28
2016	466	465	28
2017	495	467	28
2018	470	442	28
2019	479	451	28
2020	444	419	25
2021	472	444	28
2022	430	406	24

2. Peak gas France

Peak natural gas consumption in GWh/d.

In 2012, a peak consumption of 3670 GWh/d was observed on 8 February in climatic conditions corresponding to a risk of cold of 14%.



Year	Peak gas consumption (GWh/d)	GRTgaz Area	Teréga Area
2013	3152	2940	212
2014	2461	2274	187
2015	2893	2676	217
2016	2761	2588	173
2017	3153	2930	223
2018	3253	3042	211
2019	2773	2595	178
2020	2606	2465	140
2021	2884	2758	126
2022	2676	2519	157

3. Number of customers

Nb of customers	GDRF (millions)	GRTgaz	Teréga
2013	10.9	912	286
2014	10.9	948	328
2015	10.9	917	330
2016	10.9	914	331
2017	11.0	908	329
2018	11.1	908	335
2019	11.1	910	334
2020	11.2	896	341
2021	11.2	890	348
2021	11.1	879	354

4. Number of km of networks

	GDRF	GRTgaz	Teréga
2013	195 850	32 056	5 058
2014	196 940	32 153	5 065
2015	197 928	32 320	5 136
2016	198 886	32 456	5 134
2017	199 781	32 414	5 056
2018	200 715	32 548	5 080
2019	201 716	32 527	5 135
2020	202 759	32 519	5 127
2021	204 239	32 527	5 115
2021	205 809	32 618	5 099

5. Biomethane injection capacity (GWh/year)

Year	Distribution	Transmission	**Total**
2013	81		**81**
2014	133		**133**
2015	432	85	**517**
2016	599	85	**684**
2017	931	241	**1 172**
2018	1 515	373	**1 888**
2019	2 464	600	**3 064**
2020	4 264	902	**5 166**
2021	6 707	1 502	**8 209**
2022	9 234	2 207	**11 441**
2023	9 852	2 451	**12 303**

APPENDIX 2 : INCOME AND EXPENSE ITEMS COVERED BY THE CRCP AND COVERAGE RATES ENVISAGED AT THIS STAGE

		Coverage rate of the CRCP
Transmission revenue		100 %
Income from penalties received from clients exceeding capacity		100%
Normative "infrastructures" capital expenses		100 %
Differences in capital expenses "excluding infrastructure" due to inflation		100 %
Differences in net operating expenses due to the difference between forecast and actual inflation		100 %
Engine power expenses (excluding biomethane) and difference between income and expenses related to CO_2 quotas	Difference between tariff and forecast trajectory	100 %
	Difference between forecast and actual trajectory	80 %
Consumables expenses	Difference between tariff and forecast trajectory	100 %
	Difference between forecast and actual trajectory	80 %
Income from CCGT and CT connections		100 %
Income from biomethane unit connections		100%
Income from NGV station unit connections		100%
Income from services for third parties related to major land-use planning projects		100 %
Expenses relating to the H-B conversion		100 %
Costs and income generated by congestion management mechanisms		100%
Any costs related to, where applicable, remuneration of the consumers connected to the transmission network that have signed an interruptibility contract on the basis of Article L. 431-6-2 of the energy code		100 %
Inter-operator payment between GRTgaz and Teréga		100 %
Expenses and income associated with contracts with other regulated operators (in particular, storage operators)		100 %
Payment made by DSOs to TSOs for the portion of the biomethane injection charge collected from producers connected to the distribution network aimed at covering the OPEX associated with TSO backhaul (income)		100%
Inter-operator transfer between GRTgaz and Teréga related to the change in the $k_{national}$ factor		100 %
Costs of studies for large abandoned projects previously approved by CRE or other stranded costs addressed on a case-by-case basis for which CRE approved coverage		100%
Capital gain on assets disposal (building or land)		80 %
Bonuses and penalties resulting from the incentive regulation mechanisms		100 %
R&D expenses		100 % unused expenses at the end of the period

APPENDIX 3 : EVOLUTION OF SUBSCRIPTION REVENUES BY TYPE OF POINT (ILLUSTRATIVE SCENARIO)

Revenue from capacity subscriptions in current M€	2024	2025	2026	2027
IPs	358	376	337	215
PITTM	144	154	158	158
PITS	52	60	62	63
Exit to the regional network	466	493	488	475
Regional network revenues	1 210	1 252	1 233	1 199
Other revenue	34	33	32	32
Total	**2 263**	**2 367**	**2 310**	**2 142**

APPENDIX 4 : INFORMATION TO BE PUBLISHED UNDER THE TARIFF NETWORK CODE

<table>
<tr><th>Article</th><th>Informations à publier</th><th>Publication</th></tr>
<tr><td>29(a)
29(b)</td><td>a) for standard capacity products for firm capacity:
i. the reserve prices applicable until at least the end of the gas year after the annual yearly capacity auction;
ii. the multipliers and seasonal factors applied to reserve prices for non-yearly standard capacity products;
iii. the justification of the national regulatory authority for the level of multipliers;
iv. where seasonal factors are applied, the justification for their application;
b) for standard capacity products for interruptible capacity:
i. the reserve prices applicable until at least the end of the gas year after the annual yearly capacity auction;
ii. an assessment of the probability of interruption including:
1. the list of all types of standard capacity products for interruptible capacity offered including the respective probability of interruption and the level of discount applied;
2. the explanation of how the probability of interruption is calculated for each type of product referred to in point 1);
3. the historical or forecasted data, or both, used for the estimation of the probability of interruption referred to in point 2).</td><td>a) for standard capacity products for firm capacity:
i. the tariffs are indicated in section 5.2.2.2.5
ii. the applicable multipliers are indicated in section 5.2.2.2.4
iii. the justification is indicated in section 5.2.2.2.4
iv. N/A
b) for standard capacity products for interruptible capacity:
i. Standard capacity products for interruptible capacity and the level of discount applicable are indicated in section 5.2.3
ii. the details of the calculations of the probabilities of interruption, explained in section 5.2.3</td></tr>
<tr><td>30(1)(a)</td><td>Information on parameters used in the applied reference price methodology that are related to the technical characteristics of the transmission system, such as:
i. technical capacity at entry and exit points and associated assumptions;
ii. forecasted contracted capacity at entry and exit points and associated assumptions;
iii. the structural representation of the transmission network with an appropriate level of detail;
iv. additional technical information about the transmission network, such as the length and the diameter of pipelines and the power of compressor stations;</td><td>• The distances taken into account are indicated in Annex 6.
• The forecast subscribed capacities at the entry and exit points are given in section 4.8.2.
• The technical capacity data and all technical information are published on the websites of the TSOs based on ENTSOG's model.
○ GRTgaz
○ Teréga
• The structural representation of the transmission network is published on the TSOs' websites:
○ GRTgaz
○ Teréga</td></tr>
</table>

30(1)(b)	i. the allowed or target revenue, or both, of the transmission system operator; ii. the information related to changes in the revenue referred to in point i) from one year to the next year; iii. the following parameters: a. types of assets included in the regulated asset base and their aggregated value; b. the cost of capital and its calculation methodology; c. capital expenditures, including: i. methodologies to determine the initial value of the assets; ii. methodologies to re-evaluate the assets; iii. explanations of the evolution of the value of the assets; iv. depreciation periods and amounts per asset type; d. operational expenditures; e. incentive mechanisms and efficiency targets; f. inflation indices; iv. the transmission services revenue; a. the entry-exit split; b. the intra-system/cross-system split. v. the information related to the reconciliation of the regulatory account (the actually obtained revenue, the under- or over-recovery of the allowed revenue and the part thereof attributed to the CRCP, and the reconciliation period) vi. the intended use of the auction premium;	• The information related to capital expenditures, operating expenses and allowed revenue is indicated in section 4.7. • The information related to incentive mechanisms, the functioning of the CRCP, is indicated in section 3. • the entry-exit split between transmission services revenue is 34% (entries)/66%(exits), and is described in section 5.2.2.2.1 • the split in transmission services revenue between transit and domestic consumption is roughly 17% for transit and 83% for domestic consumption. • The information related to the intended use of the auction premium is indicated in section 3.3.1.2
30(1)(c)	i. where applied, non-transmission tariffs for non-transmission services ii. the reference prices and other prices applicable at points other than those referred to in Article 29.	The tariffs for non-transmission services and all the prices applicable at the different points are indicated in part 5.
30(2)	• explanations of the differences in the levels of tariffs between two tariff periods • a simplified tariff model	• The differences between the levels of tariffs between 2019 and the tariffs over the ATRT7 period are indicated in section 5.2.2.2.5. The explanations of these differences are developed in part 3, 4 and 5 • The simplified model is published on CRE's website (Appendix 7).

APPENDIX 5: COMPARISON WITH THE CAPACITY WEIGHTED DISTANCE METHOD OF THE TARIFF NETWORK CODE

Article 8 of the Tariff network code describes in detail a method for calculating reference prices at entry and exit points based on subscribed capacities, the distances travelled by the gas as weighting factors, and combinations of entry and exit points in relevant flow scenarios (capacity weighted distance reference price methodology (CWD)).

The code stipulates that the reference price calculation method used by each regulator must be compared with this CWD method. CRE presents here the grid that would result from the strict application of this method:

€/MWh/d/year	CWD Entries	CWD Exits
IP Virtualys	189.20	
IP Taisnières B	147.58	
IP Dunkerque	189.20	
IP Obergailbach	189.20	331.34
IP Oltingue	189.20	331.96
IP Pirineos	189.20	409.17
PITTM Dunkerque	179.52	
PITTM Montoir	179.52	
PITTM Fos	179.52	
Exit to regional network		97.63
PITS	17.04	22.15

The parameters of the reference price calculation method based on capacity and distance as weighting factors are close to those of the CRE method, the main difference with the CRE method being the use of a 50/50 ratio for the breakdown of revenue between entries and exits. CRE considers that a 50/50 split is not appropriate given the particular configuration of the French network.

Furthermore, the CWD method is intended to produce uniform unit costs (€/MWh/d/year/km) for the various users of the gas transmission system. However, in practice, where the same entry point can supply several exit points, this is not necessarily the case. Here, the unitary cost for France-Switzerland and France-Germany is €0.77/MWh/d/y/km, compared with €0.71/MWh/d/y/km for France-Spain, and €0.88/MWh/d/y/km for supplying national customers.

APPENDIX 6: LIST OF FLOW SCENARIOS

Appendix published on the CRE's website.

APPENDIX 7: SIMPLIFIED TARIFF MODEL

Appendix published on the CRE’s website.