RÉPUBLIQUE FRANÇAISE
Liberté Égalité Fraternité

CRE COMMISSION DE RÉGULATION DE L'ÉNERGIE

Deliberation no. 2024-22

Deliberation of the French Energy Regulatory Commission of 30 January 2024 on the decision on the tariff for the use of the natural gas transmission networks of GRTgaz and Teréga

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

The session was attended by: Emmanuelle WARGON, president, Anthony CELLIER, Ivan FAUCHEUX, Valérie PLAGNOL and Lova RINEL, Commissioners.

The provisions of articles L. 452-2 and L. 452-3 of the Energy Code give authority to the Energy Regulation Commission (CRE) to set the methodology for establishing tariffs for the use of natural gas transport networks. According to the provisions of article L. 452-3 of the Energy Code, CRE may make "*changes to the level and structure of tariffs that it considers justified, notably in light of analysis on the operators' accounts and the foreseeable evolution of operating and investment expenses".*

The ATRT8 tariff will take effect from 1 April 2024.

CRE adopts this deliberation after a broad consultation of the stakeholders. Between February and September 2023, CRE organised five thematic workshops open to the public, then a public consultation on the ATRT8 tariff[1] from 26 July 2023 to 9 October 2023. Thirty-six (36) responses were received and non-confidential responses are published on CRE's website. Following this consultation, CRE organised three round tables with suppliers and their associations, consumer associations, licensing authorities and local authorities on CRE's guidelines on gas distribution, transport and storage tariffs. Finally, CRE interviewed the managers of gas transport networks (GRT), GRTgaz and Teréga, on several occasions, as well as their shareholders.

This decision is notably based on the business plans sent by the transport network operators as well as on numerous exchanges with them, on the internal analyses of CRE, on reports from external auditors[2] and on the opinions expressed by stakeholders in response to the public consultation, during round tables, workshops or hearings.

In addition, in its decision, pursuant to the provisions of article L.452-3 of the Energy Code, CRE has taken into account the energy policy guidelines provided by the Minister of Energy Transition by letter of 2 November 2023. These guidelines are published on CRE's website at the same time as this deliberation.

In accordance with the provisions of the Tariff Network Code[3], CRE's public consultation of 26 July 2023 was sent to the Agency for the Cooperation of Energy Regulators (ACER), which issued the conclusions of its analysis on 8 December 2023. CRE took this analysis into account in its decision.

1. Main challenges of the next gas transmission tariff (ATRT8 tariff)

In addition to the objectives of simplicity, predictability and continuity pursued by CRE in general in its tariff decisions, the ATRT8 tariff meets the challenges of the 2024-2027 tariff period, but also prepares gas transmission networks for the longer-term problems of the gas system.

[1] Public consultation no. 2023-07 of 26 July 2023 relative to the next tariff for use of the natural gas transport networks of GRTgaz and Teréga
[2] An audit of the demand in terms of operating expenses of GRTgaz and Teréga for the period 2024-2027, as well as an audit of the demand for the rate of remuneration of the regulated assets of GRTgaz and Teréga, both published on the CRE website.
[3] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on the harmonisation of tariff structures for the transport of gas

a. Controlling the costs of GRTs

The upcoming tariff period will be marked by continuation of the downward trend in natural gas consumption already observed for several years and constituting an objective of the multi-year energy programme (PPE). This decline in consumption accelerated in 2022 due to the effect of high gas prices, the frugality of gas consumers and the shift of some gas consumers towards other forms of energy. In addition, many long-term subscriptions at the entry and exit points of the gas transmission network expire between 2024 and 2027, and should not be renewed in the same proportions, which will automatically lead to a reduction in the base on which TSOs collect their allowed revenues and, therefore, an increase in tariff terms.

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[4], shows that the size of the necessary infrastructure, especially in transport, should only decrease slightly. Thus, significant fixed costs will be covered by a smaller user base than today, leading to further increases in tariff terms.

This perspective has led CRE to make changes to the tariff regulatory framework to ensure the long-term economic sustainability of the gas system.

CRE will be particularly vigilant and selective in examining any new investment project submitted by the TSOs. CRE will ensure that these projects meet the priority objectives of safety, network integrity and biomethane integration. In order to achieve these objectives, the ATRT8 tariff takes into account the recent rise in rates observed in the markets. This makes it possible to preserve the financing capacity of operators.

In this context, controlling the loads of gas TSOs is a key challenge. The operating expense trajectories used to establish the ATRT8 tariff meet this challenge.

b. Injection of biomethane and development of renewable and low-carbon gases

The ATRT8 tariff gives operators the means to contribute to the energy transition, particularly with regard to the resources allocated to the reception of biomethane in networks as well as to research and development.

The current PPE provides for a decreasing trajectory of gas consumption, and a transformation of the energy mix, including, in particular, development of gas of renewable origin. The PPE has set a target of 14 to 22 TWh per year of biogas injected into the networks by 2028. The development observed in recent years, more than 10 TWh of renewable gas injection reached in early 2023, is expected to continue and TSOs will have to adapt their networks accordingly, which will require specific investments.

c. Good functioning of the wholesale gas market

The pricing of the gas transmission network and, more broadly, all the rules for access to this network, play a major role in proper functioning of the wholesale gas market. Since 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 network have changed profoundly as a result of the decline in European supplies of Russian gas and this change in flows should be sustainable. This deliberation takes into account the changes in tariff structure necessary in this context.

d. Ability to adapt to short- and long-term changes

In the short term, TSOs must be able to operate the transmission network by taking into account gas flows that evolve significantly. In the long term, they must also be able to consider the conversion of part of their assets to the transport of hydrogen or CO_2.

The ATRT8 tariff provides resources to meet these needs.

2. Tariff regulatory framework

The review of previous tariff periods, the feedback from the workshops and the public consultation showed that the incentive regulation framework is working well and only requires marginal improvements in order to take evolutions of the gas system into account. Consequently, CRE renews, for the ATRT8, the main incentive regulation mechanisms in force in the ATRT7, adjusting them when necessary, in particular the incentive regulation for controlling operating expenses and investment expenses, the incentive regulation on service quality and research and development, or the coverage after-the-fact of certain deviations via the CRCP.

The tariff period that is ending has notably shown that the tariff framework did, in fact, protect TSOs during the health crisis and the energy price crisis, while limiting the impact on customer bills.

For the ATRT8 period, CRE makes several changes to the tariff regulation framework for the ATRT7 period, made necessary by the context.

[4] https://www.cre.fr/documents/Publications/Rapports-thematiques/avenir-des-infrastructures-gazieres-aux-horizons-2030-et-2050-dans-un-contexte-d-atteinte-de-la-neutralite-carbone

CRE is changing the method of calculating the weighted average cost of capital (WACC) to take into account the increase in rates observed recently

CRE's method of determining the weighted average cost of capital is based on a WACC with a normative structure to ensure an appropriate return on capital invested. Until now, it was based on the average of the rates observed over the last ten years, reflecting the long lifespan of gas network infrastructures. This method, which has changed very little over three tariff periods, has made it possible to maintain the attractiveness of the energy infrastructure in France, while taking into account the downward trend in rates observed over the past 10 years.

After this long period of decline, interest rates have been rising rapidly for about a year. Faced with this new situation, CRE is changing the method of calculating the WACC to better account for the short-term dynamics of interest rates.

To determine the WACC applicable during the ATRT8 tariff, CRE retains:

- a rate determined according to the method used for the ATRT7 and previous tariffs, based on the analysis of long-term parameters, which shows a real rate of 3.7% before taxes (i.e. 4.9% nominal before taxes, from which is restated the average inflation of 1.2% observed over the last ten years);
- a rate based on taking into account more recent economic data which shows a real rate of 5.5% before taxes (i.e. 7.6% nominal before taxes, from which is restated the average forecast inflation of 2.0%[5] over the ATRT8 tariff period).

These rates are combined into a weighted rate that will apply during the ATRT8 period. This weighting is based on a normative distribution of the respective share of old assets and new assets in the upcoming tariff period for a gas operator, i.e. 80% of historical assets and 20% of new assets.

The weighted WACC is therefore a real rate of 4.1% before taxes, or a nominal rate of 5.4% before taxes from which inflation is restated.

The real WACC retained for the ATRT8 is down 0.15 points compared to that of the ATRT7. It takes into account:

- through its component based on long-term parameters, the financing costs of existing assets, with interest rates in markets that have remained low over a long period;
- through its component based on recent economic data, the rise in interest rates observed since 2022 and its consequences on the financing costs of new assets;
- a decline in asset *beta* from 0.50 to 0.47, to reflect the resilience of regulated activities compared to other sectors of the economy during the recent crises (Covid 19, gas crisis). In addition, the regulatory framework of the ATRT8 tariff is more protective for TSOs than that of the ATRT7 tariff. However, risks persist for the future of gas infrastructures, which justifies retaining a higher *beta* than that of electricity network tariffs.

CRE is preparing for the future by changing the framework for new assets

In its study on the future of gas infrastructures, CRE notes that the existing gas transmission network will remain necessary through 2050 (less than 10% of infrastructure could be decommissioned or converted to hydrogen) even in scenarios of significant decrease in consumption. This observation leads to setting a different pricing framework for new assets in order to accelerate their depreciation.

As such, CRE retains the following pricing framework for assets that will enter the regulated asset base (RAB) from 2024:

- new assets are recorded in the RAB at book value, to which the nominal WACC rate (i.e. containing inflation) set by CRE at 5.4% applies, as is the case, for example, for assets under the electricity transmission tariff;
- reduction of the depreciation periods of the new assets with long lifespans, i.e. the change from a depreciation period of new pipelines from 50 to 30 years.

The regulatory framework for assets entered into the RAB previously is not changed.

[5] Inflation restatement is obtained by the real WACC formula before corporate tax = (1 + nominal WACC before corporate tax) / (1 + inflation) – 1

CRE is changing the manner of annual evolution of the tariff

Coefficient k, which makes it possible to take into account the level of the CRCP observed each year, will now be limited to + or – 3%, instead of + or – 2% as previously. In addition, the annual evolution of the tariff will incorporate the difference between the realised inflation of the previous year and the expected inflation.

These changes aim to ensure a better match between the charges recorded and the tariff level, particularly in periods of energy price volatility or inflation.

3. Tariff Level

Charges to be covered

GRTgaz and Teréga have each made a request for tariff changes that present their estimated costs for the period 2024-2027. They report contending with the general increase in costs (inflation), including energy prices, as well as increasing obligations in terms of safety or reduction of greenhouse gas emissions.

Taking into account the elements of the tariff files sent to CRE by GRTgaz and Teréga would have led to a significant increase in the expenses to be covered, which correspond to the sum of net operating expenses and normative capital expenses. These would have totalled 2,559 M€/year over the ATRT8 period, compared to 2,089 M€ recorded in 2022 (or +22%).

In particular, these requests showed a significant increase in net operating expenses, while gas consumption is on a downward trend and the network is sufficiently sized overall.

At the end of its analyses and the additional exchanges it has had with operators since the public consultation of 26 July 2023, CRE considers that the increase in charges to be covered is less significant than that requested by the TSOs. In particular, it plans to limit the increase in net operating expenses of TSOs, while leaving operators the financial leeway to maintain a high level of security and to be a player in the energy transition. CRE is not modifying the investment trajectory presented by the TSOs but is not retaining the level of WACC requested by GRTgaz and Teréga.

As a result, the level of expenses to be covered[6] during the ATRT8 period totals, on average, 2,267 M€/year for all operators, an increase of 8% compared to the level achieved in 2022 of 2,089 M€.

Operating expenses

According to its analyses, CRE retains operating expense trajectories for GRTgaz and Teréga allowing them, in particular:

- to have the necessary means to fulfil all their missions and, in particular, to guarantee the industrial safety of their facilities, with maintenance of the level of expenditure achieved in the last tariff period;
- to have the necessary resources to continue the integration of biomethane into their networks, in line with the energy policy guidelines;
- to keep their information systems up to date, particularly with regard to cybersecurity;
- to perform R&D work on the safety, integrity and performance of the network, the integration of renewable gases and preparation of the network for structural changes related to the energy transition;
- to study the possibility of converting part of their assets to hydrogen (H_2) or carbon dioxide (CO_2).

Over the period 2024-2027, the level of the trajectory of net operating expenses excluding "system purchases" set by CRE for GRTgaz is controlled. Overall, the trajectory of GRTgaz's net operating expenses excluding "system purchases" is 2.8% higher than the level of 2022 expenditure, adjusted for inflation[7]. From 2025, it includes gains in efficiency of 1% per year on controllable charges (excluding staff costs). The increase is explained in particular by an increase in operating expenses for information systems (IS), which is partly offset by a decrease in IS investments.

Over the period 2024-2027, the trajectory of net operating expenses excluding "system purchases" set by CRE for Teréga is slightly lower than the level of 2022 expenses updated for inflation (- 0.6% over the period).

The average level of net operating expenses retained for the ATRT8 totals 928 M€/year for GRTgaz and 78 M€/year for Teréga (respectively 684 M€/year and 67 M€/year excluding "system purchases").

The trajectory of net operating expenses set by CRE for the ATRT8 tariff period corresponds to an overall budget. The TSOs will distribute this budget between the different types of charges, according to their management choices.

[6] Excluding CRCP and smoothing effect
[7] Taking into account a correction of the effect of changes in forecast expenses of a contract with another regulated operator

The ATRT8 tariff also provides for a rendez-vous clause to integrate any charges that could be related to implementation of the European Regulation to reduce methane emissions once adopted, as well as a rendez-vous clause related to external events that could result in an increase in operating expenses of more than 1%.

Capital Charges

CRE retains a real WACC of 4.1%, before taxes (i.e. 5.4% nominal before taxes).

CRE has not made any change to the investment trajectory presented by GRTgaz and Teréga. In the context of the structural decline in gas consumption, operators' capital expenditure will have to be brought under control. CRE will notably monitor control of these expenses at the time of annual approval of the TSOs' investments, as specified by the provisions of articles L. 134-3 and L. 431-6 of the Energy Code.

The average level of capital charges to be covered for the ATRT8 period is:

- 1,072 M€/year on average for GRTgaz;
- 188 M€/year on average for Teréga.

Finally, it is recalled that the "infrastructure" investments of the TSOs are covered by the tariff according to the completed work observed at 100% by means of the expense and revenue adjustment account (CRCP) and that the TSOs are protected from the evolution of inflation by the tariff.

For the ATRT8 period, the expenses to be covered, which correspond to the sum of operating expenses and capital expenses, total 2,000 M€/year for GRTgaz and 267 M€/year for Teréga.

Forecast subscriptions

CRE retains assumptions of subscriptions of transmission capacities close to the requests of GRTgaz and Teréga, but it makes changes concerning the expected subscriptions of certain interconnection points. Capacity subscriptions are down (in volume) by -5%/year on average at the points of the main network and -2%/year on average at the points of the GRTgaz regional network, and by -2%/year on average at the points of the main network and -3%/year on average at the points of the Teréga regional network, between 2023 and 2027. This significant decrease in subscription forecasts is due to the continued decline in gas demand and the end of certain long-term subscription commitments.

4. Tariff structure

The structure of the ATRT8 tariff is set so as to reflect the costs incurred by users, notably to avoid cross-subsidies between categories of users. The ATRT8 tariff meets the requirements of the Tariff network code and CRE has taken ACER's analysis into account in its development.

CRE used the same methodology as for ATRT7 to establish the ATRT8 tariff table, which notably provides that the unit costs of cross-border flows and food for domestic consumers are aligned. The flow scenarios have been adapted to take into account the end of long-term contracts, the reorganisation of flow patterns in Europe and the decrease in gas consumption.

CRE does not make any changes to the pricing structure of the regional transmission network.

5. Storage tariff term

Since reform of the regime for third-party access to the underground natural gas storage infrastructures, which took effect on 1 January 2018, the difference between the allowed revenue of storage operators and the revenues they receive directly, in particular through the commercialisation of their capacities at auction, is offset *via* the ATRT tariff, by a specific term called the storage tariff term. This storage tariff term now applies to non-transferable and non-interruptible customers connected to the gas transmission and public distribution networks, depending on their winter modulation.

The methods of calculating this storage tariff term remain unchanged compared to the ATRT7.

6. Transparency

CRE publishes on its website, in addition to this deliberation:

- the energy policy guidelines letter sent by the Minister of Energy Transition;
- the information to be published as part of the final tariff decision provided for in articles 29 and 30 of the Tariff Network Code: reserve price of capacities, parameters used in the method of calculating reference prices (in particular the justification of flow scenarios), financial information on the charges to be covered and their distribution, evolution of tariffs, etc.;
- the external audit of the request for operating expenses of GRTgaz and Teréga for the period 2024-2027;

- the external audit of the request for remuneration rates for regulated assets of the natural gas transmission system operators of GRTgaz and Teréga;
- non-confidential responses to the public consultation of 26 July 2023;
- a simplified tariff model;
- an English translation of the tariff deliberation.

The Energy Council, consulted by CRE on the draft decision, issued its opinion on 25 January 2024.

7. Allowed revenue and evolution of tariff terms

The total allowed revenue of the two TSOs (which corresponds to the sum of the charges to be covered and settlement of the CRCP) totals, on average, 2,250 M€ per year over the period 2024-2027.

Due to the cumulative effect of the increase in allowed revenue and the decrease in subscriptions, the average increase in the various tariff terms in 2024 is approximately +19% compared to the tariff in effect. The tariff terms will then change each year according to inflation, plus or minus a corrective term.

Key figures

Key figures 2024-2027 (in current €)		
	ATRT8	*2022 realised*
Operating expenses M€/year	1,007	869
GRTgaz	*928*	*797*
Teréga Transport	*78*	*72*
Capital charges M€/year	1 260	1220
GRTgaz	*1 072*	*1043*
Teréga Transport	*188*	*177*
WACC (real before tax)	4.1%	4.25%
of which historical rate	*3.7%*	*N/A*
of which short-term rate	*5.5%*	*N/A*
WACC (nominal before tax)	**5.4%**	**5.60%**
of which historical rate	*4.9%*	*N/A*
of which short-term rate	*7.6%*	*N/A*
Investments M€/year	581	512
GRTgaz	*459*	*405*
Teréga Transport	*121*	*107*

Tariff 2024			
Main Network		**(€/MWh/d/year)**	**Evolution vs. tariff 2023**
Entry	IP	130.63	23.6%
	PITTM	116.36	22.3%
Exit	Obergailbach	443.25	18.0%
	Oltingue	440.47	13.9%
	Pirineos	580.15	-1.2%
	Alveringem	52.17	24.0%
	Domestic	124.42	30.7%
Regional Network		**(€/MWh/d/year)**	**Evolution vs. tariff 2023**
Regional network transport	GRTgaz	96.38	14.3%
	Teréga	102.60	21.0%

	2024	**2025**	**2026**	**2 027**
Inflation assumptions[8]	2.5%	2.0%	2.0%	1.8%

[8] Excl. tobacco

CONTENT

1. CRE's Powers and tariff development process

1.1 CRE's powers

The provisions of article L. 134-2, 4° of the Energy Code empowers CRE to specify "the conditions of use of natural gas transmission networks [...], including the methodology for establishing tariffs for the use of these networks [...] and tariff changes [...]".

The provisions of articles L. 452-1, L. 452-2 and L. 452-3 of the Energy Code provide a framework for CRE's powers in terms of tariffs.

In particular, the provisions of article L. 452-1 provide that these tariffs "shall be established in a transparent and non-discriminatory manner in order to cover all the costs incurred by the transmission system operators [...], insofar as these costs correspond to those of effective operators. These costs take into account the characteristics of the service rendered and the costs related to this service, including the obligations set by law and regulations as well as costs resulting from the performance of public service missions and the contracts mentioned in I of article *L. 121-46*".

The provisions of article L. 452-2 state that CRE determines the methods used to establish the tariffs for using natural gas networks.

In addition, article L. 452-3 of the Energy Code provides that CRE deliberates on tariff changes "with, where appropriate, changes in the level and structure of tariffs that it considers justified, notably in light of the analysis of the accounting of operators and the foreseeable evolution of operating and investment expenses". The deliberation of CRE may provide for "a multi-year framework for the evolution of tariffs as well as appropriate incentives in the short or long term to encourage operators to improve their performance related, in particular, to the quality of service provided, the integration of the internal gas market, the security of supply and the search for gains in productivity".

Article L. 452-3 also provides that CRE "shall, in accordance with the procedures it determines, consult the players in the energy market".

By this deliberation, CRE defines the methodology for establishing the tariff for use of the GRTgaz and Teréga natural gas transmission networks, and sets the so-called "ATRT8" tariff.

1.2 Tariff Development Process

1.2.1 Consultation of stakeholders

Given the need for visibility of the interested parties and the complexity of the topics, CRE organised, between February and September 2023, five thematic workshops open to the public:

- the first, held on 22 February 2023, concerned the tariff structure of gas distribution tariffs. This workshop notably made it possible to present the evolutions foreseen by CRE concerning the introduction of a tariff term invoiced according to the throughput of users' meters and aimed at taking into account the development of back-up uses in distribution. This workshop was attended by 75 participants;
- the second, held on 4 May 2023, concerned the tariff structure of gas transmission tariffs. This workshop notably made it possible to present the changes foreseen by CRE concerning the tariff structure of the large transport network, in particular the tariffs applicable to interconnections. This workshop was attended by 70 participants;
- the third, held on 10 May 2023, concerned green gases. This workshop notably made it possible to present the changes foreseen by CRE concerning the pricing applicable to the injection of renewable and low-carbon gases into the networks. This workshop was attended by 85 participants;
- the fourth, held on 20 June 2023, focused on the future of French gas infrastructures and the possible adaptations of the tariff regulation framework to take into account the decrease in natural gas consumption. This workshop notably made it possible to present the evolutions foreseen by CRE concerning the depreciation chronicle of the Regulated Asset Base (RAB), to acknowledge inflation in the regulated asset base and possible incentives for the control of investments. This workshop was attended by 86 participants;
- finally, the fifth workshop, held on 13 September 2023, was devoted to GRDF's quality of service and made it possible to present the changes foreseen by CRE on various service quality indicators, including commissioning times, the quality of metering and complaint processing times. This workshop was attended by 61 participants.

At the end of these workshops, CRE organised a public consultation published in French and English, which took place from 23 July 2023 to 9 October 2023, and collected 36 responses.

Non-confidential responses to this consultation are published on CRE's website.

Following this public consultation, CRE organised three round tables with suppliers, consumer associations, and licensing and local authorities, respectively, to gather their comments on the guidelines presented in the public consultations on distribution, transport and storage tariffs and on the impact of these guidelines on users.

Finally, CRE interviewed the TSOs on several occasions, as well as their respective shareholders.

1.2.2 Energy policy guidelines

Pursuant to the provisions of article L. 452-3 of the Energy Code, CRE took into account the energy policy guidelines provided by the Minister of Energy Transition by letter of 2 November 2023. These guidelines include:

- the need to control costs in a context of reduced gas consumption by enhancing the selectiveness of future investments, which should focus on safety and the integration of renewable and low-carbon gases;
- the structure of tariffs for the use of natural gas transmission networks, in order to take into account the acceleration of the decline in methane gas consumption, or the reduction in the number of connected consumers;
- limiting communications from TSOs that would go against the necessary reduction in methane gas consumption;
- examination of the conversion of certain assets to other gases, in particular hydrogen and carbon dioxide;
- the integration of renewable and low-carbon gases, in particular for the connection and reinforcement of biomethane, and the injection of hydrogen residues into the networks;
- taking changes in gas flows into account for operation of the networks.

CRE has not received any energy policy guidelines from the Minister of the Economy.

To meet these challenges, the ATRT8 tariff provides, in particular, additional resources for the modelling of gas networks, specific budgets for studies on the conversion of certain assets to other gases, as well as the integration of renewable and low-carbon gases into the networks. CRE also introduces, for the ATRT8 period, evolution of the tariff framework to control the evolution of unit costs in the long term by accelerating the depreciation of the RAB for new assets.

1.2.3 Transparency

CRE is committed, as part of the tariff work, to ensuring transparency for all interested parties on the methods, tools and data it uses.

For development of the ATRT8 tariff, CRE published, in its public consultation, all the information stated in article 26 of Regulation (EU) 2017/460 (the "Tariff Network Code"), relating to the configuration of the transmission network, the methodology for determining the tariff terms and its comparison with the reference method of the Tariff Network Code. All of this data is summarised in the appendices.

In this deliberation, CRE publishes all the information stated in articles 29 and 30 of the Tariff Network Code and, in particular: the reserve prices of capacities, the parameters used in the method of calculating reference prices (in particular the justification of the flow scenarios), the financial information on the charges to be covered and their distribution, the evolution of tariffs, etc. This information is summarised in Appendix 7 of the deliberation.

In addition, CRE published the external studies conducted in the framework of development of the ATRT8 tariff. These studies cover the following topics:

- an audit of demand in terms of operating expenses of GRTgaz and Teréga for the period 2024-2027[9];
- an audit of the request for remuneration rates for the regulated assets of GRTgaz and Teréga[10].

Finally, CRE publishes a simplified tariff model on its website.

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[9] Audit of demand in terms of operating expenses of GRTgaz and Teréga for the period 2024-2027
[10] Audit of the request for remuneration rates for regulated assets of the natural gas transmission network operators

1.2.4 Analysis of the ACER

In accordance with the provisions of the Tariff Network Code, the ACER rendered the conclusions of its analysis on CRE's public consultation on 8 December 2023. The report is available on ACER's website[11].

2. Tariff regulatory framework

2.1 Assessment and challenges of the tariff regulation framework

Stable in its main principles for more than 10 years, the tariff framework for gas and electricity networks and infrastructures has three main objectives:

- encourage infrastructure managers to control their costs to limit the impact of infrastructure tariffs on the end consumer;
- enable operators to finance the necessary infrastructure investments;
- aim for a high level of quality of service, security and continuity of routing.

To do this, it relies on financial mechanisms to encourage infrastructure managers to seek efficiency over time. Thus, a four-year tariff period and the principle of multi-year financial incentives on costs and quality of service were introduced. The regulatory framework leaves wide freedom in the management of each of the infrastructure operators, allowing each of them to seek the most relevant performance improvements.

CRE draws up a positive assessment of this framework, which has made it possible to control costs over time while improving the quality of service. This framework has also been very resilient in the face of two major crises, the health crisis[12] and the energy price crisis, by giving operators the means to ensure business continuity under good conditions.

Most respondents to the public consultation share CRE's conclusions on the positive outcome of the regulatory framework for the ATRT7 period, which made it possible to effectively control costs for the benefit of the end customer, make the necessary investments and operate gas infrastructures under good conditions in an unprecedented context of supply crisis. Network operators have asked to be more protected from changes in economic conditions in view of recent events (especially with regard to energy prices).

Given this assessment (see detailed assessment published in Appendix 1 of the public consultation), CRE decided, for the ATRT8, to renew most of the regulatory framework provided for by the ATRT7, while changing a few mechanisms.

2.2 Main principles of the tariff framework

Development of the ATRT8 tariff is based on definition, for the ATRT8 tariff period, of an allowed revenue trajectory for each of the TSOs and of forecast subscription capacities on their respective networks.

The ATRT8 tariff also sets a regulatory framework in order to limit the financial risk of TSOs and/or users for certain predefined expense or product items, through an expense and revenue accrual account (CRCP) and, on the other hand, to encourage TSOs to improve their performance through incentive mechanisms.

Taking all these elements into account makes it possible to establish the rate applicable from 1 April 2024 as well as its terms of annual evolution.

2.2.1 Determination of the allowed revenue of TSOs

In this deliberation, on the basis of the tariff file sent by the operators and its own analyses, CRE sets the forecast allowed revenue of each TSO for the period 2024-2027. Allowed revenue covers the costs of operators on a calendar basis to the extent that these correspond to those of an efficient operator.

[11] https://www.acer.europa.eu/Publications/2023_Analysis_Report_Tariffs_France.pdf
[12] Deliberation of 25 March 2021 involving communication on the effects of the COVID-19 crisis for network operators for the year 2020

This forecast allowed revenue of the TSOs consists of the forecast net operating expenses (CNE), the forecast normative capital expenses (CCN), settlement of the balance of the expense and income adjustment account (CRCP), the forecast inter-operator payment (INT) between GRTgaz and Teréga and a smoothing term (LIS):

RA = CNE + CCN + CRCP + INT + LIS

With:

- RA: projected allowed revenue over the period;
- CNE: projected net operating expenses over the period (see 2.2.1.1);
- CCN: projected normative capital costs over the period (see 2.2.1.2);
- CRCP: settlement of the CRCP balance (see 2.2.3);
- INT: estimated inter-operator payment financial flow resulting from the equalisation of the tariff terms of the main network (see 2.3.4);
- LIS: smoothing term resulting from the pricing changes defined in section 2.3.4).

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

2.2.1.1 Net operating expenses

Net operating expenses (CNE) are defined as gross operating expenses from which operating income is deducted (capitalised production and non-tariff income in particular).

Gross operating expenses consist mainly of energy expenses, network operation and maintenance expenses, external consumption, personnel expenses and taxes.

The level of net operating expenses retained is determined from all the costs necessary for the activity of the TSOs insofar as, pursuant to article L. 452-1 of the Energy Code, these costs correspond to those of an efficient network operator.

2.2.1.2 Normative capital charges

Normative capital charges (CCN) include the remuneration and depreciation of fixed capital. The calculation of these two components is based on the valuation and evolution of assets operated by operators – the regulated asset base (RAB) – and assets under construction (AuC), i.e. investments made that have not yet given rise to the commissioning of assets.

The CCN corresponds to the sum of the depreciation of the constituent assets of the RAB and the return on fixed capital. The latter corresponds to the product of the value of the RAB by the weighted average cost of capital (WACC) and the product of the value of the AuCs by the cost of debt.

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

2.2.2 Cost of capital and investment coverage

2.2.2.1 Limit the risk of an excessive increase in the unit cost of routing for future network users

In its study on the Future of Gas Infrastructures[13], CRE shows that despite the decline in consumption, the sizing of the French gas infrastructure is not expected to change significantly by 2050:

- gas transmission and distribution networks will remain largely necessary. Assets will nevertheless be able to be released, in proportions that will remain limited;
- a significant share of storage capacity will still be needed to meet the need for seasonal modulation of consumption.

The networks could also continue to develop to support the development of renewable and low-carbon gases, and will have to adapt to the emergence of back-up use. Thus, the charges of gas operators are not expected to decrease in the same proportions or at the same rate as gas consumption by 2050, thus leading to an increase in the unit cost of transport ("scissor" effect).

The lever identified to limit the "scissor" effect is to adapt the distribution of capital charges over time, with the objective of increasing them in the shorter term in order to reduce them in the longer term, in line with the anticipated evolution of gas consumption. This avoids having tomorrow's consumer bear today's burdens.

[13] CRE, "Future of gas infrastructure in 2030 and 2050, in a context of achieving carbon neutrality", 2023

In the public consultation, CRE presented three options to allow this reallocation of capital charges over time:

1. end the inflation indexation of the RAB by moving to remuneration of the RAB at a nominal WACC and no longer real;
2. adapt the rate of depreciation (switch to declining balance depreciation, higher at the beginning and then reduced), so that depreciation costs are more consistent with the decrease in gas consumption;
3. reduce the depreciation period of certain assets.

Even if the risk of margin squeeze is well identified, most respondents do not fully share the guidelines presented by CRE. Many respondents fear implementation that is too abrupt at a time when the tariff is already rising sharply. Others consider this development impossible to deploy in such short timeframes and are concerned about their economic neutrality. Finally, a gradual implementation was mentioned by various respondents.

CRE takes into account feedback from the public consultation, according to which not all the measures foreseen within the public consultation should be implemented. In fact, CRE considers that implementation of these measures applied to all the assets of the RAB of TSOs cannot be foreseen due to escalation in the tariff increase that it would generate.

Consequently, CRE decides, with the objective of continuity of the regulatory framework, to partially retain two of the measures presented by applying them <u>only to new assets that will enter the RAB from 1 January 2024</u>:

- New assets are no longer revalued against inflation and are, in return, subjected to a nominal WACC (i.e. including inflation);
- The new "pipelines and connections" type assets are depreciated over 30 years instead of 50 years (these assets are the network equipment for which the depreciation period is the longest).

These measures each have effects of less than 1% on the tariff increase.

Moreover, as foreseen in the public consultation, CRE does not accept Teréga's request to introduce an increase in operating expenses attributable to depreciated assets. In fact, this mechanism could introduce an overcompensation of assets, without providing a certain financial benefit for the tariff; the possible savings of capital charges allowed by this measure are indeed uncertain.

2.2.2.2 Methods for calculating the regulated asset base (RAB)

The RAB represents the sum of tangible and intangible fixed assets in the assets of the operator (valued on 1 January of each year):

- the RAB increases when an asset is put into service;
- the RAB decreases with the depreciation of assets, or if an asset is scrapped or sold.

For so-called "historical" assets entered in the RAB through 1 January 2023

For the ATRT8 tariff, CRE renews the manner of calculating the RAB in effect for the ATRT7 tariff.

The value of the RAB is established on the basis of a methodology of the "current economic costs" type, the essential principles of which were adopted by the Special Commission established by article 81 of the Amending Finance Law of 28 December 2001, responsible for setting the sale price, by the State, of its natural gas transmission networks.

Since 2006, the contractual date of entry of assets into the RAB is set at 1 January of the year following their commissioning. The gross values of the assets are restated for the revaluation differences authorised in 1976 and the subsidies received for making these investments.

Once included in the RAB, the assets are revalued on 1 January of each year for inflation from July to July. For this reason, CRE uses a real WACC that does not include inflation. Since 2016, the revaluation index used is the 1763852 index of consumer prices excluding tobacco, for all households residing in France.

Assets are depreciated on a straight-line basis based on their economic life. The land is taken into account at its revalued historical value without depreciation.

The lifespans used by CRE for the main asset classes are as follows:

Category of assets	Normal lifespan
Pipes and connections	50 years
Delivery stations, expansion and metering	30 years
Compression	30 years
Other related installations	10 years
Buildings	30 years

For so-called "new assets" entered the RAB from 1 January 2024

The value of the RAB is calculated from the net book value of the assets in service. The contractual date of entry of assets into the RAB is 1 January of the year following their commissioning.

Assets are depreciated on a straight-line basis based on their economic life. The land is taken into account at its revalued historical value without depreciation. The gross values of assets are restated for the subsidies received for realising these investments.

The lifespans used by CRE for the main asset classes are as follows:

Category of assets	Normal lifespan
Pipes and connections	**30 years**
Delivery stations, expansion and metering	30 years
Compression	30 years
Other related installations	10 years
Buildings	30 years

CRE applies a nominal WACC for assets entering the RAB from 1 January 2024.

2.2.2.3 Methods for calculating the weighted average cost of capital (WACC)

The method used to set the rate of return on assets is based on the WACC with a normative financial structure. In fact, the level of remuneration of the TSO must, on one hand, allow it to finance interest charges on its debt and, on the other hand, provide its shareholders with a return on equity comparable to that which they could obtain for investments with comparable levels of risk. This cost of equity is estimated on the basis of the methodology known as the "financial asset valuation model" (MEDAF).

In the public consultation of 26 July 2023, CRE foresaw changing the method of calculating the WACC to take recent rate increases into account.

To determine the WACC applicable during the ATRT8 tariff, CRE plans to retain:

- a rate determined according to the method used for the ATRT7 and previous tariffs, based on the analysis of long-term observed parameters (e.g. 10-year average of risk-free rates);
- a rate based on taking more recent economic data into account.

CRE specified in its public consultation that these rates could be applied respectively to old and new assets, or combined in a weighted rate.

Concerning determination of the level of the WACC, network operators and their shareholders are generally in favour of adjusting the WACC method to take the recent increase in interest rates into account, while suppliers and consumer associations are against it, arguing that the stability of the method should prevail.

On the other hand, most respondents are against the introduction of a double rate and support a weighted rate.

Given the feedback to the public consultation, CRE decided, for the ATRT8 tariff period, to change the method of calculating the weighted average cost of capital by weighting two rates, one based on an analysis of long-term parameters (as in ATRT7) and the other taking more recent economic data into account.

This weighting is based on a normative distribution of the respective share of old assets and new assets in the ATRT8 tariff period for a gas operator.

2.2.2.4 Terms of remuneration of assets under construction

In the public consultation of 26 July 2023, CRE indicated that it was not in favour of remuneration for AuCs at the WACC, as requested by some operators, as this would reduce the strong incentive for operators to put assets into service as soon as possible.

CRE renews the principle of remuneration of assets under construction (AuC) at the cost of nominal debt before taxes, in line with the methodology generally used for interim interest.

The amount of these AuCs is equal to the average, for each year of application of the tariff, between their estimated level on 1 January and that on 31 December, taking into account capital expenditure and commissioning of assets done during the year.

2.2.2.5 Treatment of assets removed from inventory

2.2.2.5.1 Treatment of stranded costs

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

Stranded costs are treated as follows, upon presentation of the files by the operators:

- recurring or foreseeable stranded costs are subject to a tariff trajectory on the basis of an annual envelope set in this deliberation;
- the costs of studies without follow-up for major projects that have been the subject of prior approval by CRE are covered by the tariff via the CRCP;
- the coverage of other stranded costs is examined by CRE on a case-by-case basis, on the basis of substantiated cases submitted by the TSOs.

The costs to be covered, if any, by the tariffs are taken into account up to their book value minus any sale proceeds.

2.2.2.5.2 Treatment of transferred assets

When an asset is sold by an operator, it leaves its assets, leaves the RAB and ceases, in fact, to generate capital charges (depreciation and remuneration). This sale may, if applicable, generate a capital gain for the operator, equal to the difference between the sale proceeds and the net book value.

In the tariff framework provided for in the ATRT7 tariff, in the case of a transfer of real estate assets or land:

- if the disposal gives rise to an accounting gain, 80% of the net proceeds from the disposal of the net book value of the transferred asset are included in the CRCP so as to have network users benefit from most of the gains from the resale of these assets, insofar as these users have incurred the acquisition costs (the allowed revenue of the operators covering the annual depreciation and remuneration of the RAB assets), while preserving an incentive for the operator to maximise this gain. The latter retains the remaining 20% of the gain;
- a sale resulting in a book loss will be subject to examination by CRE, on the basis of detailed documentation submitted by the operator.

In its public consultation, CRE foresaw renewing the regulatory framework for real estate assets and land sold, as specified in ATRT7. Inclusion in the tariff of gains from disposal is, in fact, justified, considering that the tariff participated in financing the assets concerned. The majority of stakeholders are in favour of this renewal.

Consequently, CRE decides to renew this regulatory framework for real estate assets and land sold for the ATRT8 period.

2.2.2.5.3 Case of assets converted to hydrogen

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

The conversion of an asset of the gas transmission network to hydrogen assumes the removal of this asset from the RAB of the operator that operates it, and its transfer to another operator (or another asset base if it is the same operator, regardless of whether the hydrogen transport activity is regulated). This raises the question of the sale price of the assets concerned, and the sharing of any capital gains between the operator and the users.

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

The ATRT7 tariff did not provide a specific regulatory framework for assets that would be sold for conversion to hydrogen.

In the absence of a European framework in effect, CRE foresaw, in its public consultation, dealing with assets sold with a view to conversion to hydrogen on a case-by-case basis, relying on substantiated dossiers presented by the TSOs. CRE will be careful to ensure that the transfer price is set in such a way as to avoid cross-subsidisation between users of the gas and hydrogen networks, and that the sharing of any added value between TSOs and users is relevant. In the event that future hydrogen transport networks are regulated, CRE will also ensure that their future hydrogen users do not have to pay costs already covered by previous gas users.

The vast majority of respondents are in favour of the guidelines presented by CRE in the public consultation. Some respondents mention, in particular, the need to avoid cross-subsidies.

Given the absence of a European framework and the lack of visibility, on the date of this deliberation, on the economic models of the hydrogen sector, CRE decides to deal with the assets sold for conversion to hydrogen on a case-by-case basis, relying on the detailed files submitted by the TSOs.

2.2.3 Adjustment account for expenses and income (CRCP)

Calculation and settlement

The level of the ATRT tariff is set by CRE based on assumptions about the estimated level of expenses and revenues of each operator. An *a posteriori* adjustment mechanism, the expense and income adjustment account (CRCP), has been introduced in order to take all or part of the differences between the expenses and income actually recorded and the projected expenses and income, for predefined items. Thus, the CRCP protects operators from the variation of certain cost or revenue items by offsetting certain deficits, and also protects the consumer by allowing the retrocession of certain surpluses. It is also used for the payment of financial incentives resulting from the application of incentive regulation mechanisms, calculated on the basis of the observed results.

Calculated on 31 December of each year N, the balance of the CRCP is cleared, within the limit of an annual tariff change associated with this clearance. This clearance limit was +/- 2% during previous tariff periods, for most electricity and gas network tariffs. It provided good visibility to market participants on the price trajectory during the four-year tariff period and ran smoothly for more than 10 years.

However, the gas crisis at the end of the 2019-2023 tariff period led to a high CRCP for some operators, particularly linked to rising energy prices, inflation and lower gas consumption. This observation led gas operators to request revision of the settlement procedures during the annual changes.

A majority of respondents to the public consultation, including infrastructure operators, are in favour of adjusting the CRCP clearance ceiling to +/- 3% due to the high uncertainty on certain expense items covered by the CRCP (in particular related to energy expenses and underwriting assumptions in a context of the end of long-term contracts). In view of the responses to the public consultation, CRE decides to increase the limit of an annual tariff evolution associated with clearance of the CRCP to +/-3%. This new clearance limit makes it possible to reconcile the objectives of maintaining reasonable tariff stability during the tariff period and taking into account a more volatile economic situation, in particular concerning energy prices.

In the event that this clearance limit is reached and does not permit full clearance of the CRCP balance in the tariff evolution of year N+1, the balance not cleared during year N+1 is carried over to year N+2. In addition, the CRCP balance recorded at the end of the tariff period is taken into account when establishing the allowed revenue for the following period.

Financial neutrality of the CRCP system

In order to ensure the financial neutrality of the system, the CRCP balance on 1 January of year N+1 is obtained by updating the CRCP balance on 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 projected CRCP balance at the end of the period, several operators have requested a change in this parameter. GRDF requested that the discount rate correspond to the nominal WACC before taxes or the nominal cost of the debt, as it considers that it must incur financing costs pending settlement of the CRCP. Teréga requested a discount rate of 3.30%, incorporating a risk-free rate and a "comfort premium", which is a specific adjustment to the yield on government bonds.

CRE recalls that the refund of the CRCP balance is always guaranteed, regardless of its level. In addition, it is returned to the operator in a relatively short term. Thus, the level of long-term risk included in the level of the WACC or of the cost of debt is not relevant for updating the CRCP balance. Thus, CRE considers that the risk-free rate remains the relevant parameter for updating the CRCP balance.

Nevertheless, CRE foresaw, in its public consultation, retaining the risk-free rate applied to new assets to update the balance of the CRCP, in line with the new framework for the remuneration of assets (see section 2.2.2.3) and the pace of clearance of the CRCP. The new method of determining the WACC takes into account a risk-free rate based on historical parameters and a risk-free rate on short-term data that apply, respectively, to historical assets and new assets.

Some of the respondents to the public consultation, including suppliers and infrastructure operators, are in favour of what CRE foresaw in the public consultation, i.e. updating of the CRCP at the short-term risk-free rate.

Some actors (mainly infrastructure operators) are in favour of remuneration of the CRCP at the WACC, in order to compensate for the financing costs pending clearance of the CRCP balance.

Other contributors ask to retain remuneration of the CRCP at the cost of the debt, in order to offset the cost of debt for the TSOs that can use this financial leverage pending clearance of the balance of the CRCP.

CRE maintains its analyses presented in the public consultation, and decides to update the CRCP balance at the risk-free rate applied to new assets during the ATRT8 tariff period, i.e. a rate of 3.8%.

Flow of compensation

To ensure the balance between the allowed revenue and the tariff revenue of each TSO, the ATRT7 tariff provided for a flow of compensation between GRTgaz and Teréga under the annual national evolution of the tariff terms of the main network.

In fact, as part of the annual evolution of the ATRT7 tariff, a $k_{national}$ coefficient was calculated to set the annual evolution of the tariff terms of the main network (see section 2.3.4). It results in an opposite revenue gap between GRTgaz and Teréga. This difference is transferred between the TSOs.

CRE decides to maintain the principle of this compensation flow between the two operators for the ATRT8 period. The details of its calculation are specified in paragraph 2.3.4 of this deliberation.

2.3 Tariff Calendar

2.3.1 A tariff period of four years

The ATRT7 tariff has been set for a period of about four years. In the public consultation, CRE foresaw maintaining this duration for the ATRT8 tariff.

In their responses to the consultation of 26 July 2023, market participants expressed their support for maintaining this duration of about 4 years, considering, like CRE, that it offers the market visibility on the evolution of infrastructure tariffs and that it gives operators the time necessary to undertake productivity efforts.

The ATRT8 tariff applies for a period of approximately 4 years, starting from 1 April 2024. It aims to cover expenses for calendar years 2024 to 2027. It evolves annually, on 1 April of each year, in the manner described in 2.3.3 of this deliberation.

2.3.2 Rendez-vous clauses

Rendez-vous clause at mid-tariff period

The ATRT8 tariff provides, as was the case for the previous tariff, a rendez-vous clause which may be activated by each TSO after two years.

Thus, the possible consequences of new legislative or regulatory provisions or a judicial or quasi-judicial decision may give rise to review of the tariff trajectory for the last two years of the tariff period (2026 and 2027), if the level of net operating expenses retained in the ATRT8 tariff is changed by at least 1%.

Rendez-vous clause regarding the impact of the future regulation on the reduction of methane emissions in the energy sector

The ATRT8 tariff also provides for a rendez-vous clause to take into account the additional charges that could result from the future regulation on the reduction of methane emissions in the energy sector. In view of the uncertainties that remain on the nature of the measures that will be imposed on the network operators and the resulting costs, CRE decides not to set a cost trajectory *a priori* on this item. The majority of respondents to the public consultation expressed this view. Each network operator may, once the methane emission reduction regulation has been published, request a review of its net operating cost trajectory to take into account the new costs directly resulting from this regulation. The Network Manager will submit a duly substantiated file to CRE. If necessary, CRE may also provide incentive regulation schemes dedicated to these measures.

2.3.3 Calendar of changes in tariff terms

The ATRT8 tariff terms apply from 1 April 2024 and will be revised annually according to the rules below:

- the IP tariff terms will change on 1 October of each year, with a first movement of these terms on 1 October of 2024. The tariff terms in effect at the IPs since 1 October 2023 will continue to apply between 1 April 2024 and 30 September 2024;
- the terms of biomethane injection[14] under the conditions provided for by the ATRD7. The biomethane injection tariff terms in force since 1 April 2023 will continue to apply between 1 April 2024 and 30 June 2024;
- the other tariff terms of the grid will change on 1 April of each year.

This schedule makes it possible, on one hand, to maintain consistency between the transport, LNG terminals and storage schedules and, on the other hand, to meet the constraint imposed by the Tariff network code to have, upstream of the annual interconnection capacity auctions (IP), the level of tariff terms that will apply from October N to October N+1. It also makes it possible to maintain a coherent level of tariff terms related to the injection of biomethane for all sites, whether they are connected to the transmission network or to the distribution network.

The majority of stakeholders that responded to the public consultation are in favour of what CRE foresaw in the public consultation. These stakeholders consider that this offers satisfactory visibility to market participants and guarantees proper functioning of the auctions.

2.3.4 Annual evolution of the level of tariff terms

The ATRT8 tariff implements tariff principles that allow a stable distribution of costs between the different categories of network users. In particular, to preserve, during the tariff period, the balance between the costs of the main network borne by the users performing transit, on one hand, and by the users feeding the national consumption on the other hand, the annual evolution must be identical for all the tariff terms of the main network.

However, as the charges and revenues of each of the operators may change for reasons specific to each network, the balance of the CRCP of GRTgaz and Teréga will be different at the end of the year.

Consequently, in the ATRT8 tariff, the calculation of the CRCP of each operator will result in a coefficient k_{GRTgaz} for GRTgaz and $k_{Teréga}$ for Teréga. The terms of the main network will change each year by the same national coefficient, called "$k_{national}$", corresponding to the weighted average of the capacity subscription receipts of the coefficients k_{GRTgaz} uncapped and $k_{Teréga}$ uncapped. The terms of the GRTgaz regional network will change by the k_{GRTgaz} coefficient, and those of the Teréga regional network will change by the $k_{Teréga}$ coefficient.

Finally, the ATRT8 tariff provides for an inter-operator flow resulting from equalisation of the tariff terms of the main network and making it possible to ensure the appropriateness between the charges and the revenues associated with the main network of the two operators (by compensating for the differences in revenues of the year concerned resulting from application of an average $k_{national}$ coefficient on the terms of the main network).

As was the case for the ATRT7 tariff, in its public consultation, CRE foresaw an annual and smoothed mechanical evolution of the ATRT8 tariff according to principles similar to those of the previous tariff period.

[14] Or of renewable and low-carbon gas, as will be defined in the ATRD7 deliberation of GRDF

Taking into account the responses to the public consultation and to respond to operators' requests to improve the pace of clearance of the CRCP in a more uncertain economic context, CRE retains three developments:

- to better take into account the effect of inflation, the annual tariff update for year N will take into account the correction of the inflation gap for year N-1 between the forecast of the draft finance law (PLF) and the level realised (or else the best estimate available when calculating the annual tariff update, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852));
- The $k_{national}$ is now calculated as the average of the uncapped $k_{GRTgaz}$and the uncapped $k_{Teréga}$ weighted by the capacity subscription revenues on the main network of each operator. During the previous tariff period, the $k_{national}$ was calculated as the weighted average of the $k_{GRTgaz,}$ and $k_{Teréga}$ previously capped;
- the ceiling of the clearance factors $k_{national,}$ k_{GRTgaz} and $k_{Teréga}$ is set at +/- 3% against +/- 2% during the ATRT7 tariff period as indicated in section 2.3.4.

The ATRT8 tariff will change annually, from 2025, on 1 April of each year, according to the following principles:

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

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

  Where:

  - $Z_{national}$ is the variation in the tariff schedule on 1 April of year N, expressed as a percentage and rounded to the nearest 0.01%;
  - IPC: the forecast rate of inflation excluding tobacco for year N taken into account in the draft finance law for year N, to which is added the difference between the real inflation for year N-1 as calculated by the INSEE (or else the best available forecast, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852)) and the forecast rate of inflation excluding tobacco for year N-1 taken into account in the draft finance law for year N-1;
  - $k_{national}$ is the evolution of the tariff schedule, as a percentage, capped at +/-3%, corresponding to the weighted average of the non-capped coefficients k_{GRTgaz} and $k_{Teréga}$ for capacity subscriptions on the main network.

  As an exception, the evolution of the terms relating to IPs applies from 1 October of each year.

- for the tariff terms of the GRTgaz regional network in effect on 31 March of year N; by the following percentage variation:

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

  Where:

  - Z_{GRTgaz} is the variation in the tariff schedule on 1 April of year N, expressed as a percentage and rounded to the nearest 0.01%;
  - IPC: the forecast rate of inflation excluding tobacco for year N taken into account in the draft finance law for year N, to which is added the difference between the real inflation for year N-1 as calculated by the INSEE (or else the best available forecast, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852)) and the forecast rate of inflation excluding tobacco for year N-1 taken into account in the draft finance law for year N-1;
  - k_{GRTgaz} is the evolution of the tariff schedule, as a percentage, capped at +/-3%, mainly resulting from clearance of the balance of the expense and income adjustment account (CRCP) of GRTgaz.

- for the tariff terms of the Teréga regional network in effect on 31 March of year N, the following percentage variation:

  $Z_{Teréga} = IPC + k_{Teréga}$
  Where:

  - $Z_{Teréga}$ is the variation in the tariff schedule on 1 April of year N, expressed as a percentage and rounded to the nearest 0.01%;
  - IPC: the forecast rate of inflation excluding tobacco for year N taken into account in the draft finance law for year N, to which is added the difference between the real inflation for year N-1 as calculated by the INSEE (or else the best available forecast, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852)) and the forecast rate of inflation excluding tobacco for year N-1 taken into account in the draft finance law for year N-1;
  - $k_{Teréga}$ is the evolution of the tariff schedule, as a percentage, capped at +/-3%, mainly resulting from clearance of the balance of the expense and income adjustment account (CRCP) of Teréga.

As an exception, these terms do not apply to the biomethane injection stamp, the evolution of which will be defined in the deliberation of CRE deciding on the tariff for use of the GRDF distribution network for the period 2024-2027.

In addition, CRE may take into account, during the annual changes to the ATRT8 tariff, changes in the tariff structure, notably related to:

- the implementation of European network codes and/or guidelines;
- functioning of the single market zone France;
- changes to the offer of the TSOs;
- changes in the service quality incentive regulation of operators.

Finally, the storage tariff term will evolve according to the level set in an ad hoc deliberation by CRE at the end of the annual commercialisation campaign for gas storage capacities at auction.

2.3.5 Calculation of the CRCP balance on 1 January of year N

The overall balance of the CRCP is calculated before the final closure of the annual accounts. Thus, it is equal to the amount to be paid or deducted from the CRCP (i) for the past year, on the basis of the best estimate of annual expenses and revenues (known as the estimated CRCP), and (ii) for the previous year, by comparison between the expenses and revenues realised and the estimate that had been done a year earlier (known as the final CRCP), to which is added the balance of the CRCP not cleared for previous years.

The projected balance of the CRCP as of 31 December 2023 is taken into account for development of the projected revenues of the ATRT8 tariff cleared over the 4 years of the tariff and is, therefore, reset to 0 on 1 January 2024.

The final deviations to be paid to the CRCP for the year 2023 will be taken into account at the time of the annual update of 1 April 2025. The reference amounts and coverage rates used to calculate this final balance are defined in the ATRT7 deliberation of 23 January 2020, and in the ATRT7 tariff update deliberation of 31 January 2023[15].

The amount to be paid or deducted in the CRCP is calculated by CRE, on 31 December of each year, according to the deviation from the realised, for each item concerned, from the reference amounts defined in Appendix 4. All or part of the difference is paid to the CRCP, the share is determined according to the coverage rate provided for by this deliberation.

The expenses and revenues covered for all or part of the CRCP for the ATRT8 period are stated in 2.4.2 of this deliberation.

[15] Deliberation of the Energy Regulation Commission of 31 January 2023 deciding on the annual evolution of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga on 1 April 2023

2.3.6 Calculation of coefficients k, notably with a view to clearance of the CRCP balance

The evolution of the annual tariff schedule takes into account three coefficients $k_{national}$, k_{GRTgaz} and $k_{Teréga}$ which aim to clear, on 31 December of year N, the balance of the CRCP recorded on 31 December of year N-1. The coefficients $k_{national}$, k_{GRTgaz} and $k_{Teréga}$ are both capped at +/- 3%.

Coefficients k_{GRTgaz} and $k_{Teréga}$ are respectively determined so that the tariff evolution actually implemented makes it possible to cover, for each TSO and within the limit of the capping of the k coefficients, the sum of the following costs to be covered:

- the forecast allowed revenue, smoothed and updated;
- the CRCP balance.

The $k_{national}$ is defined as the average of the uncapped k_{GRTgaz} and the uncapped $k_{Teréga}$, weighted by the capacity subscription revenues of each operator. This weighted average introduces an opposite revenue gap in each of the operators which is compensated through adjustment of the inter-operator flow for year N (the principles of this flow are set in 2.8.6 of this deliberation).

The estimated revenues resulting from application of the tariff schedules actually implemented over this period are based on the estimated subscriptions considered in this deliberation.

2.4 Cost control incentive regulation

2.4.1 Regulatory incentive of operating charges

The ATRT7 tariff provided that net operating expenses, with the exception of certain predefined items that were difficult for operators to control, were the subject of a 100% incentive.

In view of the positive assessment of previous tariff periods and the favourable assessment of stakeholders formulated as part of the public consultation of 26 July 2023, CRE is renewing this principle for the ATRT8 tariff.

Thus, with the exception of the types of expenses and revenues covered in whole or in part by the CRCP, presented in 2.4.2 of this deliberation, any deviation from the trajectory set for the ATRT8 period will remain the loss or gain of the operator.

2.4.2 CRCP coverage of certain expense and revenue items

Network tariffs are calculated on the basis of assumptions about charges and revenue, which make it possible to define evolution trajectories for the various items. As indicated in section 2.2.3 of this deliberation, an a posteriori adjustment mechanism, the CRCP, makes it possible to take into account the differences between the expenses and revenue actually recorded, and the projected expenses and revenue on certain items previously identified, unpredictable and uncontrollable by the operators of the gas transmission networks.

CRE considers that the integration of an item in the CRCP must notably be addressed in light of the following two aspects:

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

These principles have been in effect for several tariff periods and are widely supported by the stakeholders that responded to the public consultation. Moreover, the tariff treatment cannot be reduced to a single alternative in terms of the coverage of the item, between 100% and 0% in the CRCP. Thus, for certain items that are poorly controllable and/or predictable, CRE considers that it is relevant to offer partial incentives to operators.

In its public consultation of 26 July 2023, CRE foresaw several changes compared to the ATRT7 period concerning coverage of the expenses and revenue of TSOs by the CRCP:

- <u>energy in-kind benefit charges ("agent tariff")</u>:

Employees of the Electricity and Gas Industries (IEG) branch and retirees who have worked for at least fifteen years in this branch, including GRTgaz, Storengy and GRDF, benefit from a preferential tariff for gas and electricity (known as the "agent tariff"). Each company in the branch that employs employees with IEG status who are part of the IEG pays EDF and Engie, in return, an amount each year to cover the difference between the agent tariff and the cost that these two companies indicate they incur for the supply of energy to agents.

Under ATRT7, these expenses were fully incentivized, like the majority of operating expenses. GRTgaz and Storengy request that they now be 100% covered by the CRCP for the ATRT8 tariff period, due to uncertainties affecting electricity and gas prices. GRDF requested that the differences due to price effects, i.e. the differences between the reference electricity and gas tariffs chosen by EDF and ENGIE and the electricity and gas tariffs set for the IEG agents, be covered by the CRCP.

Since the amount of the operators' repayments to EDF and Engie are set within the framework of a contract negotiated between the various companies concerned, during the public consultation, CRE considered that the maintenance of a regulatory framework encouraging the setting of a level was relevant for this compensation. In the consultation, CRE also foresaw maintaining an incentive relating to the volumes of energy consumed, in line with the conservation objectives set by the government.

Some actors share the CRE’s analysis and argue that maintaining this incentive is justified from the perspective of the energy conservation policy. Nevertheless, a large number of actors evoke the unpredictable and uncontrollable nature of energy prices to justify coverage of ANE expenses in the CRCP.

CRE decides to maintain the incentive on the "volume" part of the ANE charges, considering that it is partly controllable and predictable by GRTgaz in that the TSO can, in particular, carry out actions to encourage the beneficiaries of the agent tariff to adapt their energy consumption and that the consumption conservation efforts also apply to them.

With regard to price effects, CRE decides to cover 100% of the effects related to changes in market prices and taxes in the CRCP. Thus, for the tariff period, it retains a reference price for electricity and gas based on recurring and objective publications:

- for electricity, CRE retains the regulated tariffs for the sale of electricity (excluding tariff shield effects);
- for gas, it retains the benchmark sale price for gas, adapted to the average consumption of the beneficiaries of the agent tariff.

The price difference between the forecast trajectory and this reference, observed each year *ex post*, will be covered by the CRCP at 100%. On the other hand, deviations that could result from the choice of a reference price for calculation of the ANE different from that used by CRE will not be covered. The calculation methods are described in confidential appendix no. 5 of this deliberation.

- energy charges (motive energy and CO_2 quotas):

For the ATRT8, the operators requested that the annual update of the energy charge assumptions be taken into account directly in its allowed revenue for year N and not via the CRCP. CRE is not in favour of this, and wishes to maintain incentive regulation (price and volume) for this item.

In the coming months, CRE will continue the substantive work initiated with the TSOs for the implementation of such a system during ATRT8. In this stage, CRE decides to maintain the incentive framework as provided at the end of the ATRT7[16].

- amounts unpaid by biomethane producers:

Teréga requests 100% coverage in the CRCP for unpaid connection fees for biomethane production facilities. CRE considers that operators must make their best efforts to collect their receivables. Coverage of the charges related to these unpaid amounts will be assessed on a case-by-case basis on the basis of a substantiated file transmitted by the TSO concerned.

- charges related to congestion management and the interruptibility mechanism as well as the redistribution of excess revenue from capacity auctions:

GRTgaz believes that the rate of redistribution and recovery of the CRCP is not fast enough for these charges and revenue surpluses, which can vary in an uncertain and significant way. Therefore, GRTgaz requested that charges related to congestion resolution mechanisms and guaranteed interruptibility be re-invoiced directly to shippers on a monthly basis, via a mechanism similar to that put in place for balancing. CRE, as well as the respondents to the public consultation, are not in favour of this, because only the CRCP coverage makes it possible to distribute these burdens over all final consumers.

Consequently, the items included in the scope of the CRCP for the ATRT8 tariff are as follows.

[16] Deliberation of the Energy Regulation Commission of 31 January 2023 deciding on the annual evolution of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga on 1 April 2023

<u>Items covered in full by the CRCP</u>:

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 charges, taken into account at 100%, with the exception of those which are the subject of the incentive regulation mechanism of capital charges "excluding infrastructure" and for which only the difference between the forecast inflation and the inflation actually observed for the assets concerned by a revaluation of the RAB is taken into account (see paragraph 2.4.3.3);
- charges for GRTgaz related to the agreement between GRTgaz and Teréga for use by GRTgaz of the Teréga network. Since the revenues for Teréga are also fully covered by the CRCP, the impact of a variation in the contract amount is null for the overall cost of gas transmission in France;
- costs related, where applicable, to remuneration by the TSOs of consumers connected to the transmission networks 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 section 2.7): at the end of the tariff period, an assessment of the amounts actually spent by each TSO is done taking into account real inflation. If the TSO spent less than the forecast trajectory, 100% of the difference is returned to users *via* the CRCP. If the TSO has spent more than the forecast trajectory, the difference remains the responsibility of the latter;
- charges resulting from congestion resolution mechanisms within the single market area, to the extent that TSOs have acted effectively to minimise congestion;
- GRTgaz charges relating to the H gas to B gas conversion service;
- charges associated with contracts with other regulated operators, including storage operators;
- costs of studies not continued for major projects that have been the subject of prior approval by CRE or other stranded costs handled on a case-by-case basis, for which CRE approves coverage.

The revenue fully covered by the CRCP is as follows:

- the following tariff revenues;
  - revenue from the commercialisation of domestic output capacity of the main network, routing on the regional network and delivery, and biomethane injection capacities;
  - revenue from the commercialisation of storage entry and exit capacity;
  - revenue for the peak conversion of H gas into B gas;
- surplus revenue from capacity auctions;
- revenue from services for third parties, the implementation of which is uncertain and over which the TSOs have no influence (for example related to land use planning work);
- revenue for Teréga related to the agreement between GRTgaz and Teréga for use by GRTgaz of the Teréga network. Since the charges for GRTgaz are also fully covered by the CRCP, the impact of a variation in the contract amount is null for the overall cost of gas transmission in France;
- revenue generated by congestion resolution mechanisms in the context of the single market area;
- revenue from the connection of biomethane production units and GNV stations;
- revenue associated with contracts with other regulated operators, including storage operators;
- revenue associated with penalties received by TSOs for overruns of subscribed capacities (see 4.3.1.2);
- the payment made by the GRDs to the TSOs for the part of the biomethane injection term collected from producers connected to the distribution network, intended to cover the OPEX associated with the TSOs' backhauls (see section 2.8.5 of this deliberation);
- revenues for connection to combined cycle gas power plants (CCCG) and combustion turbines (TAC).

The interoperator flow between the two TSOs associated with the distribution of the evolution of the $k_{national}$ tariff evolution factor (see section 2.8.6 of this deliberation) is also covered at 100% in the CRCP.

<u>Items partially covered in the CRCP:</u>

- charges for motive energy (gas and electricity, including for biomethane backhauls) and purchases and sales of CO_2 quotas. These are covered:
    - at 90% by the CRCP for the fraction of the difference between the realised and the reference forecast trajectory of energy charges less than or equal, in absolute value, to 50% of the forecast trajectory;
    - at 100% by the CRCP for the fraction of the difference between the realised and the reference forecast trajectory of energy charges, in absolute value, beyond 50% of the forecast trajectory;
    - The difference between the updated trajectory and the initial trajectory is 100% covered in the CRCP.
- charges for consumables (THT), taken into account at 80% in the CRCP. The reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is covered at 100% in the CRCP;
- the routing revenue collected on the main upstream network at the entrance to the interconnections (IP) and from the LNG terminals (PITTM), taken into account at 90% (see 2.5). The difference between the updated trajectory and the initial trajectory is 100% covered in the CRCP. The same is true for the following related revenue:
    - revenue from access and transactions to PEG (Gas Exchange Point);
    - revenue from Alizés balancing services for GRTgaz and SET for Teréga;
    - revenue collected under the UIOLI (*Use it or lose* it) and UBI (*Use it and buy it*) mechanisms;
    - revenue from the auction of daily capacities.
- gains realised in the context of the sale of real estate assets or land, taken into account at 80% (see 2.2.2.5.2);
- deviations from the reference trajectory of the Teréga "TOTEX" experiment (see section 2.4.3.3), calculated at the end of the ATRT8 period, covered at 50% in the CRCP;
- differences in charges of energy benefits of GRTgaz related exclusively to price differences compared to the electricity and gas price reference adopted by CRE are 100% covered by the CRCP (see confidential Appendix 5); the rest of these differences in costs are not covered by the CRCP.

In addition, the bonuses and penalties resulting from the various incentive regulation mechanisms described in the following parts (incentive regulation of investments in 2.4.3, incentive regulation on commercialisation in 2.5, incentive regulation of quality of service in 2.6, and incentive regulation of R&D and innovation in 2.7 of the deliberation) are paid to the TSOs via the CRCP.

2.4.3 Incentive regulation of investments

2.4.3.1 Incentive to control costs for investments with a budget of more than 20 M€

The ATRT7 tariff provided an incentive to control costs for projects with a budget of more than 20 M€: the latter are the subject of an audit to set a target budget, and a bonus or penalty is applied to the operator according to the difference between the target budget and the actual expenditure, with a neutrality band of +/- 5% around the target budget.

During the ATRT7 tariff period, CRE audited 6 projects with a budget of more than 20 M€. On average, audits led to reported budget adjustments of -9% for TSOs. These audits also make it possible to analyse the costing methods of operators.

In its public consultation, CRE foresaw maintaining the existing measures for the ATRT8 tariff.

The majority of respondents are in favour of maintaining the target budget scheme following an audit for projects with a budget of more than 20 M€.

Consequently, for investment projects for which the decision to commit expenses would be taken starting from publication of this deliberation and whose estimated budget would be greater than or equal to 20 M€:

- CRE will audit the budget presented by the TSO and set a target budget taking into account, where appropriate, the steel price index (*Hot rolled coil* index – HRC);
- whatever the investment expenditure made by the TSO, the asset will enter the RAB at its real value when it is put into service (minus any subsidies);

- if the investment expenditure made by the TSO for this project is between 95% and 105% of the target budget, no premium or penalty will be applied;
- if the investment expenses incurred are less than 95% of the target budget, the TSO will benefit from a premium equal to 20% of the difference between 95% of the target budget and the investment expenses incurred;
- if the investment expenses incurred are greater than 105% of the target budget, the TSO will incur a penalty equal to 20% of the difference between the investment expenses incurred and 105% of the target budget.

Projects for which an incentive regulation has been defined during the ATRT7 period retain the mechanism implemented during this tariff period.

2.4.3.2 Incentive to control the costs of projects with a budget of less than 20 M€

The ATRT7 tariff introduced an incentive mechanism based on selection by CRE, without predefined criteria, of a few projects or categories of projects whose budget is below the threshold of 20 M€, in order to audit them and apply an incentive regulation identical to that applicable to investment projects whose budget is greater than 20 M€.

The majority of respondents are in favour of renewal of the incentive mechanism, part of which emphasises the need for the target budgets to remain exceptional in view of the costs involved. Several respondents, half of them infrastructure operators, are against it, for this same reason of loss of efficiency of the mechanism on smaller projects.

In view of the responses to the public consultation, CRE decides to renew the incentive mechanism for controlling the costs of projects outside major projects for the ATRT8 tariff period.

2.4.3.3 Incentive to control costs for investments "excluding infrastructure"

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

In fact, these expense items are, by nature, likely to give rise to trade-offs between investments and operating expenses. Therefore, this mechanism encourages operators to globally optimise all of their expenses on these three cost items. It consists in defining, for the tariff period, the evolution trajectory of capital charges, which are excluded from the scope of the CRCP[17]. Therefore, 100 % of realised gains or losses are retained by the operator during the tariff period. At the end of the tariff period, the actual value of fixed assets is taken into account in the RAB, which allows, for the following tariff periods, sharing of the gains or additional costs with the users.

In its public consultation of 26 July 2023, CRE considered renewing the incentive regulation mechanism for controlling investments "*excluding infrastructure*", considering that the feedback on the last tariff periods showed that this regulation mechanism effectively encouraged operators to control their costs.

In addition, CRE has introduced a specific experimental mechanism in the ATRT7 tariff for charges relating to Teréga's IS. This mechanism incentivizes the operator on a common trajectory including operating expenses and commissioning, and provides that the assets enter the RAB on the basis of an amount set *ex ante* in the trajectory, and not on the basis of the 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 integrating the deviations from the overall trajectory for up to 50% into the Teréga CRCP.

In its public consultation of 26 July 2023, CRE foresaw, for the ATRT8 period, reconsidering the relevance of this specific framework applied to Teréga's IS investments in relation to the framework applied to other operators.

Most stakeholders consider that a single regulatory framework could be applied to the IS investments of all operators. Teréga is nevertheless opposed to removal of the specific mechanism on its IS investments by claiming that this regulatory framework is more suited to its activity while being more efficient from a regulatory point of view.

CRE considers that the elements shared by Teréga (keeping to project schedules, better efficiency) and the assessment carried out by CRE make it possible to continue the experimentation of this specific regulatory framework for ATRT8.

In addition, Teréga requests that the costs related to the industrial IS be excluded from the scope of "excluding infrastructures" incentive regulations. CRE considers that this type of expenditure must remain incentivized in

[17] Framework applied solely to the scope of items relating to vehicles and real estate for Teréga.

the same way as other IS expenditure, due to the possibility of trade-offs between investments and operating expenses.

Consequently, for the ATRT8 tariff, CRE renews all the incentive regulation mechanisms for controlling investments "*excluding infrastructure*" applied to the various TSOs.

During the ATRT8 period, the capital charges for the so-called "*non-infrastructure*" assets incentivized will be calculated from the forecast values defined in section 3.1.4.3 of this deliberation. At the end of the tariff period, CRE will conduct an analysis of the commissioning trajectories of the investments concerned in order to ensure that any gains made during the tariff period are not offset by higher charges for the following tariff periods due, for example, to delays in certain projects.

The estimated amount of investments "*excluding infrastructure*" subject to this incentive regulation for GRTgaz and Teréga are, respectively, 90.9 M€ per year and 4.2 M€ per year on average (vehicles and real estate only for Teréga) or, respectively, about 20% and 4% of the total investments planned in the operator's trajectory for ATRT8.

The commissioning trajectory for Teréga's IS is set in section 3.1.4.3.2 of this deliberation. These investments represent approximately 11% of the operator's investments over the ATRT8 period.

2.5 Incentive regulation on commercialisation

The ATRT7 tariff provided, in particular, that the routing revenue collected on the main upstream network at the entrance to the interconnections (IP) and from the LNG terminals (PITTM) were covered at 80%, to encourage the TSOs to maximise subscriptions. In addition, the routing revenue reference trajectory was updated annually. The difference between the updated trajectory and the initial trajectory was 100% covered in the CRCP.

In their tariff files, GRTgaz and Teréga requested changes to these incentive regulation mechanisms applied to capacity commercialisation revenue:

- on one hand, considering that the end of long-term contracts and recent developments in flow patterns make it too difficult to forecast IP and PITTM subscriptions, operators wanted the corresponding revenues to be covered by the CRCP at 100 % or that the incentive be capped;
- on the other hand, Teréga requested, for the ATRT8, that the annual revision of the subscription assumptions be directly taken into account for calculation of its allowed revenue for year N+1.

CRE presented these requests in its consultation of 26 July 2023.

The majority of suppliers are in favour of maintaining an incentive regulation for upstream subscriptions so that operators can maximise the capacities made available to the market. Most of the other respondents consider that, in the new energy context, upstream subscriptions are more difficult for operators to anticipate. These respondents are in favour of 100% CRCP coverage of the corresponding revenue.

In view of the suppliers' responses to the public consultation, CRE decides that the routing revenues collected on the main upstream network at the entrance to the interconnections and from the LNG terminals shall be 90% covered by the CRCP in ATRT8.

Consequently, during the ATRT8 tariff, 90% of the routing revenue collected on the upstream main network (excluding output from the main network, storage entries and exits) is covered by the CRCP. This upstream revenue also includes:

- revenue from access and transactions at PEG (Gas Exchange Point);
- revenue from Alizés balancing services for GRTgaz and SET for Teréga;
- revenue collected under the UIOLI (Use it or lose it) and UBI (Use it and buy it) mechanisms;
- revenue from the auction of daily capacities.

The reference trajectory is updated annually. The difference between the updated trajectory and the initial trajectory is 100% covered in the CRCP.

Some other routing revenue, not very controllable by the TSOs, is 100% covered by the CRCP:

- revenue from the commercialisation of domestic output capacity of the main network, routing on the regional network and delivery, and biomethane injection capacities;
- revenue from the commercialisation of storage entry and exit capacity;
- revenue for the peak conversion of H gas into B gas;

2.6 Incentive regulation for service quality

The incentive regulation for service quality of TSOs aims to improve the service quality provided to users of transmission networks in areas considered to be particularly important for proper functioning of the gas market.

In its public consultation of 26 July 2023, CRE presented a review of the incentive regulation for service quality since 2009, when it was first implemented for TSOs. CRE noted that the service quality of operators had improved in areas of particular importance to network users.

In their responses, market players shared this positive assessment and considered that the incentive regulation for service quality constitutes a pillar of the tariff regulation framework, which makes it possible to ensure that economic efficiency is not achieved at the expense of the services provided by the networks.

Some suppliers wish to strengthen the indicators on the maintenance of TSOs.

CRE considers that the service quality indicators have generally made it possible to improve the performance of TSOs in the targeted areas. Nevertheless, given the feedback to the consultation on maintenance, CRE decided to continue working to complete the existing maintenance indicators (for example, a firm rate of available capacity over the year). An incentive may be put in place at mid-period.

The service quality indicators as well as the objectives set and the associated financial incentives are detailed in Appendix 2 of this deliberation.

2.6.1 Simplification of the current system

The incentive regulation for service quality has evolved to take into account the results obtained and feedback. Incentives and targets set for operators have been gradually strengthened in order to improve their performance.

To lighten the current system, CRE decided to do away with indicators concerning the availability of information related to functioning of the TRF. These indicators, not financially incentivized, measuring the availability rate of certain information, have always reached 100% since their implementation.

2.6.2 Biomethane Injection Indicators

The ATRT7 tariff did not provide any service quality indicators specific to biomethane producers. For this recent activity, for which the majority of sites are connected to the natural gas distribution network, CRE introduced, in the ATRD6 tariff of GRDF and ELD, monitoring of the following indicators (not financially incentivized):

- response time to detailed studies for biomethane project promoters;
- number of complaints following connection of the biomethane installations;

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

Therefore, during a workshop held on 10 May 2023 on the rise of renewable and low-carbon gases, CRE asked the stakeholders concerned about the relevant indicators to be taken into account to monitor the service quality of operators.

During this workshop, participants confirmed the importance of the issues identified by CRE concerning the downward trend in gas consumption that maintain uncertainties on the outlet of renewable and low-carbon gas production. Participants also shared a desire to accelerate the connection of facilities and develop flexibility solutions.

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

In its public consultation, it first foresaw introducing the two existing indicators in the ATRD6 tariff (response time to detailed studies for project developers and number of complaints following the connection of installations) into the ATRT8 tariff, extending them to all renewable and low-carbon gases, and adapting them to the specificities of TSOs. In fact, the latter do not conduct detailed studies but feasibility studies, through which they commit to project sponsors on the connection and injection conditions.

In addition, in its public consultation, CRE foresaw the introduction of an indicator relating to **the time taken to commission a backhaul**. In fact, the number of renewable and low-carbon gas production sites is set to increase over the ATRT8 period, which will require an increasing number of backhaul installations. It seems important that these installations be commissioned within a time frame compatible with commissioning of the production sites for which they will serve as an outlet.

In its public consultation, CRE also foresaw the creation of an indicator relating to **respect of the connection deadlines of renewable and low-carbon gas production sites**, taking into account the expected increase in power of the connections of these sites over the ATRT8 period.

Finally, in its public consultation, CRE foresaw the creation of an indicator relating to the **capped volumes of renewable and low-carbon gases**. In fact, CRE was able to notice uncertainties on the outlet of the production of renewable and low-carbon gases, due to a downward trend in gas consumption. The indicator foreseen by CRE aims to monitor evolution of the number of zones and producers concerned by the suppression of their production. Although this problem is more common on distribution networks, the objective would be to analyse the circumstances of local capping (seasonal or intra-monthly modulation, temporal and geographical evolution of the phenomenon, etc.), pending implementation of network strengthening investments validated by CRE.

Because of the novelty of these indicators, and despite projections of a rising number of renewable and low-carbon gas production sites, CRE does not wish to provide financial incentives for these indicators at this stage.

The majority of respondents share the issues presented by CRE and are in favour of the changes foreseen.

Given the favourable responses, CRE decided to introduce these 5 new indicators in ATRT8, namely:

- indicator related to response time to detailed studies for project promoters;
- indicator related to number of complaints following connection of the installations;
- indicator related to time for installation and commissioning of a backhaul;
- indicator related to compliance with connection deadlines for renewable and low-carbon gas production sites;
- indicator relating to the volumes of renewable and low-carbon gases capped.

Initially, they will not be financially incentivized, in order to take feedback into account. An incentive may be put in place at mid-period of ATRT8. These indicators are described in Appendix 2 of this deliberation.

2.6.3 Environmental indicators

The ATRT7 tariff included three environmental indicators, not financially incentivized:

- annual greenhouse gas emissions (equivalent in CO_2);
- monthly greenhouse gas emissions related to the volume of gas transmitted;
- methane emissions related to the volume of gas transmitted;

These indicators for monitoring greenhouse gas emissions include emissions proportional to the volumes of gas transported for which the control of the TSO is partial and mainly based on the optimisation of gas flows, and methane emissions on the networks, which result more directly from the network management mode, such as gas re-compression and re-injection operations during maintenance operations, rather than a release into the atmosphere.

GHG emissions relative to the volumes of gas transported followed a downward trajectory over the ATRT7 period, reflecting the efforts of the TSOs in this area.

Terèga requested to extend the financial incentive of the service quality monitoring system to the indicator on methane emissions.

The majority of respondents to the public consultation are in favour of incentive regulation of GHG emissions, but believe that it is useful to wait for the adoption of methane emissions regulations to calibrate the incentive.

CRE decides to set the trajectory of the charges concerned as well as their regulatory framework once the European regulation on methane emissions is adopted (see section 2.3.2). Targets and incentives related to greenhouse gas emissions can be put in place at the same time.

2.7 Incentive regulations for research, development and innovation

In the context of a rapidly changing energy landscape, network operators must have the necessary resources to conduct their research and development and innovation (R&D&I) projects, which are essential to provide an efficient and quality service to users and to evolve their tools for operating their networks. Network operators must, in return, use these resources efficiently and transparently.

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

- an asymmetrically incentivized R&D&I cost trajectory, which can be revised at mid-term: at the end of the tariff period, the amounts not spent over the period are returned to the consumers while the over-runs of trajectories remain the responsibility of the operators;
- annual transmission to CRE of technical and financial information for all ongoing and completed projects and the publication of a biennial public report.

In its public consultation, CRE foresaw maintaining the incentive terms of ATRT7. At this stage, CRE considers that these terms do not encourage operators to make trade-offs between savings on their R&D&I expenses and preparation for the future. In addition, the update of the mid-term trajectory review makes it possible to offer more flexibility to network operators in adapting their R&D&I program.

Finally, the *smart grids* counter system for gas operators, set up for the ATRT7 tariff period, was not used. In its public consultation, CRE foresaw not renewing it for the ATRT8 tariff period.

The majority of respondents are in favour of maintaining the current incentive arrangements.

The majority of respondents are in favour of abolishing the *smart grids* counter. Only two stakeholders consider that this counter provides useful flexibility within the tariff period.

Given the feedback from the consultation, CRE decided to renew the incentive regulation framework for innovation and R&D&I for the ATRT8 tariff period, and to abolish the mid-period *smart grids* scheme.

2.8 Inter-operator financial flows

2.8.1 Transfers between Teréga and GRTgaz resulting from equalisation of the tariff terms of the main network

The ATRT7 tariff provided for an inter-operator transfer from Teréga to GRTgaz which depends on the levels of exit subscriptions to Pirineos. This had been put in place after the merger of the TRF areas. Given the decline in subscriptions at this exit point, CRE decided to replace it, from 1 January 2024, by an inter-operator flow resulting from the equalisation of the tariff terms of the main network and ensuring the appropriateness between the charges and revenue associated with the main network of the two operators.

Acknowledgement of this flow in the allowed revenue of operators is calculated in 3.3.2 of this deliberation.

2.8.2 Inter-operator contract for use of the Teréga network by GRTgaz

GRTgaz, to transport gas from the Fos Tonkin and Fos Cavaou LNG terminals to the north of France, can use the Teréga transmission network. As such, GRTgaz and Teréga have signed a service contract, the amount of which (around 36 M€ per year) is included in the net OPEX trajectory of each of the two TSOs.

The costs of this contract are 100% covered in the CRCP.

2.8.3 Fee paid to GRTgaz by Fluxys for transport from the Dunkirk LNG terminal to the Belgian border

The *open season* conducted by GRTgaz between 2010 and 2011 in coordination with Fluxys allowed the launch of the necessary investments to create the Alveringem interconnection point. The entry capacities into Belgium from the Dunkirk LNG terminal are commercialised by Fluxys, and transport on the GRTgaz network is the subject of a service provided by GRTgaz to Fluxys.

In its deliberation of 12 July 2011[18], CRE indicated that, in view of the estimated costs of developing these capacities, the rate invoiced by GRTgaz to Fluxys for transport from the terminal to Belgium would be 45 €/MWh/d/year. CRE specified that this amount would be revised according to the actual level of investments.

In accordance with the aforementioned deliberation, CRE calculated the price of the service taking into account the costs at the end of the project. Consequently, on 1 April 2024, the price of the service totals 51.48 €/MWh/d/year.

2.8.4 Distribution of revenues to the PEG of the *Trading Region France*

Since creation of the single market zone on 1 November 2018, the revenue at PEG France has been distributed between the two TSOs operating the *Trading Region France*.

CRE decided to allocate these revenues in proportion to the operators' allowed revenue, i.e. 12% for Teréga and 88% for GRTgaz for ATRT8. Thus:

- when a shipper has signed a routing contract with GRTgaz only, or with GRTgaz and Teréga, it pays the PEG access tariffs to GRTgaz. GRTgaz pays 12% of these revenues to Teréga;
- when a shipper has signed a routing contract with Teréga, it pays the rates for access to the PEG to Teréga. Teréga pays 88% of these revenues to GRTgaz.

2.8.5 Payment of GRDs to TSOs for biomethane backhauls

The 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 several measures aimed at effectively developing the injection of biomethane into natural gas networks.

These main measures are the zoning of the connection of biogas production facilities to a natural gas network, the assessment and financing by the network operators of the associated costs, within the limit of a technical-economic ratio of Investments / Volumes ("I/V").

In view of the feedback from the ATRT7 period, as well as the feedback from the stakeholders to the public consultations of 26 July 2023 and 12 October 2023 relating to the price of GRDF's distribution network for the ATRD7 period, CRE will develop the injection fee system according to the procedures that will be described in GRDF's ATRD7 deliberation.

In addition, to avoid multiplying the number of contacts for producers, CRE had retained, for the ATRT7 period, the principle of invoicing of the injection fee by the network operator to which each producer is connected.

As a result, CRE has introduced a payment to the TSOs for revenue received by the GRDs for backhauls OPEX. The payment is made annually, according to the volume of injection revenue actually collected during the year, for producers connected for distribution that are assigned the level 3 injection fee. For ATRT7, the volumes associated with these transfers between operators were taken into account in the CRCP at 100%.

Since the majority of stakeholders that responded to the public consultations of 26 July 2023 and 12 October 2023 voted in favour of this measure, CRE is renewing the principle of a transfer between GRDF and the TSOs.

The form, the level of the injection fee, its annual evolution as well as the share of revenue collected under the injection fee that will be paid between GRDF and the TSOs concerned will be specified in GRDF's ATRD7 deliberation. The charges and revenues associated with these transfers between operators will be taken into account in the CRCP at 100 %. The biomethane injection tariff terms in force since 1 April 2023 will continue to apply between 1 April 2024 and 30 June 2024.

2.8.6 Inter-GRT transfer for the national annual evolution of the tariff terms of the main network

As described in 2.3.4 of this deliberation, the tariff terms of the main network will change annually taking into account a $k_{national}$ coefficient.

[18] Deliberation of the Energy Regulatory Commission of 12 July 2011 deciding on the conditions for connecting the Dunkirk LNG terminal to the GRTgaz network and on the development of a new interconnection with Belgium in Veurne

This coefficient, between +3% and -3%, corresponds to the weighted average of the capacity subscription revenue of the uncapped coefficients k_{GRTgaz} and $k_{Teréga}$, and will be applied uniformly to all tariff terms of the main transmission network.

As a result, an imbalance may appear between the projected revenue and the revenue to be received from each of the two TSOs. To compensate for this possible imbalance, the ATRT8 tariff provides that the TSOs will return the imbalance observed for the year concerned: the TSO that has received a surplus of revenue will return this surplus to the TSO in a revenue deficit. This payment is 100% covered by the CRCP.

2.8.7 Payment from TSOs to storage operators for storage compensation

Storage compensation corresponds to the difference between the estimated allowed revenue of the natural gas storage operators and the revenue they receive directly, mainly in the context of the auctioning of storage capacities.

It is collected by the TSOs, which pay it back to the storage operators.

3. Level of charges to be covered and trajectory of evolution of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga

3.1 Level of charges to be covered

3.1.1 Tariff requests of operators and the main issues they associate with them

3.1.1.1 GRTgaz

In its tariff request, GRTgaz anticipates the prolongation of the energy crisis over the ATRT8 period, and its consequences on its business, with significant congestion management costs and high volatility in energy prices.

In addition, GRTgaz believes that the decline in gas consumption observed since the start of the war in Ukraine could continue under the effect of conservation efforts and greenhouse gas emission reduction targets. GRTgaz also anticipates a significant decrease in capacity subscriptions to French 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 indicated that its tariff request aims to address the following issues:

- support the development of renewable gases: GRTgaz foresees an increase in the rate of connections of biomethane production units, and additional needs for monitoring the quality of gas;
- guaranteeing the industrial safety and security of the facilities, taking into account the new obligations related to the multi-fluid decree, and cybersecurity requirements;
- strengthening its contribution to security of supply;
- reducing its carbon and environmental footprint, in particular by reducing methane emissions and controlling its consumption of motive energy.

GRTgaz included in its tariff request an efficiency based on the redeployment of 0.5% of FTEs per year.

Since the public consultation, GRTgaz has updated its net operating expenses trajectory (see section 3.1.3).

Taking into account the issues listed above leads GRTgaz to request a total of net operating expenses (updated) and capital expenses of 2,256 M€/year on average for the ATRT8 period, an increase of 29% compared to the realised of the ATRT7 period.

The allowed revenue[19] corresponding to the updated GRTgaz request would increase by 35% in 2024 compared to the updated 2023 allowed revenue level.

3.1.1.2 Teréga

In its tariff request, Teréga identifies the ATRT8 period as a transition and security period. Thus, Teréga plans to strengthen the resilience of its industrial facilities and its IT system to guarantee security of supply, while preparing to receive renewable gases for the energy transition.

[19] The allowed revenue includes CCNs, CNEs, clearance of the CRCP and, for 2023, certain inter-operator smoothing and payment terms

In this context, Teréga indicated that its tariff request aims to address the following issues:

- the structural reversal of flows to Pirineos following the outbreak of the Russo-Ukrainian War. The end of long-term contracts with 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 increased network operating expenses and increased exposure to market prices;
- maintaining the company's regulatory compliance and safety to ensure the performance and resilience of facilities over time;
- preparing for the energy transition in order to prepare the network for the injection of gases such as biomethane, H_2 and CO_2.

Since the public consultation, Teréga has updated its net operating expenses trajectory (see section 3.1.3).

Taking into account the issues listed above leads Teréga to request a total of net operating expenses (updated) and capital expenses of 303 M€/year on average for the ATRT8 period, an increase of 26% compared to the realised of the ATRT7 period.

The allowed revenue[20] corresponding to Teréga's request would increase by 10% in 2024 compared to the updated 2023 level of allowed revenue.

3.1.2 Feedback from the public consultation

The majority of suppliers and some consumers express their concern about the level of charges to be covered by operators. Some stakeholders believe that any long-term increase in charges must be justified. They also question the discrepancy between the decrease in gas consumption and the increasing expenditure requests of the TSOs. Others call for limiting the tariff increase for the ATRT8, notably to limit the impact on French industry. The TSOs, their shareholders and the trade unions consider that the operators' requests are justified.

With regard to R&D expenses, the suppliers that expressed themselves share the position of CRE and, thus, consider that only expenses related to regulated activities should be covered by the tariff. Operators, their shareholders and their partners support the requests of the operators. Finally, some stakeholders want the tariff to cover at least part of the costs of converting the gas transmission network to other energy carriers.

3.1.3 Net operating expenses

To set the net operating expense trajectories of operators, CRE uses the following inflation assumptions (updated since the public consultation):

	2023	2024	2025	2026	2 027
CPI excl. tobacco	4.80%	2.50%	2.00%	2.00%	1.80%

3.1.3.1 Request of operators

3.1.3.1.1 GRTgaz

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

In current M€	2022 Realised	2024	2025	2026	2 027
Net operating expenses	797.1	1176.3	1079.7	1080.9	1074.8

GRTgaz's initial request assumes a sharp increase in net operating expenses (including energy expenses) between 2022 and 2024, of 379 M€ (+48%). Net operating expenses would then decrease by approximately 3% per year on average over the period 2024-2027. Excluding energy, the increase between 2022 realised and the 2024 request is +36%.

The main items showing a change between 2022 and 2024 in the request of GRTgaz's are as follows:

- "Energy" (increase of 127 M€ or +128%): GRTgaz anticipates an increase in expenses related to the consumption of fuel gas, mainly related to the increase in prices;

[20] The allowed revenue includes CCNs, CNEs, clearance of the CRCP and, for 2023, certain inter-operator smoothing and payment terms

- "H/B conversion" (increase of 90 M€, or +160%): GRTgaz forecasts an increase in charges related to the H gas to B gas conversion offer proposed to Zone B suppliers in France, due to the increase in the difference between Dutch and French market prices;
- "Salaries" (increase of 50 M€, or 15%): this increase is mainly related to the increase in salaries following the increase in inflation and the additional staff anticipated by GRTgaz, notably with a view to implementation of the future regulation aimed at reducing methane emissions from the energy sector;
- "Operation and maintenance" (increase of 30 M€, or +25%): this increase is mainly explained by inflation and additional expenses anticipated by GRTgaz for implementation of the future regulations to reduce methane emissions from the energy sector.

Since the public consultation, GRTgaz has updated its request for net operating expenses, taking into account the new inflation assumptions, changes in energy prices and changes in the tax rules specified by the draft finance law for 2024. GRTgaz has also updated its volume assumptions for compression energy.

GRTgaz has also sent additional requests for operating expenses to CRE. These requests include an increase in the needs for modelling the operation of the network (25 M€ over the ATRT8 period), new requests for the conversion of assets to hydrogen and CO_2 (18 M€ over the ATRT8 period) as well as evolution of a contract with Storengy (3 M€ over the ATRT8 period).

The forecast net operating charges requested by GRTgaz, updated for these items, are as follows:

In current M€	2022 Realised	2024	2025	2026	2 027
Net operating expenses	797.1	1,210.0	1,122.5	1,117.7	1,116.4

3.1.3.1.2 Teréga

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

In current M€	2022 Realised	2024	2025	2026	2 027
Net operating expenses	72.3	101.6	103.4	103.6	105.5

Teréga's initial request assumes a sharp increase in net operating expenses (including energy expenses) between 2022 and 2024, of 29 M€ (+41%). Net operating expenses would then increase by approximately 1% per year on average over the period 2024-2027. Excluding energy, the increase between 2022 realised and the 2024 request is 39%.

The main items showing a change between 2022 and 2024 in Teréga's request are as follows:

- "Operation and maintenance" (increase of 13 M€, or +52%): this increase is mainly explained by the additional expenses anticipated by Teréga for implementation of the future regulations to reduce methane emissions from the energy sector and by the creation of a new maintenance OPEX budget for depreciated assets;
- "Staff costs" (increase of 5 M€, or +12%): this increase is related to the increase in salaries due to the increase in inflation and the addition of new FTEs;
- "Energy" (increase of 4 M€, or +58%): Teréga anticipates an increase in expenses related to the consumption of fuel gas, mainly related to the increase in prices;
- "Expenses related to the removal of congestion" (increase of 3 M€, or +84%): Teréga forecasts an increase in charges related to the removal of congestion based on the costs observed during the winter of 2022-2023.

Since the public consultation, Teréga has updated its request for net operating expenses, taking into account the new inflation assumptions, changes in energy prices and changes in the tax rules specified by the draft finance law for 2024.

The net operating charges requested by Teréga, updated for these items, are as follows:

In current M€	2022 Realised	2024	2025	2026	2 027
Net operating expenses	72.3	101.9	104.1	104.9	106.7

3.1.3.2 Analytical approach retained

CRE has asked operators to present their tariff request in light of the latest realised figures by justifying any significant deviation from the 2022 realised and by breaking down each item in detail, in order to ensure that any additional needs cannot be covered by resources released by actions that are ending.

CRE mandated the firm H3P-ORCOM to conduct an audit of the operating expenses of the natural gas TSOs. The work took place between April and July 2023. The auditor's report, based on the operators' updated request, was published for each of the operators at the same time as the public consultation document of 23 July 2023.

This audit allowed CRE to have a good understanding of the operators' operating expenses and revenues recorded during the ATRT7 period and the projected operating expenses presented by the operators for the ATRT8 tariff period (2024-2027). The results of this audit are intended to:

- provide expertise on the relevance and justification of the trajectory of operators' operating expenses for the ATRT8 tariff period;
- assess the level of actual (2020-2022) and projected (2024-2027) expenses;
- make recommendations on the efficient level of operating expenses to be taken into account for the ATRT8 tariff.

CRE also audited certain specific items, including Research and Development (R&D) expenses, energy expenses, expenses related to the H gas to B gas conversion mechanism and expenses related to congestion management in the French market area.

The conclusions of the audit reports gave rise to exchanges with the operators during the month of July 2023. As such, the TSOs were able to comment on the results of the auditor's work.
Following the public consultation, exchanges continued between the TSOs and CRE on a number of items of net operating expenses. The level finally adopted by CRE is the result of these discussions with the TSOs and its own analyses of the adjustments recommended by the auditor.

3.1.3.3 Summary of the results of the audit and additional CRE adjustments on certain items

3.1.3.3.1 GRTgaz

- **<u>Results of the external audit</u>**

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

For this cost scope, at the end of his work, the auditor recommended the following trajectory for GRTgaz over the ATRT8 period:

In current M€	2022 realised	2024	2025	2026	2 027
Trajectory requested by GRTgaz	563.4	712.2	745.4	796.3	825.1
Realised 2022 inflated		603.4	614.1	623.9	633.6
Trajectory of the auditor		599.5	621.0	621.3	618.9
Impact on GRTgaz demand		-112.7	-124.4	-175.0	-206.2

The adjustments recommended by the auditor mainly relate to personnel costs, the industrial system, operational support and operating revenue.

Following the work done since the public consultation of 26 July 2023, CRE has restated this trajectory numerous times. The main adjustments it makes in relation to the request of GRTgaz are presented below.

Personnel charges

In its initial request, GRTgaz announced an increase in its workforce over the ATRT8 period (more than 80 additional FTEs in 2027 compared to 2022), mainly related to the development of green gases (around 30 additional FTEs), the evolution of methane emissions regulations (around 100 additional FTEs) and network modelling (5 additional FTEs), partially offset by redeployments of -0.5% / year (around 60 FTEs permitted, for example, by retirements and internal mobility).

Among its main volume adjustments, the auditor did not retain the increase in staff related to methane emissions regulations at this stage. In fact, as indicated in part 2.3.2, CRE decided to set the trajectory of operating costs related to application of the European regulation concerning the reduction of methane emissions as well as the regulatory framework for the gas operators concerned once the European regulation concerning the reduction of methane emissions from the energy sector is adopted. Regarding the additional needs related to the development of green gases, the auditor considered that only part of the operator's initial request is justified, given the planned installation of the biomethane injection and backhaul stations (about fifteen FTEs retained).

Regarding the price effect, the auditor retained different payroll change assumptions from those of GRTgaz, in particular a GVT (technical old-age adjustment) and the national base salary (SNB).

These volume and price adjustments by the auditor cumulatively represent a reduction in expenses of approximately 139 M€ over the ATRT8 period.

The auditor also adjusted the expenses related to the ANE (Advantage in Nature Energy) downward by approximately 21 M€, in view of changes in energy prices on the markets and taking into account projected energy consumption, revised downward due to the conservation efforts requested of the French people.

In total, the auditor recommended downward adjustments to the request of GRTgaz for personnel costs of -44.7 M€ on average per year (i.e., cumulatively over the ATRT8 period, - 178.9 M€), mainly in connection with the inclusion of a smaller number of job creations over the period.

CRE's analysis

CRE shares the general analysis of the auditor, but has made several adjustments following its discussions with the operator.

CRE does not fully retain the corrections to the estimated level of the National Base Salary and other remuneration parameters recommended by the auditor, but aligns them more closely with the historical practices observed. It takes recent data on the SNB and other remuneration elements into account.

CRE also retains the 5 additional FTEs for the modelling work of the network and the gas system.

With regard to the ANE, CRE updates the energy price assumptions and retains a projected consumption of electricity higher than that of the auditor. Nevertheless, the consumption trajectory adopted incorporates implementation by the agents of conservation efforts, in the same way as the rest of French households, in order to encourage regulated operators to promote conservation within the IEGs.

CRE also changes several assumptions concerning the number of student trainees, the cost of pensions and the CET and the rate of social charges in relation to the auditor's trajectory.

Industrial system

The auditor has adjusted the requested trajectory downward because GRTgaz considers the 2022 realised as a basis of expenses to which it adds anticipated non-recurring expenses between 2024 and 2027, but without subtracting the non-recurring expenses that occurred in 2022. Consequently, the auditor developed a cost trajectory for the industrial system by indexing the expenses incurred between 2020 and 2022 to inflation, and by only adding cost assumptions for the programs if it had enough information to consider that they were absent from the realised figures between 2020 and 2022 (major maintenance and maintenance programs for compressor stations and new biomethane stations considered relevant).

As previously stated, the auditor did not retain the charges related to the draft regulation concerning methane emissions that will be dealt with later.

The result is a downward adjustment of -40.3 M€ per year on average (i.e. -161.3 M€ cumulatively over the ATRT8 period) on the costs of the industrial system, since the request of GRTgaz is up sharply (217 M€/year on average for ATRT8) compared to 2022 (156 M€/year).

CRE's analysis

CRE shares the adjustments recommanded by the auditor but nevertheless adopts a trajectory based on expenses in 2022 indexed to inflation.

Operational support

Regarding the Information System (IS) item, the auditor considered that GRTgaz provided many qualitative elements, which nonetheless remained insufficient to quantitatively reconstruct the trajectory of expenses requested by GRTgaz and to analyse it in relation to the 2022 realised. In particular, the auditor understood that each IS expense line was developed autonomously by the responsible team, based on their own knowledge and forecasts. The trajectory of IS charges was therefore not constructed based on a set of common assumptions. In addition, GRTgaz built this trajectory of IS expenses from 2024 to 2027 by taking as a reference its projected expenses for 2023 and not the realised for 2022.

As a result, to ensure consistent changes compared to realised 2022, the auditor constructed a downward corrected trajectory of approximately -100 M€ over the ATRT8 period of the Information System item by indexing the realised recurring expenses of the 2020-2022 period to inflation, and by discarding certain provisions related to the renegotiation of contracts (considered to be covered by inflation). On the other hand, for non-recurring expenses corresponding to well identified projects, the auditor retained the requests of GRTgaz.

Regarding the real estate item, GRTgaz developed its trajectory with general application of the inflation chronicle for rents and provides for readjustment of the level of general services. The auditor developed its trajectory by indexing rents to the average change over the last 10 years in the Tertiary Activity Rent Index (ILAT), justifying that it is the benchmark for commercial and industrial leases and that retaining 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 M€ per year on average (i.e. -141.6 M€ cumulatively over the ATRT8 period) on operational support expenses, since the request of GRTgaz is up sharply (182 M€/year on average over the ATRT8) compared to 2022 (146 M€/year).

CRE's analysis

With regard to the IS, CRE conducted analysis of expenses including operating expenses and capital expenses, which are largely fungible and incentivized in a similar manner. CRE notes that the increase in operating expenses is offset by a decrease in capital expenses over the ATRT8 period. The analysis confirms GRTgaz's justification for the evolution of its expenses. CRE retains the operator's request, apart from certain provisions for increases in contract costs.

Operating income

The auditor constructed the revenue trajectory based on assumptions different from those of GRTgaz.

In particular, the auditor considered that the growth rate of biomethane fees and studies observed between 2020 and 2022 will remain stable until 2024. From 2025, the auditor based its trajectory on the forecasts of variation in the number of commissionings of biomethane equipment provided by the operator. This adjustment represents an increase of approximately 40 M€ over the ATRT8 period compared to the request of GRTgaz (which, on the contrary, expects relatively stable revenue compared to 2022).

The auditor also included certain operating revenue that GRTgaz had not taken into account (in particular the revenue from work and reimbursable services related to the MAGEO and Canal Seine Nord projects, for which the ongoing development of ATRT8 is considered probable and which was taken into account by GRTgaz in its trajectory of normative capital charges). This adjustment represents approximately 35 M€ over the ATRT8 period compared to the request of GRTgaz.

The auditor also adjusted the PMH (average hourly price) assumption used by GRTgaz to calculate its capitalised production, consistent with the price effect assumption used for the evolution of staff costs (i.e. an increase of 12 M€ over the ATRT8 period compared to the request of GRTgaz).

The result is an overall upward adjustment of operating revenue of 29.5 M€ per year on average (i.e. 117.8 M€ cumulatively over the ATRT8 period) for operating revenue, since the request of GRTgaz is down (188 M€/year on average over the ATRT8 period) compared to 2022 (195 M€).

CRE's analysis

CRE modifies the trajectory of biomethane fees and studies, in line with the trajectory of commissioning of the biomethane equipment. It also modifies the engineering revenue trajectory, so that it is consistent with the expected level of expenses to perform these services.

- **<u>CRE's adjustments</u>**

Energy charges

The request of GRTgaz concerning energy charges is based on the assumption of a reversal of the gas flow schema, now from south to north, of significant LNG entries, and a sustained level on IP exits.

Request of GRTgaz	2022 realised	2024	2025	2026	2 027
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*
Costs related to biomethane backhauls (M€)	-	1.0	1.4	1.5	2.5
CO_2 (M€)	5.3	16.0	16.6	16.0	13.9
TIC[21] (M€)	7.0	6.5	6.3	5.7	4.7
Total energy charges (M€)	**99.1**	**227.0**	**176.6**	**147.2**	**123.6**

<u>CRE's analysis</u>

CRE retains several adjustments in relation to this request, in particular:

- a downward adjustment of the EBT trajectory (Technical Assessment Variance). As the consumption volumes of this item are particularly volatile and difficult to predict, CRE retains the average volume observed over the ATRT7 period, i.e. 721 GWh/year. This adjustment leads to a decrease of 379 GWh/year, or 81.4 M€ compared to the request of GRTgaz over the ATRT8 period;
- a downward adjustment on the prices of CO_2 quotas based on common price assumptions and evolution of the allocation of free quotas, in line with European allocation rules. This adjustment led to a decrease of 1.2 M€ compared to the request of GRTgaz over the ATRT8 period.

CRE updated the prices based on the levels observed in the markets during the first half of November. Furthermore, CRE accepts the new request of GRTgaz concerning the new volumes of gas consumption for electricity in 2024 (not included in the table above), but not for years 2025 to 2027 due to the lack of justifications in relation to the flow patterns foreseen at that time.

[21] Domestic consumption tax

These adjustments lead to the following trajectory:

Trajectory retained by CRE	2022 realised	2024	2025	2026	2 027	Avg. ATRT8
Gas (M€) *Volumes (GWh)*	52.5 *2,334*	134.8 *1,890*	105.2 *2 001*	80.4 *1,885*	58.9 *1,683*	94.9 *1,865*
Electricity (M€) *Volumes (GWh)*	*34.5* *306*	49.7 *286*	38.8 *236*	*40.5* *236*	39.8 *241*	42.2 *250*
Costs related to biomethane backhauls (M€)	-	0.5	0.6	0.9	1.2	0.8
CO_2 (M€)	5.3	12.3	14.0	12.7	12.6	12.9
TIC[22] (M€)	7.0	5.8	6.4	5.7	5.6	5.9
Total energy charges (M€)	**99.1**	**203.1**	**165.1**	**140.2**	**118.2**	**156.6**

Energy charges are subject to a specific incentive regulation described in 2.4.2.

Research and Development (R&D)

Regarding R&D, the expenses of GRTgaz over the period 2020-2022 (92 M€, including 45.7 M€ in external expenses) were higher than the trajectory set by CRE (83 M€, including 46.1 M€ in external charges). GRTgaz explains this by labour costs that were higher than those foreseen in the trajectory, which were insufficiently offset by revenues. External expenses were at the level of the trajectory set by CRE.

GRTgaz requests, for the ATRT8 period, an R&D budget of 139 M€, an increase of about 13% compared to the 2020-2022 realised figure. This includes 67.8 M€ in external charges, 106.9 M€ in labour charges, and -35.1 M€ in revenue. The budget of GRTgaz is divided into five objectives which concern optimisation of the operation of the gas transmission network, reduction of the environmental impact as well as adaptation of the networks to the arrival of new gases, to which are added specific actions related to innovation, and a set of operational assessments.

<u>CRE's analysis</u>

CRE considers it important to retain projects that contribute to enhancing the safety, sustainability and efficiency of transport installations. Therefore, it promotes the coverage of initiatives related to the integrity, operational and maintenance safety of the network, as well as accident prevention. CRE also considers it crucial for GRTgaz to be able to fulfil its missions while optimising infrastructure in order to reduce the costs of injecting biomethane and controlling the impacts of green gases on the network. Thus, CRE granted the budget necessary for implementation of these projects to GRTgaz. On the other hand, expenses related to pure H_2 or CO_2 projects are not retained. In addition, some unjustified expenses are not included in the price trajectory. CRE retains a total budget of 125 million euros for the ATRT8 period, with a possibility of revision at mid-period.

This budget will allow GRTgaz to conduct R&D work aimed at improving the safety, integrity and performance of the network, reducing environmental impacts on the gas transmission network, controlling the impacts of green gases on the network (including mixed hydrogen) and adapting the network to changes in the energy system.

[22] Domestic consumption tax

CRE therefore retains the following R&D trajectory over the ATRT8 period:

In current M€	2022 Realised	2024	2025	2026	2 027
RICE revenues	-8.1	-6.5	-6.7	-6.8	-6.7
Labour charges	24.1	24.9	24.8	24.7	24.9
External charges	14.9	13.1	13.5	13.0	12.7
Trajectory retained by CRE	30.9	31.4	31.6	30.9	30.9

Note: the labour expenses in this table are also included in the scope of operating expenses analysed by the auditor. The request of GRTgaz for R&D labour costs has been adjusted in line with the auditor's adjustment for personnel costs. This amount will thus be taken into account in the R&D trajectory for the CRCP reference.

The trajectory of R&D expenses is subject to an asymmetric incentive described in 2.7 of this deliberation.

Conversion of assets

In the context of the energy transition, CRE considers it desirable for transmission system operators to have a budget to study the impact of converting reusable assets to other gases (including hydrogen or carbon dioxide). For ATRT8, CRE retains expenses equivalent to 0.1% of the average level of the regulated asset base during ATRT8, i.e. 9.4 M€ over the period for GRTgaz.

Charges related to congestion resolution mechanisms

The congestions observed in the TRF (*Trading Region France)* during the winter of 2022/2023 led to a sharp increase in congestion absorption charges for TSOs. These are related to activation of the localised spread, with 54.6 M€ spent during the winter of 2022/2023 (for a total volume of 5.1 TWh).

The trajectory of charges requested by GRTgaz in its tariff request is high, and assumes charges of the same order of magnitude as those of winter 2022/2023 until 2027.

<u>CRE's analysis</u>

CRE notes that GRTgaz's projected expenses for the period 2024-2027 are not consistent with the assumptions of the operator's congestion volumes presented, in particular as part of CRE's public consultation on the conditions of managing South-North congestion on the gas transmission networks[23] in June 2023 (i.e. approximately 3.8 TWh/year on average over the period). CRE also retains a purchase price consistent with the price differences between the French market and the Dutch market, which is a possible source of gas in the event of congestion.

CRE trajectory results in a downward adjustment of the GRTgaz request of - 166.9 M€ over the ATRT8 period.

WCR of stored gas

In its tariff request, GRTgaz proposes remuneration for the gas WCR stored at the WACC level (4.65% in the operator's request).

<u>CRE's analysis</u>

CRE considers that the remuneration of stock such as gas corresponds to a fixed asset, which must, therefore, be remunerated at the rate of assets under construction.

This leads to a downward adjustment of - 8.0 M€ over the ATRT8 period compared to the request of GRTgaz.

Other charges

CRE accepts the updated request of GRTgaz with regard to flexibility expenses and H/B conversion charges.

Efficiency

At the end of the line-by-line analysis, CRE notes that operating expenses excluding "system purchases" (i.e. energy, localised spread, interruptibility and H/B conversion) are about 100 M€ higher over the period (or about

[23] <u>see Appendix 3 of public consultation no. 2023-05 of 15 June 2023 on the conditions of management of South-North congestion on gas transmission networks</u>

4%) than the level of expenses for 2022, updated for inflation and adjusted for the effect of variation of an inter-operator contract.

In a context of rising energy costs and decreasing gas consumption, CRE considers that operators must make their best efforts to control their costs. CRE therefore retains an efficiency of 1%/year of controllable expenses excluding GRTgaz personnel expenses from 2025, i.e. 23.8 M€ over the ATRT8 period.

- **Summary of CRE's analysis**

In summary, the following tables present the trajectory of net operating expenses, resulting from adjustments retained by CRE for the ATRT8 tariff.

GRTgaz, in current M€	2022 realised	2024	2025	2026	2 027
Request of GRTgaz		1,210.0	1,122.5	1,117.7	1,116.4
Adjustment retained by CRE		-185.1	-191.7	-224.9	-252.3
Trajectory retained by CRE	**797.1**	**1,024.9**	**930.8**	**892.9**	**864.2**

GRTgaz, In current M€ – excluding "system purchases"	2022 realised	2024	2025	2026	2 027
Request of GRTgaz		773.7	802.1	852.0	878.5
Adjustment retained by CRE		-111.4	-119.5	-157.5	-181.1
Trajectory retained by CRE	**610.3**	**662.3**	**682.7**	**694.5**	**697.4**

GRTgaz, In current M€ – "system purchases"	2022 realised	2024	2025	2026	2 027
Request of GRTgaz		436.3	320.4	265.7	237.9
Adjustment retained by CRE		-73.7	-72.2	-67.4	-71.1
Trajectory retained by CRE	**186.8**	**362.6**	**248.2**	**198.4**	**166.8**

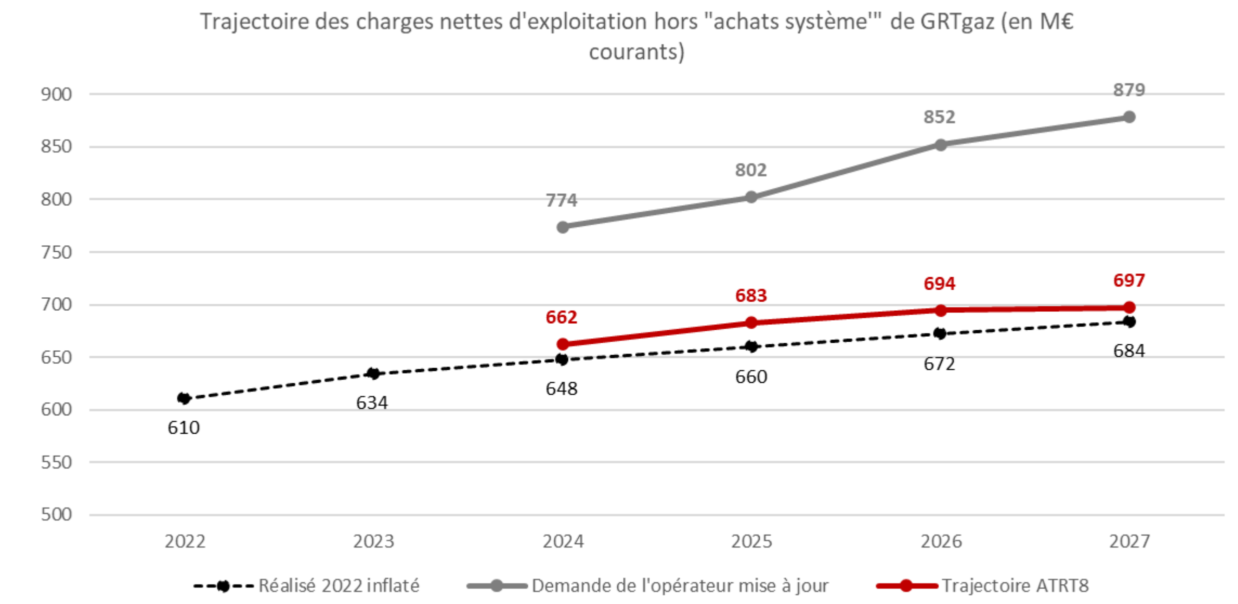
Note: "System purchases" include energy charges, congestion management charges, H/B conversion and interruptibility charges.

The trajectory retained by CRE gives GRTgaz the means to:

- have the necessary staff to fulfil its missions, including in terms of biomethane development and modelling of its network;
- maintain a remuneration policy aligned with historical practices, taking into account the effects of recent data on the SNB and other elements of remuneration;
- to have the necessary resources to continue the integration of biomethane into its networks, in line with the energy policy guidelines;
- guarantee the industrial security of its facilities, maintaining the level of expenditure observed in the last tariff period;
- continue to redesign and maintain its information system, including with regard to cybersecurity (+12% of IS operating expenses compared to the real 2022 with inflation);
- to perform R&D work on safety, network performance, the integration of renewable gases and preparation of the network for structural changes related to the energy transition;
- to examine the possibility of converting part of its assets to hydrogen or CO_2 (9,4 M€ over the period).

The ATRT8 tariff also provides for a rendez-vous clause to integrate the charges related to implementation of the European regulation to reduce methane emissions (see section 2.3.2).

Thus, the trajectory set by CRE forecasts a 29% increase in the net operating expenses of GRTgaz between 2022 and 2024 (+9% excluding "system purchases"). Net operating expenses then change by -6% per year on average over the period 2024-2027 (+2% per year excluding "system purchases").



Note: the inflated level realised is corrected for the effect of changes in forecast expenses of a contract with another regulated operator.

3.1.3.3.2 Teréga

- **Results of the external audit**

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

For this cost scope, at the end of his work, the auditor recommended the following trajectory for GRTgaz over the ATRT8 period:

In current M€	2022 realised	2024	2025	2026	2 027
Trajectory requested by Teréga	58.1	72.7	72.7	73.9	76.1
Realised 2022 inflated		62.2	63.3	64.3	65.3
Trajectory of the auditor		58.1	58.5	59.0	60.6
Impact on Teréga demand		-14.6	-14.2	-14.9	-15.5

The main adjustments recommended by the auditor relate to structural costs, operating and maintenance costs, personnel costs and operating revenue.

Following the work done since the public consultation of 26 July 2023, CRE has restated this trajectory numerous times. The main adjustments it makes in relation to the request of GRTgaz are presented below.

Operating revenue

The main adjustments recommended by the auditor concern the "other revenue" sub-item, composed of intra-group services and third-party services.

In fact, these involve services that are not predictable several years in advance, and Teréga retains a fixed amount of 0.1 M€/year. For his part, the auditor developed the trajectory of the sub-item by indexing the 2020-

2022 output to inflation, justifying that even if these services are unpredictable, this construction is more robust than that requested by Teréga.

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

CRE's analysis

CRE retains Teréga's trajectory regarding third-party services, given the uncertainty surrounding implementation of these projects.

Costs of operation and maintenance

Teréga requested the coverage of operating costs related to application of the European regulation concerning the reduction of methane emissions. As indicated in section 2.3.2, CRE decides to set the charge trajectory as well as the regulatory framework for the gas operators concerned once the draft European regulation on the reduction of methane emissions from the energy sector is adopted. This item has not been addressed by the auditor.

The auditor also rejected the voluntary carbon offset, requested by Teréga, which is a choice of Teréga that is not directly part of the expenses necessary to fulfil its TSO missions.

Finally, the auditor rejected the request for additional OPEX for the fully depreciated assets, corresponding to a request for changes to Teréga's regulatory framework that CRE does not retain in this deliberation (see section 2.2.2.1).

Thus, the trajectory recommended by the auditor is in line with the 2022 realised figures in current euros, on average, over the ATRT8 period.

The result is a downward adjustment of -6.5 M€ per year on average (i.e. -26 M€ cumulatively over the ATRT8 period) on the costs of operation, maintenance of the network, studies and other expenses related to operation, since the request of Teréga is up sharply (37 M€/year on average for ATRT8) compared to 2022 (26 M€/year).

CRE's analysis

CRE retains a budget higher than that of the auditor for the ATRT8 period. This notably corresponds to charges for which Teréga submitted elements of justification to CRE, which had not been sent to the auditor.

Personnel charges

Teréga's request includes new FTEs (transport and storage combined) from 2024 for new needs over the ATRT8 tariff period (CO_2, H_2, methane emissions, cybersecurity, asset management, regional institutional relations). The auditor considered that only some additional FTEs were justified, in that the others were not essential for fulfilling its TSO missions because they were related to unregulated activities and since Teréga had room to manoeuvre in redeploying its current resources (retirements, internal mobility, etc.). As for operating expenses, the auditor did not retain the expenses related to the regulation concerning methane emissions, which will be addressed later by CRE.

Regarding the price effect, the auditor used different assumptions from those of Teréga.

This results in a downward adjustment of -1.7 M€ per year on average for transport (i.e. a cumulative amount of -7 M€ over the ATRT8 period) [and] staff costs.

CRE's analysis

CRE retains a recruitment trajectory higher than that recommended by the auditor in order to take into account the cybersecurity issues that Teréga will have to face during the ATRT8 tariff period, to support the development of biomethane and to meet the challenges of regional institutional relations.

CRE retains the salary evolution trajectory requested by Teréga.

CRE notes that Teréga's request includes participation that is significantly higher than in the past. CRE maintains a level aligned with historical practices.

Overhead costs

In its tariff file, Teréga incorporated an inflation lag of one year, justifying that the inflation of year N mainly affects the expenses of year N+1. The auditor did not consider this request relevant, particularly given the tariff framework that protects the TSOs from changes in year N and, therefore, did not retain this request in its trajectory.

Regarding the endowment fund requested by Teréga, the auditor considered that it was a company choice that was specific to the Teréga entity, and that this decision was not necessary to fulfil its TSO missions and, therefore, did not accept this request.

The result is a downward adjustment of -3.2 M€ per year on average (i.e. -13 M€ cumulatively over the ATRT8 period) on structural costs, since the request of Teréga (15.7 M€/year on average for ATRT8) was up compared to 2022 (11.6 M€/year).

CRE's analysis

Teréga provided additional elements to justify its expenses for guard services. CRE accepts the operator's request.

CRE retains communication, endowment and CSR expenditure in continuity with existing expenditure.

Information system

CRE conducted analysis of IS expenses including operating expenses and capital expenses, which are largely fungible and incentivized in a similar manner. CRE notes that the change in total expenses is less than the 2022 realised, inflated for the overall scope of Teréga (transport and storage).

CRE retains a level of operating expenses comparable to the operator's request. In particular, CRE does not retain the effects of inflation lag (see structural costs).

Imposts and taxes

CRE updates the calculation of taxes taking the latest known rates into account.

Depreciation of stock

CRE retains a trajectory consistent with Teréga's annual assumptions.

- **CRE's adjustments**

Energy charges

Teréga's request for energy charges (gas, electricity, CO_2) is based on the assumption of a reversal of the gas flow schema, now from south to north.

Request of Teréga	2022 realised	2024	2025	2026	2 027
Gas (M€) *Volumes (GWh)*	1.1 *83.7*	4.9 *162*	5.3 *162*	5.3 *162*	5.2 *162*
Electricity (M€) *Volumes (GWh)*	5.4 *33.2*	5.4 *31.7*	4.6 *31.7*	5.4 *32.9*	5.2 *34*
CO_2 (M€)	0.2	0.9	1.0	1.2	1.3
TIC (M€)	0.4	0.4	0.4	0.4	0.4
Total energy charges (M€)	7.2	11.6	11.3	12.3	12.1

CRE's analysis

CRE retains, on the basis of flow assumptions consistent with those foreseen for Teréga's energy charges, several adjustments in relation to this request, in particular:

- a downward adjustment of the EBT trajectory (Technical Assessment Variance). As the consumption volumes of this item are particularly volatile and difficult to predict, CRE retains the average volume observed over the ATRT7 period (including the estimated value for 2023), i.e. 54.3 GWh/year. This adjustment leads to a decrease of 0.7 M€ compared to Teréga's request over the ATRT8 period;
- a downward adjustment on the prices of CO_2 quotas based on common price assumptions and evolution of the allocation of free quotas. This adjustment led to a decrease of 0.7 M€ compared to Teréga's request over the ATRT8 period.

CRE updated the prices based on the levels observed in the markets during the first half of November. Teréga also requested coverage for its purchases of guarantees of origin for electricity. CRE does not accept these requests because purchases of guarantees of origin are not mandatory.

These assumptions lead to a cumulative downward adjustment in Teréga's demand of approximately – 4.1 M€ over the ATRT8 period, a decrease of approximately 8.6%.

Trajectory retained by CRE	2022 realised	2024	2025	2026	2 027	Avg. ATRT8
Gas (M€) *Volumes (GWh)*	1.1 *83.7*	4.5 *151.3*	5.0 *151.3*	5.2 *151.3*	5.0 *151.3*	**4.9** ***151.3***
Electricity (M€) *Volumes (GWh)*	5.4 *33.2*	4.0 *31.7*	4.1 *31.7*	5.2 *32.9*	5.0 *34.0*	**4.6** **32.6**
CO_2 (M€)	0.2	0.8	0.9	1.0	1.0	**0.9**
TIC (M€)	0.4	0.4	0.4	0.4	0.4	**0.4**
Total energy charges (M€)	**7.2**	**9.7**	**10.4**	**11.8**	**11.4**	**10.8**

Energy charges are subject to a specific incentive regulation described in 2.4.2.

R&D

Regarding R&D, Teréga's spending between 2020 and 2022 (4.5 M€) was below the trajectory set by CRE (4.9 M€). Teréga notably explains this underspending by the transfer of operating expenses into capital expenditure and by the uncertainty inherent in R&D projects.

Teréga requests, for the ATRT8 period, an R&D budget (excluding staff costs) of 29.4 M€ (or 7.4 M€/year on average over the period, a significant increase compared to ATRT7), distributed across six objectives which concern integrity, performance and safety, reduction of the environmental impact as well as adaptation of the networks to the arrival of new gases. The budget also includes two projects (Hysow and Pycasso), which focus on the development of H_2 and CO_2 transport.

CRE's analysis

CRE is in favour of transport operators continuing to work on projects to optimise and secure gas infrastructure, while reducing environmental impact. It also retains the budgets relating to the impacts of mixed hydrogen in Teréga's existing facilities. On the other hand, expenses related to unregulated activities are not included in the price trajectory. Consequently, CRE retains a budget of 10.0 M€ for the ATRT8 period, with the possibility of revision at mid-period.

This budget will allow Teréga to conduct R&D work to improve network monitoring and integrity, develop cybersecurity tools, ensure the safety of agents, and assess and limit the impact of green gases (including mixed hydrogen) on network integrity.

CRE therefore retains the following R&D trajectory over the ATRT8 period:

Teréga, in current M€ – R&D	2022 realised	2024	2025	2026	2 027
R&D	1.2	2.4	2.5	2.0	2.1
R&D management	0.2	0.2	0.3	0.3	0.3
Trajectory retained by CRE	**1.4**	**2.7**	**2.8**	**2.2**	**2.3**

Conversion of assets

In the context of the energy transition, CRE considers it desirable for transmission system operators to have a budget to study the impact of converting reusable assets to other gases (including hydrogen or carbon dioxide). For ATRT8, CRE retains expenses equivalent to 0.1% of the average level of the regulated asset base during ATRT8, i.e. 1.9 M€ over the period for Teréga.

Charges related to congestion resolution mechanisms

The congestions observed in the TRF (*Trading Region France)* during the winter of 2022/2023 led to a sharp increase in congestion absorption charges for TSOs. These are related to activation of the localised spread, with 54.6 M€ spent during the winter of 2022/2023.

The trajectory of charges requested by Teréga in its tariff request is high, and assumes higher charges than those of winter 2022/2023 until 2027.

<u>CRE's analysis</u>

CRE notes that Teréga's projected expenses for the period 2024-2027 are not consistent with the assumptions of the operator's congestion volumes presented, in particular as part of CRE's public consultation on the conditions of managing South-North congestion on the gas transmission networks[24] in June 2023 (i.e. approximately 3.8 TWh/year on average over the period). CRE also retains a purchase price consistent with the price differences between the French market and the Dutch market, which is a possible alternative source to reduce congestion.

CRE's trajectory results in a downward adjustment of the Teréga request of - 26.9 M€ over the ATRT8 period.

Interruptibility Mechanism Charges

The guaranteed interruptibility scheme was revised in 2022 in order to strengthen national gas supply security for the winter of 2022/2023. This ultimately did not generate any charges for the operators.

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

<u>CRE's analysis</u>

In the absence of information on a possible evolution of the mechanism and the form it could take, CRE sets the corresponding trajectory at 0 for the ATRT8 period, as is the case for GRTgaz. CRE also recalls that this item is covered in the CRCP.

Efficiency

At the end of the line-by-line analysis, CRE notes that operating expenses excluding "system purchases" are close to the level of expenses incurred in 2022 (less than a 1% difference over the ATRT8 period).

Consequently, CRE does not retain any additional efficiency for Teréga.

[24] see Appendix 3 of public consultation no. 2023-05 of 15 June 2023 on the conditions of management of South-North congestion on gas transmission networks

- **Summary of CRE's analysis**

In summary, the following tables present the trajectory of net operating expenses, resulting from adjustments retained by CRE for the ATRT8 tariff.

Teréga, in M€ current	2022 realised	2024	2025	2026	2 027
Request of Teréga		101.9	104.1	104.9	106.7
Adjustments retained by CRE		-25.3	-26.5	-25.6	-26.2
Trajectory retained by CRE	**72.3**	**76.6**	**77.6**	**79.3**	**80.5**

Teréga, in current M€ – excluding "system purchases"	2022 realised	2024	2025	2026	2 027
Request of Teréga		80.2	82.2	81.4	83.5
Adjustments retained by CRE		-14.4	-16.0	-14.7	-15.2
Trajectory retained by CRE	**60.7**	**65.8**	**66.2**	**66.7**	**68.3**

Teréga, in current M€ – "system purchases"	2022 realised	2024	2025	2026	2 027
Request of Teréga		21.7	21.9	23.5	23.2
Adjustments retained by CRE		-10.9	-10.5	-10.8	-11.1
Trajectory retained by CRE	**11.5**	**10.8**	**11.4**	**12.6**	**12.1**

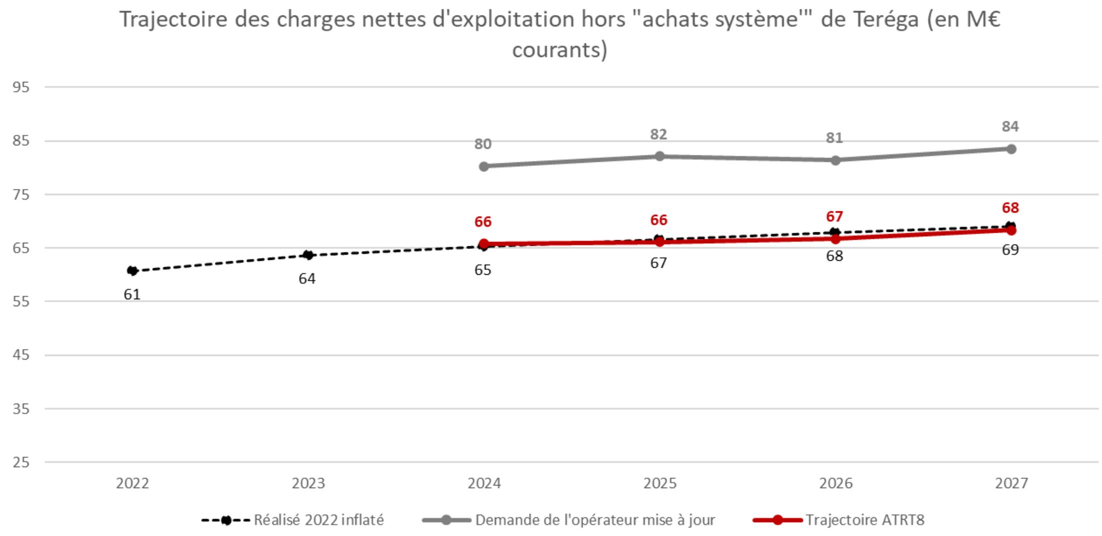
Note: "system purchases" include energy charges, congestion management charges and interruptibility charges.

The trajectory retained by CRE notably gives Teréga the means to:

- maintain a remuneration policy aligned with historical practices observed and taking into account the effects of recent data;
- have the necessary staff to fulfil its missions, including with regard to cybersecurity, project management, biomethane integration and institutional affairs;
- implement its maintenance program and, thus, operate its network under optimal safety conditions, with a budget in line with the expenses incurred, adjusted for inflation;
- keep its information system up to date, retaining most of the expenses requested by the operator;
- conduct R&D work on network monitoring and integrity, cybersecurity tools, agent security, as well as the impact of green gases (including mixed hydrogen) on network integrity, with a trajectory up by about 25% compared to the real figure adjusted for inflation;
- to examine the possibility of converting part of its assets to hydrogen or CO_2 (1,9 M€ over the period).

The ATRT8 tariff also provides for a rendez-vous clause to integrate the charges related to implementation of the European regulation to reduce methane emissions (see section 2.3.2).

Thus, the trajectory set by CRE forecasts a 6% increase in the net operating expenses of Teréga between 2022 and 2024 (8% excluding "system purchases"). Net operating expenses then change by +2% per year on average over the period 2024-2027 (+1% per year excluding "system purchases").



3.1.4 Calculation of normative capital charges

3.1.4.1 Average weighted cost of capital

3.1.4.1.1 Request of operators

3.1.4.1.1.1 GRTgaz

GRTgaz's tariff request was established using a weighted average cost of capital (WACC) of 4.65% (actual, before taxes) higher than that of the ATRT7 tariff (4.25%). This request is based on the conclusions of a study commissioned by the Engie group's regulated natural gas infrastructure operators from an external consultant.

In its tariff file, GRTgaz also uses the rate of 2.8% (nominal, before taxes) for the remuneration of AuCs.

3.1.4.1.1.2 Teréga

Teréga's tariff request was established using a WACC of 4.70% (real, before taxes), higher than that of the ATRT7 tariff (4.25%). This request is based on the conclusions of a study commissioned by Teréga from an external consultant.

In its tariff file, Teréga also uses a rate of 2.9% (nominal, before taxes) for the remuneration of AuCs.

3.1.4.1.2 Summary of the results of the external audit of CRE

In the context of work to prepare the ATRT8 tariff, CRE re-examined the assumptions and parameters used to calculate the operators' remuneration rate. For this purpose, it asked Compass Lexecon to perform an audit and analysis of the remuneration requests of the two TSOs, the storage operators and GRDF on the basis of the conclusions of their advisers. The consultant's report was published at the same time as the public consultation of 23 July 2023 on CRE's website.

After auditing the operators' request, the auditor recommended several ranges of WACCs depending on the assets to which they apply. For historical assets, the auditor recommended a range of WACC, nominal before tax, of between 3.72% and 4.14%, i.e. a before-tax range of real WACC between 2.51% and 2.93%. For new assets, the auditor recommended a nominal before-tax range of WACC of between 5.69% and 6.21%, i.e. a before-tax range of real WACC between 2.74% and 4.23%.

3.1.4.1.3 CRE's analysis

CRE's method of determining the weighted average cost of capital is based on a WACC with a normative structure to ensure an appropriate return on capital invested. Until now, it was based on the average of the rates observed over the last ten years, reflecting the long lifespan of gas network infrastructures. This method, which has changed very little over three tariff periods, has made it possible to maintain the attractiveness of the energy infrastructure in France, while taking into account the downward trend in rates observed over the past 10 years.

After this long period of decline, interest rates have been rising rapidly for about a year. Faced with this new situation, CRE is changing the method of calculating the WACC to better account for the dynamics of short-term interest rates.

In the July 2023 public consultation, CRE indicated that it foresaw a WACC in a range of between 2.9% and 4.2% (real before tax), based on weighting of a long-term rate according to the method used for the ATRT7, and a short-term rate based on the analysis of shorter-term parameters and retaining a weighting of 80/20, respectively, between the two terms. This range was down compared to the WACC of the ATRT7 tariff (4.25%). In nominal rate before taxes, the range was 4.4% - 5.5%.

In this context and taking into account the feedback from the public consultation (see section 2.2.2.3), CRE decides, for the ATRT8 tariff period, to change the method of calculating the weighted average cost of capital by weighting two rates:

- a rate determined according to the method used for the ATRT7 and previous tariffs, based on the analysis of long-term parameters, which shows a real rate of 3.7% before taxes (i.e. 4.9% nominal before taxes, from which is restated the average inflation of 1.2% observed over the last ten years);
- a rate based on taking into account more recent economic data which shows a real rate of 5.5% before taxes (i.e. 7.6% nominal before taxes, from which is restated the average forecast inflation of 2.0% over the ATRT8 tariff period).

The weighting chosen by CRE is based on a normative distribution of the respective share of new and old assets, evaluated during the ATRT8 tariff period for a gas operator, and is set for the tariff period in question at 80% for the rate based on long-term data, and 20% for the rate based on more recent data.

As a reminder, the WACC is calculated by applying the following formulas:

Nominal WACC before corp. tax = [(TSR + debt spread) x (1 – financial expense deductibility x corp. tax) / (1 - corp. tax)] x g + (TSR + β x PRM) / (1 - corp. tax) x (1 - g)

Real WACC before corp. tax = (1 + nominal WACC before corp. tax) / (1 + inflation) – 1

For the ATRT8 tariff, CRE retains the value of 4.1% (real, before taxes) as WACC to remunerate the so-called "historical" assets of the RAB of gas TSOs. For so-called "new assets", CRE retains a WACC of 5.4% (nominal, before taxes). The rounded values retained by CRE for each of the parameters are shown in the table below:

ATRT8 WACC parameters (rounded values)			
	Long-term data	Short-term data	Weighted value (80% - 20%)
Nominal risk-free rate (TSR)	1.3%	3.8%	1.8%
Spread of debt	1.1%	0.5%	1.0%
Bêta of assets	0.47		
Bêta in equity (β)	0.82		
Market Risk Premium (MRP)	5.2%		
Leverage (debt/(debt+equity)) (g)	50%		
Corporate tax rate (IS)	25.83%		
Cost of debt (nominal, before corp. tax)	2.4%	4.3%	2.8%
Cost of equity (nominal, after corp. tax)	5.5%	8.1%	6.0%
WACC (nominal, before corp. tax)	4.9%	7.6%	5.4%
Inflation	1.2%	2.0%	1.3%
WACC (real, before corp. tax)	3.7%	5.5%	4.1%

Compared to the values taken into account to define the WACC of the ATRT7 tariff, the main changes, consistent with the evolution of macroeconomic and financial data, notably relate to evolution of the risk-free rate, the beta of assets and taxation.

The risk-free rate is set at 1.8% and is determined by observing the yields of French government bonds (“OAT”), considered the least risky investments. This rate is determined as the weighting between the 10-year average of the OAT with a 15-year maturity and the average of the four implied forward rates from the years 2024 to 2027 of an OAT with a 15-year maturity. The weighting used is 80/20 for the tariff period considered as stated above. For determination of the risk-free rate, CRE has retained the observation of the yields of OATs no longer of a 10-year maturity as was the case until now, but of a 15-year maturity.

The debt spread is set at 1.0% and is determined on the observation of average bond yields iBoxx EUR NF 10+ BBB'; for long-term data over a 10-year average and for short-term data over a 1-year average. The weighting between these two values is also 80/20 for the tariff period considered as described above.

Compared to the previous tariff period, the beta of the asset is lowered from 0.50 to 0.47. CRE bases its decision on market observations and betas of the activity of gas operators in Europe. This decrease is also justified by the level of protection provided by the regulatory framework of the ATRT8 tariff, which provides greater protection to operators, notably against changes in energy prices. In addition, the regulatory framework showed its strong resilience during the successive Covid and energy crises. Overall, CRE considers that the regulatory framework is consistent with a measured decline in the asset beta to 0.47. In fact, risks persist for the future of gas infrastructures, which justifies retaining a higher *beta* than that of electricity network tariffs.

CRE also takes into account the reduction in the standard corporate tax rate to 25.0%, combined with the social contribution corresponding to 3.3% of the amount of the corporate tax, i.e. a tax rate of 25.83%.

In accordance with what is stated in paragraph 2.2.2.4, assets under construction (AuC) are remunerated at the cost of the nominal debt before tax, i.e. 2.8% under the ATRT8 tariff.

3.1.4.2 Investments

3.1.4.2.1 GRTgaz

The trajectory of capital expenditure planned by GRTgaz over the ATRT8 period is slightly higher in current euros, with average expenditure of around 460 M€ per year over this period, compared to 419 M€ per year during the ATRT7 period.

In particular, GRTgaz foresees:

- an increase in expenses related to connections and services for third parties (+142 M€ over the period, or + 50%), mainly related to acceleration of the number of backhauls done (+112 M€ over the period);
- an increase in expenditure related to obsolescence (+ 67 M€ over the period, or +22%). This includes the renovation project of the Bégude compressor station from 2025 for 78 M€, as well as 43 M€ in provisions over the period, corresponding to projects not identified at this stage;
- an increase in safety expenses (+ 36 M€ over the period, or +10%), those related to the environment (+ 21 M€ over the period, or +33%, due to programs to reduce methane emissions and deal with the presence of asbestos in its installations), and those related to vehicles and real estate (+ 22 M€ over the period, or +22%, notably to take into account the obligations related to the tertiary decree);
- a decrease in transmission continuity and gas quality expenses (-102 M€, or -38%), due to the end of major projects, such as strengthening of the network in Brittany;
- a decrease in expenses related to the information system (-31 M€, or -11%), with the end of some major projects to redesign the business IS, but an increase in expenses related to cybersecurity (+40 M€ over the period).

<u>CRE's analysis</u>

The main item with a sharp increase is that of expenses related to biomethane, an increase of 50% compared to ATRT7. The rest of the expenditure follows a stable trajectory and corresponds to an investment cycle without major reinforcements or significant development of the network.

In accordance with the incentive regulation scheme for capital expenditure (see paragraph 2.4.3), certain projects may be the subject of audits to define a target budget. This is notably the case for at least three projects (phase 2 of the Telester programme, renewal of the La Bégude compressor station, Gournay-Cuvilly link), whose estimated budgets are more than 20 M€ per GRTgaz and which are eligible for the incentive regulation scheme for major projects.

Off-grid spending is stable compared to the previous period and represents 91 M€ per year on average, or 20% of expenses over the period. They are eligible for the incentive regulations of non-infrastructure investments (see paragraph 2.4.3.3).

CRE does not make any changes to the investment trajectory planned by GRTgaz. 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 transport, operators' capital expenditure must be controlled as well as possible. CRE will monitor control of these expenses at the time of annual approval of the TSOs' investments, as specified by the provisions of articles L. 134-3 and L. 431-6 of the Energy Code.

Consequently, CRE retains the investment expenditure trajectory requested by GRTgaz for the ATRT8 tariff period:

In current M€	2024	2025	2026	2 027	ATRT8 annual average	ATRT7* annual average
Continuity of delivery and gas quality	47.9	39.5	38.2	37.4	40.7	66.2
Development of the main 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
SI	62,0	56,0	56,0	56,0	57,5	69,0
Outside network outside IS	40,8	35,2	28,6	28,8	33,3	24,2
TOTAL	**447.9**	**430.1**	**479.5**	**480.4**	**459.5**	**418.9**

*Average of investment programs carried out for 2020, 2021, 2022 and estimated 2023

3.1.4.2.2 Teréga

The trajectory of Teréga's capital expenditure over the ATRT8 period is up with average expenditure of 121 M€ per year over this period, whereas it was around 102 M€ per year during the ATRT7 period. This increase in expenditure is notably linked to the "security and maintenance" item, up 17.3 M€ over the period.

In particular, Teréga foresees:

- the increase in security and maintenance expenses (+69 M€ over the period, or + 22%). These mainly concern pipelines (+ 95 M€ over the period, or +42%), and result from the regional network pipeline renewal program planned by Teréga, with a dozen projects of more than 20 M€ already under study or which should be launched during the ATRT8 tariff period;
- the increase in R&D expenditure (+12 M€ over the period, or +113%);
- a decrease in IS-related expenses (-10 M€, or -22%), linked to Teréga's desire to focus on OPEX expenses for IS.

<u>CRE's analysis</u>

CRE observes that the trajectory requested by Teréga is up 19% compared to the previous period, mainly due to the increase in expenses related to the renewal of pipelines on the regional network. These investments must be compatible with the outlook for lower gas consumption, so as not to feed the risk of increased unit transport costs already identified. Similarly, some R&D investments may not be necessary for execution of the TSO's missions.

In accordance with the incentive regulation scheme for capital expenditure (see paragraph 2.4.3), certain projects may be the subject of audits to define a target budget. This is notably the case for at least six pipeline renewal projects on the regional network.

CRE does not make any changes to the investment trajectory foreseen by Teréga. 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 transport, operators' capital expenditure must be controlled as well as possible. CRE will monitor control of these expenses during the annual approval of TSO investments, provided for by the provisions of articles L. 134-3 and L. 431-6 of the Energy Code, in particular with regard to the network renewal and R&D projects mentioned above.

Consequently, CRE retains the following capital expenditure trajectory for Teréga for the ATRT8 tariff period:

In current M€	2024	2025	2026	2 027	ATRT8 annual average	ATRT7* annual average
Developments	2.1	0.1	1.7	3.2	1.7	1.8
Connections	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
SI	9.7	9.2	8.8	8.5	9.1	11.6
Outside network outside IS	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 programs carried out for 2020, 2021, 2022 and estimated 2023

3.1.4.3 Normative capital charges

3.1.4.3.1 GRTgaz

- Trajectory of normative capital charges

The table below presents the forecast trajectory of the RAB and the assets under construction (AuC) of GRT-gaz from 2024 to 2027:

Regulated assets base (RAB) and assets under construction (AuC)					
GRTgaz, in current M€	2024	2025	2026	2 027	ATRT8 an-nual average
RAB at 01/01/N	9 375.7	9 422.2	9 356.9	9 294.5	9 362.3
Service start-ups*	458.6	376.1	403.4	513.6	437.9
Amortisation	-594.5	-604.2	-604.3	-606.2	-602.3
Revaluations	182.5	162.8	138.5	118.5	150.6
RAB at 31/12/N	9 422.2	9 356.9	9 294.5	9 320.4	9 348.5
Fixed assets in progress (AuC)	450.6	403.3	468.7	532.9	463.9

*Investments entering the RAB minus projected asset exits

The forecast base of regulated assets breaks down as follows:

Regulated asset bases (RAB) as of 01/01/N	2024	2025	2026	2 027
GRTgaz	9 375.7	9 422.2	9 356.9	9 294.5
Pipes and connections	5 674.1	5 648.5	5 562.9	5 510.0
Compression	1 415.3	1 391.3	1 374.5	1 358.6
Delivery stations, expansion and metering	746.3	862.9	939.1	1 027.6
Real estate, construction, land	716.8	687.7	720.9	730.9
Others (hardware, tools, software, IS, etc.)	823.2	831.7	759.4	667.3

The table below details the forecast trajectory of GRTgaz's normative capital charges (CCN) from 2024 to 2027:

GRTgaz, in current M€	Average 20-22	2024	2025	2026	2 027	ATRT8 annual average
Depreciation of assets in service	523.7	594.5	604.2	604.3	606.2	602.3
Remuneration of assets in service	450.8	458.7	456.5	443.1	437.4	448.9
Compensation of AuC	12.0	12.6	11.3	13.1	14.9	13.0
Remuneration of subsidies	5.7	4.2	4.2	2.7	1.7	3.2
Coverage of small stranded costs	5.8	4.6	4.6	4.6	4.6	4.6
Tariff restatement	-1.0	-0.4	-0.4	-0.4	-0.4	-0.4
Total of normative capital charges Of which CCN "excluding infrastructure"	**997.0**	**1,074.3** 119.9	**1,080.4** 124.3	**1,067.4** 125.9	**1,064.5** 121.7	**1,071.6** 122.9

- Trajectory of normative capital charges "excluding infrastructure"

The table below details the specific trajectory of RAB, AuC and CCN for GRTgaz's "non-infrastructure" assets from 2024 to 2027, which are the subject of a specific regulation defined in 2.4.3.3 of the deliberation.

GRTgaz, in current M€	2022	2024	2025	2026	2 027	ATRT8 annual average
RAB at 01/01/N	*395.7*	*426.8*	*435.6*	*439.4*	*426.4*	*432.0*
Depreciation of assets in service	89.4	98.4	101.5	102.5	98.4	100.2
Remuneration of assets in service	16.9	19.0	20.4	21.4	21.3	20.5
Fixed assets in progress (AuC)	95.1	90.7	83.9	70.2	67.9	78.2
Compensation of AuC	2.5	2.5	2.3	2.0	1.9	2.2
Total "off-grid" CCNs	**108.8**	**119.9**	**124.3**	**125.9**	**121.7**	**122.9**

3.1.4.3.2 Teréga

- Trajectory of normative capital charges

The table below presents the forecast trajectory of the RAB and the assets under construction (AuC) of Teréga from 2024 to 2027:

Regulated assets base (RAB) and assets under construction (AuC)					
Teréga, in M€ current	**2024**	**2025**	**2026**	**2 027**	**ATRT8 annual average**
RAB at 01/01/N	1 862.0	1 901.3	1 943.2	2 007.8	1 928.6
Service start-ups*	94.7	96.9	125.7	155.8	118.3
Amortisation	-89.1	-87.7	-89.9	-92.8	-89.9
Revaluations	33.6	32.8	28.8	25.0	30.1
RAB at 31/12/N	1 901.3	1 943.2	2 007.8	2 095.9	1 987.0
Assets under Construction (AuC)	98.1	121.1	143.3	143.5	126.5

*Investments entering the RAB

The forecast base of regulated assets breaks down as follows:

Regulated asset bases (RAB) as of 01/01/N	2024	2025	2026	2 027
Teréga	1 862.0	1 901.3	1 943.2	2 007.8
Pipes and connections	1 374.2	1 406.5	1 436.3	1 504.8
Compression	231.4	227.5	226.6	221.9
Delivery stations, expansion and metering	124.7	134.3	140.9	145.8
Real estate, construction, land	48.8	48.2	50.2	49.3
Others (hardware, tools, software, IS, etc.)	83.0	84.8	89.2	86.0

The table below details the forecast trajectory of Teréga's normative capital charges (CCN) from 2024 to 2027:

Teréga, in M€ current	Average 20-22	2024	2025	2026	2 027	ATRT8 annual average
Depreciation of assets in service	78.1	89.1	87.7	89.9	92.8	89.9
Remuneration of assets in service	86.3	92.2	94.5	93.4	96.9	94.2
Compensation of AuC	2.7	2.7	3.4	4.0	4.0	3.5
Remuneration of subsidies	1.5	0.5	0.5	0.5	0.5	0.5
Coverage of small stranded costs	0.3	0.3	0.3	0.3	0.3	0.3
Tariff restatement	-0.2	-0.2	-0.2	-0.2	-0.2	-0.2
Total of normative capital charges	**168.5**	**184.6**	**186.1**	**187.9**	**194.2**	**188.2**
Of which CCN "excluding infrastructure – real estate and vehicles"		5.5	5.2	6.0	6.3	5.7
Of which CCN "information system"		14.6	12.8	11.7	11.0	12.5

- Trajectory of normative capital charges "excluding infrastructure"

The table below details the specific trajectory of RAB, AuC and CCN under the assets "excluding infrastructure – real estate and vehicles" of Teréga from 2024 to 2027, which are the subject of a specific regulation defined in 2.4.3.3 of the deliberation.

Teréga, in M€ current	2022	2024	2025	2026	2 027	ATRT8 annual average
RAB at 01/01/N	*35.4*	*38.6*	*39.7*	*44.2*	*44.6*	*41.8*
Depreciation of assets in service	3.4	3.7	3.4	3.9	4.2	3.8
Remuneration of assets in service	1.5	1.6	1.7	2.0	2.0	1.8
Assets under Construction (AuC)	4.6	3.0	4.4	2.4	2.5	3.1
Compensation of AuC	0.1	0.1	0.1	0.1	0.1	0.1
Total CCNs "excl. networks – real estate and vehicles"	**5.1**	**5.5**	**5.2**	**6.0**	**6.3**	**5.7**

- Trajectory of expenses related to IS

The table below details the specific trajectory of Teréga's IS-related expenses from 2024 to 2027, which are the subject of a specific regulation defined in 2.4.3.3 of the deliberation.

Teréga, in M€ current	2022	2024	2025	2026	2 027	ATRT8 annual average
RAB at 01/01/N	*44.3*	*33.8*	*30.8*	*29.1*	*27.9*	*30.4*
Depreciation of assets in service	14.5	13.0	11.1	10.0	9.4	10.9
Remuneration of assets in service	1.9	1.5	1.5	1.5	1.5	1.5
Assets under Construction (AuC)	5.9	5.9	5.7	5.5	5.5	5.7
Compensation of AuC	0.2	0.2	0.2	0.2	0.2	0.2
Total "off-grid – IS" CCNs	**16.5**	**14.6**	**12.8**	**11.7**	**11.0**	**12.5**

Teréga, in M€ current	2024	2025	2026	2 027	ATRT8 annual average
IS commissioning	*9.7*	*9.3*	*8.9*	*8.6*	9.1
IS OPEX	14.9	15.3	15.7	15.9	15.5
IS TOTEX	**24.6**	**24.5**	**24.6**	**24.5**	**24.6**

3.1.5 CRCP as at 31 December 2023

The overall balance of the CRCP is calculated before the final closure of the annual accounts. Thus, it is equal to the amount to be paid or deducted from the CRCP (i) for the past year, on the basis of the best estimate of annual expenses and revenues (known as the estimated CRCP), and (ii) for the previous year, by comparison between the expenses and revenues realised and the estimate that had been done a year earlier (known as the final CRCP), to which is added, if applicable, the balance of the CRCP not cleared for previous years.

The amount to be paid or deducted from the CRCP on 31 December 2023 is calculated by CRE, for years 2022 and 2023, according to the deviation from the realised or its estimate, for each item concerned, from the reference amounts defined in Appendix 8 of the ATRT7 deliberation. The share of this difference paid to the CRCP is set in the ATRT7 deliberation.

3.1.5.1 GRTgaz

In its updated tariff file, GRTgaz estimated the CRCP balance as at 31 December 2023 at -56.7 M€, to be returned to the users of the transport network[25]. This balance is the sum of the following:

- the updated remainder of the previous CRCP (i.e. - 126.7 M€);
- the updated difference between the estimated balance for 2022 and the final 2022 CRCP (i.e. + +68.0 M€);
- the estimated CRCP for 2023 (i.e. +2.1 M€).

The CRCP at 31 December 2023 estimated by CRE in the calculation of GRTgaz's allowed revenue totals -59.0 M€, which will be deducted from the charges to be covered. This balance is the sum of the following:

- the updated remainder of the previous CRCP (i.e. - 126.7 M€);
- the updated difference between the estimated balance for 2022 and the final 2022 CRCP (i.e. +64.7 M€), which is mainly due to lower capacity sales revenue (including surpluses related to auction revenues) than estimated (+47.7 M€);

[25] By agreement, with regard to the CRCP, a "-" sign corresponds to an amount to be returned to users, and a "+" sign to an amount to be returned to the operator

- the estimated CRCP for 2023 (i.e. + 3.0 M€), which is mainly explained by:
  - higher than estimated capacity sales revenue (including surpluses related to auction revenues) (- 285.4 M€);
  - higher than expected expenses in terms of energy (+162.5 M€), capital expenses (+63.4 M€), the conversion of H gas into B gas (+32.4 M€) and congestion management (+21.2 M€)
  - revenue from services for third parties less than expected (+10.1 M€).

Congestion charges for 2023 included by CRE in the CRCP correspond to the charges observed as of 4 December 2023. When calculating the final CRCP for 2023, CRE will examine the coverage rate of these charges with regard to effectiveness of the measures implemented by the TSOs to limit congestion on the French transport network.

The difference between the request of GRTgaz and the level adopted by CRE (-2.4 M€) is mainly explained by an update of capacity sales revenue at Obergailbach in 2023 (-4.4 M€), the inclusion of an update by GRTgaz of its energy expense assumptions (+5.5 M€), and the inclusion of assumptions different from those of GRTgaz with regard to congestion management expenses for 2023 (-1.5 M€).

GRTgaz – CRCP at 31 December 2023 (M€)

GRTgaz	Updated amounts for year 2022	Updated amounts for year 2023[26]
Routing revenue covered at 100 %	+ 52.0	- 223.4
Routing revenue covered at 80 %	- 4.3	- 62.0
Normative capital charges	+ 3.3	+ 63.4
Energy charges	+ 4.2	+ 162.5
Inter-operator transit contract	0	- 1.5
OPEX variance due to inflation	- 0.1	+ 5.0
Service quality	+ 0.1	+ 1.5
Charges for the H-B conversion service	- 0.1	+ 32.4
Income from services for third parties related to major development projects	+ 5.5	+ 10.1
Costs of handling congestion	+ 0.3	+ 21.2
Connection of biomethane units	+ 1.0	- 2.0
Inter-operator transfer (ITC)	0	+ 6.8
Charges of consumables	- 1.3	+ 2.2
Payment GRD-> GRTgaz (Opex associated with backhauls)	+ 0.2	0
Contracts with adjacent operators	+ 3.8	- 13.1
Total	**+ 64.7**	**+3.0**
Remainder of previous CRCP updated	**- 126.7**	
CRCP balance as at 31 December 2023	**- 59.0***	

*The amount of the CRCP balance as of 31 December 2023 will be smoothed over 4 years and integrated into the allowed revenue over the ATRT8 period. Since the amount for deviations for 2023 are provisional, the final value will be included in the CRCP balance as of 31 December 2024.

3.1.5.2 Teréga

In its updated tariff file, Teréga estimated the CRCP balance as of 31 December 2023 at -2.4 M€, to be returned to the operator. This balance is the sum of the following:

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

[26] The CRE will calculate the deviations from the reference trajectory for R&D expenses over the ATRT8 period once the 2023 expenses are definitively known.

- the estimated CRCP for 2023 (i.e. -3.3 M€).

At this stage, the CRCP at 31 December 2023 estimated by CRE totals -3.2 M€, to be returned to network users. This balance is the sum of the following:

- the updated difference between the estimated balance for 2022 and the final 2022 CRCP (i.e. +0.9 M€), which is mainly due to lower capacity sales revenue (including surpluses related to auction revenue) than estimated (+0.5 M€);
- the estimated CRCP for 2023 (i.e. + -4.1 M€), which is mainly explained by:
    - the restatement of Teréga's operating expense trajectory in order to extract inspection and rehabilitation expenses, which are now included in the TSO's capital expenses (- 7.8 M€);
    - expenses related to the inter-operator payment to GRTgaz that were less than expected (-6.5 M€);
    - higher than expected expenses for energy (+ 2.3 M€), capital expenses (+ 8.6 M€) and congestion management (+ 2.5 M€);
    - revenues from third-party services and connections of biomethane production units that were higher than expected (-4.6 M€);
    - taking into account the stranded costs related to part of the study expenses of the Vianne project (+0.7 M€), which had been approved by CRE[27].

Congestion charges for 2023 included by CRE in the CRCP correspond to the charges observed as of 4 December 2023. When calculating the final CRCP for 2023, CRE will examine the coverage rate of these charges with regard to effectiveness of the measures implemented by the TSOs to limit congestion on the French transport network.

The difference between Teréga's request and the level adopted by CRE (-0.8 M€) is mainly explained by the fact that the assumptions taken into account were different from those of Teréga with regard to the expenses related to congestion management for 2023 (-1.3 M€), and the fact that part of Teréga's request for coverage of 1.3 M€ of stranded costs was not taken into account. The stranded costs not retained by CRE correspond to either education expenses that had not been approved by CRE, or to stranded costs that fell within the scope of the trajectory of recurring and predictable stranded costs for ATRT7.

[27] Deliberation of the Energy Regulation Commission of 22 July 2020 on the implementation balance of the 2019 investment programme and approving Teréga's revised 2020 investment programme (transport)

Teréga– CRCP at 31 December 2023 (M€)		
Teréga	**Updated amounts for year 2022**	**Updated amounts for year 2023[28]**
Routing revenue covered at 100 %	+ 1.0	- 11.4
Routing revenue covered at 80 %	- 0.5	+ 11.7
Normative capital charges	+ 0.1	+ 8.6
Energy charges	+ 0.1	+ 2.3
Inter-operator transit contract	0	+ 1.5
OPEX variance due to inflation	0	- 7.3
including restatement related to the classification of inspection and rehabilitation expenses		- 7.8
Service quality	+ 0.1	+ 0.7
Income from services for third parties related to major development projects	+ 0.2	- 2.3
Costs of handling congestion	+ 0.0	+ 2.5
Connection of biomethane production units	+ 0.1	- 2.3
Connection of GNV stations	0	+ 0.1
Inter-operator transfer (ITC)	- 0.2	- 6.5
Contracts with adjacent operators	0	- 2.3
Stranded costs	0	+0.7
Total	**+ 0.9**	**-4.1**
Remainder of previous CRCP updated	**0**	
CRCP balance as at 31 December 2023	**- 3.2***	

*The amount of the CRCP balance as of 31 December 2023 will be smoothed over 4 years and integrated into the allowed revenue over the ATRT8 period. Since the amount for deviations for 2023 are provisional, the final value will be included in the CRCP balance as of 31 December 2024.

3.2 Provisional capacity subscriptions

3.2.1 Request of operators

3.2.1.1 GRTgaz

In its tariff file, GRTgaz presented a subscription trajectory based on the following forecasts:

- the gradual and significant decline in long-term subscriptions at IPs, at entry (Dunkirk, Obergailbach and Virtualys) and exit (Oltingue);
- large and stable entry subscriptions from LNG terminals consistent with the sharp increase in LNG flows;
- the gradual decline in exit subscriptions from the main network and on the regional network caused by a reduction in peak consumption (under the double effect of energy conservation efforts and update of the climate reference used to calculate peak consumption);
- storage capacities fully subscribed.

This demand implies an average annual decrease of 4.6% in subscriptions on the main network, and an average annual decrease of 4.3% on the operator's regional network.

[28] The CRE will calculate the deviations from the reference trajectories for Teréga's R&D charges and "TOTEX" experimentation over the ATRT8 period once the 2023 expenses are definitively known.

Since the public consultation, GRTgaz has presented a new capacity subscription trajectory, notably reflecting changes concerning the update of the climate reference system. This new request leads to the subscription trajectory below:

% change in capacity subscriptions per year	2024	2025	2026	2 027	Annual average change
Main Network	-4.9%	-4.1%	-4.6%	-8.0%	-4.6%
Regional Network	-1.3%	-2.0%	-3.6%	-3.3%	-2.5%

3.2.1.2 Teréga

Teréga presented a subscription trajectory based on the following forecasts:

- structurally oriented flow assumptions from south to north;
- a sharp increase in entries to Pirineos over the entire period;
- the gradual decline in exit subscriptions from the main network and on the regional network caused by a reduction in peak consumption (under the double effect of energy conservation efforts and update of the climate reference used to calculate peak consumption);
- storage capacities fully subscribed.

% change in capacity subscriptions per year	2024	2025	2026	2 027	Annual average change
Main Network	-1.3%	-0.4%	-2.0%	-4.5%	-2.1%
Regional Network	-2.0%	-3.2%	-3.3%	-2.9%	-2.9%

3.2.2 CRE's analysis

In the public consultation, CRE indicated that it was in line with the majority of the forecasts retained by the TSOs, while considering that certain assumptions were conservative. As such, CRE considered a number of adjustments:

- an increase in the TSO input capacity assumptions by approximately 125 GWh/d/year (+5% compared to the TSO assumptions), in order to retain capacity levels consistent with the balance of the physical assessment of the gas system;
- an increase in downstream subscriptions, consistent with the ADEME S3 scenario which was used as part of the study on the future of gas infrastructures conducted by CRE.

The majority of respondents to the public consultation did not express an opinion on the level of subscriptions, sometimes indicating high uncertainties related to the geopolitical context. Some suppliers consider, like CRE, that the requests of the TSOs are too conservative.

In its response to the public consultation, GRTgaz asks to reduce the assumptions of exit subscriptions for Obergailbach and entry subscriptions for Dunkirk. In addition, a supplier requests to increase the assumption of exit subscriptions for Oltingue. Finally, Teréga requests to reduce its assumption of entry subscriptions to Pirineos, due to the uncertainties relating to this level of subscriptions.

CRE retains a lower level of exit subscriptions for Obergailbach of 20 GWh/d/year on average over the ATRT8 period compared to the public consultation, and a higher level of exit subscriptions in Oltingue of 10 GWh/d/year on average over the ATRT8 period.

Finally, CRE observes that the new downstream subscription assumptions of GRTgaz and those of Teréga are more consistent with the ADEME S3 scenario. It therefore retains these assumptions. The table below shows the average estimated capacity subscriptions retained by CRE over the ATRT8 period.

MWh/d/year	Entry Capacities subscribed	Exit Capacities subscribed
IP Virtualys	188,500	19,000
IP Taisnières B	[confidential]	0
IP Dunkirk	550 000	0
IP Obergailbach	218,200	30,000
IP Oltingue	0	200,000
IP Pirineos	252,800	54,000
PITTM Dunkirk	370,000	
PITTM Fos	407,300	
PITTM Montoir	382,000	
PITTM Le Havre	110 000	
PITS Northwest	378,900	213,300
PITS Atlantique	637,500	312,500
PITS Southeast	644,800	109,800
PITS North B	77,900	42,200
PITS Northeast	176,000	125,000
PITS Southwest	556,400	300,800
Output to regional network		*3,870 000*

3.3 Evolution trajectory of the allowed revenue of natural gas transmission system operators

3.3.1 Allowed revenue over the period 2024-2027

3.3.1.1 GRTgaz

The allowed revenue of GRTgaz for the ATRT8 period breaks down as follows:

GRTgaz, in M€$_{current}$	2023 Smoothed allowed revenue	2024	2025	2026	2 027
Net operating expenses		1,024.9	930.8	892.9	864.2
Normative capital charges		1,074.3	1,080.4	1,067.4	1,064.5
Clearance of ATRT7 CRCP balance		-15.6	-15.6	-15.6	-15.6
Allowed revenue	**1,724.6**	**2,083.6**	**1,995.6**	**1,944.7**	**1,913.0**
Annual change	-	*+20.8%*	*-4.2%*	*-2.6%*	*-1.6%*

Excluding smoothing effects, the expenses to be covered retained by CRE for GRTgaz result in an increase of +20.8% of the allowed revenue between 2023 and 2024, then a decrease of -2.8% on average per year over the ATRT8 period.

3.3.1.2 Teréga

Teréga's allowed revenue for the ATRT8 period breaks down as follows:

Teréga, in M€$_{current}$	2023 Smoothed allowed revenue	2024	2025	2026	2 027
Net operating expenses		76.6	77.6	79.3	80.5
Normative capital charges		184.6	186.1	187.9	194.2
Clearance of ATRT7 CRCP balance		-0.8	-0.8	-0.8	-0.8
Allowed revenue	**269.2**	**260.3**	**262.9**	**266.4**	**273.9**
Annual change	-	*-3.3%*	*+1.0%*	*+1.3%*	*+2.8%*

Excluding smoothing effects, the expenses to be covered retained by CRE for Teréga result in a decrease of -3.3% of the allowed revenue between 2023 and 2024, then an increase of +1.7% on average per year over the ATRT8 period.

3.3.2 Smoothed allowed revenue over the period 2024-2027

As specified in section 2.3.4, to calculate the price evolution on 1 April 2024 and then during each year of the ATRT8 period, CRE decides to smooth the evolution of the operators' estimated allowed revenue. This smoothing implies evolution of the unit gas transmission tariffs of the "initial market" type, then annual evolution corresponding to inflation. This has no impact on the charges recovered by the TSOs over the duration of the ATRT8 tariff but avoids significant price changes in opposite directions from one year to the next.

The tables presented below are developed on the basis of the tariff grids determined by the tariff structure and presented in part 4.

The tariff grid resulting from the structure of the main network implies an imbalance in the distribution of subscription revenues between the two TSOs in relation to their respective charges associated with the main network, of approximately 40 M€ over the tariff period, to the disadvantage of Teréga. As indicated in section 2.8.1, CRE replaces the transfer from Teréga to GRTgaz implemented at the time of the merger of the zones (and calculated according to the exit subscriptions for the Pirineos IP) with a transfer from GRTgaz to Teréga, allowing each of the two operators to cover their respective expenses associated with the main network. This payment is also included in the smoothed allowed revenue presented in the table below.

Thus, the allowed revenues of GRTgaz and Teréga for the 2024-2027 period are defined as the sum of the following:

- net operating expenses (see paragraph 3.1.3);
- normative capital charges (see paragraph 3.1.4);
- clearance of the balance of the CRCP calculated on 31 December 2023 (see paragraph 3.1.5);
- inter-operator payment financial flow resulting from the equalisation of the tariff terms of the main network (see paragraph 2.8.1);
- the smoothing term allowing a price evolution corresponding to the conditions defined in section 2.3.4.

3.3.2.1 GRTgaz

in M€ current	2023	2024	2025	2026	2 027
Allowed revenue		2,083.6	1,995.6	1,944.7	1,913.0
ATRT8 inter-operator payment		0.0	0.0	8.0	32.1
ATRT8 smoothing term		-107.0	71.8	63.3	-21.5
Smoothed allowed revenue	**1,724.6**	**1,976.6**	**2,067.4**	**2,016.0**	**1,923.7**
Annual change		*+14.6%*	*+4.6%*	*-2.5%*	*-4.6%*

3.3.2.2 Teréga

in M€ current	2023	2024	2025	2026	2 027
Allowed revenue		260.3	262.9	266.4	273.9
ATRT8 inter-operator payment		0.0	0.0	-8.0	-32.1
ATRT8 smoothing term		4.4	8.3	2.0	-18.0
Smoothed allowed revenue	**269.2**	**264.8**	**271.2**	**260.4**	**223.8**
Annual change		*-1.6%*	*+2.4%*	*-4.0%*	*-14.0%*

4. Structure of the tariff for use of natural gas transmission networks

4.1 Network representation and scope covered by the ATRT8 tariff

The transport network is attached to a single market area, the *Trading Region France* (TRF).

The transport network consists of, on one hand, the main network and, on the other hand, the regional network. Users of the GRTgaz and Teréga networks use the gas transmission network for several purposes: flows to cross-border outlets, i.e. bringing gas into these networks to transport it to another country, and flows to internal outlets, i.e. transporting gas intended for consumption in the national territory. Users can also make use of underground natural gas storage.

Moreover, in the north of France, there is a "zone B", supplied with gas with low calorific value (known as "gas B"), whose network is physically separated from the rest of the French transport network.

The French natural gas transmission network in 2023

CRE sets natural gas transmission tariffs so as to avoid any cross-subsidisation between the different categories of users of the transmission networks, notably between users transporting gas to cross-border outlets and those supplying domestic consumption. It also ensures that there is no cross-subsidy between the two network categories, main and regional, ensuring that the revenues collected for each correspond to the expenses that are generated by their use.

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

- Main Network

The main network is composed of network elements that connect the interconnection points with (i) adjacent transport networks, (ii) exits to the regional network, (iii) LNG terminals and (iv) storage facilities. It stretches over 9,000 km. Flows are generally bi-directional.

The tariff structure of the main network is based on an entry-exit tariff principle by market place. Gas can be bought and/or sold directly on the marketplace or Gas Exchange Point (PEG). In this case, the user pays the tariff terms specific to the PEG.

Users can bring gas into France by means of interconnections via pipelines (Network Interconnection Point, or IP, and Virtual Interconnection Point, or PIV) or via LNG terminals (Transport Terminal Interface Points, or PITTM) and, for this purpose, comply with the terms of entry at these points. These terms are identical regardless of the destination of the gas (cross-border exit, storage or national consumption).

Gas exits the main network at different points, depending on its destination:

- to bring gas to a neighbouring country, users pay an exit term to the IP or PIV;
- to supply national consumption, users pay an exit term to the regional network.

Underground natural gas storage is located on the main network. Network users make use of it by fulfilling entry and exit terms at Transport Storage Interface Points (PITS).

The tariff principles of the main network retained by CRE are described in 4.2 of this deliberation.

Regional Network

The regional network is composed of the network elements that allow gas to be transported from the main network to the final customers or to the distribution networks. It stretches for nearly 28,000 km. The flows generally move in one direction.

The supply of each delivery point requires the subscription, on one hand, of routing capacities and, on the other hand, of delivery capacities. There are 3 types of delivery points:

- transmission-distribution interface points (PITD) that represent the interface between the transmission network and one or more outlets to the distribution network;
- sites of industrial consumers directly connected to the transport network;
- regional network interconnection points (RIP) that allow delivery to foreign regional networks.

The principles of regional network tariffs adopted by CRE are described in 4.3 of this deliberation.

- Storage compensation

Introduced in the ATRT tariff in 2018, in the context of regulation of the regime of access to the natural gas storage infrastructure, storage compensation corresponds to the difference between the estimated allowed revenue of natural gas storage operators and the revenue they receive directly, mainly in the context of the auctioning of storage capacities. It is collected by the TSOs, which pay it back to the storage operators. The principles of collection of the storage compensation by CRE are presented in part 5 of this deliberation.

4.2 Tariff structure of main network

4.2.1 Thematic consultation workshop

A consultation workshop on evolution of the tariff terms structure of the main gas transmission network was organised by CRE on 4 May 2023. This workshop was attended by 70 participants.

During the workshop, CRE presented the challenges of the ATRT8 in connection with the end of long-term contracts, the reorganisation of flow patterns in Europe and the decrease 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 evolution:

- an "A" scenario, using the structure of the ATRT7, for comparison;
- a "B" scenario, taking into account changes in flow patterns observed since the decrease in European supplies of Russian gas;
- a "C" scenario, taking into account the changes in flow patterns observed since the decrease in European supplies of Russian gas, as well as internal congestion of the French network in winter.

Overall, CRE's analyses did not encounter any opposition in principle during the workshop, although some participants questioned the consequences in terms of evolution of the tariff level and the attractiveness of the French market compared to other European markets. Following the workshop, CRE received additional contributions, some questioning certain flow scenarios presented by CRE, and others drawing the attention of CRE to the maintenance of TSOs affecting the availability of capacities.

Most stakeholders expressed support for Scenario B.

CRE decides to retain this scenario for the structure of the main network for the ATRT8. In fact, this scenario is the one comprising the assumptions of the most justifiable and verifiable flow diagrams representing use of the network and, moreover, allows better distribution of the tariff increase on the various entry and exit points of the main natural gas transmission network.

4.2.2 Calculation methodology of reference prices

4.2.2.1 Distribution of the costs of the main network, the regional network and the storage compensation

4.2.2.1.1 Classification of services rendered by TSOs

Article 4 of the Tariff Network Code distinguishes between services provided by TSOs, transport services[29] (*Transmission services*), and those that are ancillary services[30] (*Non-Transmission services*). This article specifies that *"revenue associated with transport services shall be recovered by capacity-based transport tariffs*" and that "*revenue from ancillary services shall be recovered by ancillary service tariffs applicable to an ancillary service. ".* The Tariff Network Code specifies that the tariffs for ancillary services comply with the following principles: *"a) they reflect costs, they are non-discriminatory, objective and transparent; b) they are incurred by the beneficiaries of an ancillary service with the aim of minimising cross-subsidies between network users. "*

[29] "Transmission Services" means the regulated services provided by the Transmission System Operator in the Input-Output System for the purpose of transmission.
[30] "Ancillary services" means regulated services other than transmission services and other than services governed by Regulation (EU) no. 312/2014, which are provided by the transmission system operator

The services rendered by the TSOs have been classified as follows in the ATRT7 tariff:

- transport services: the services rendered by TSOs on the main network. Tariffs on this network are set up according to an input-output model and are based on capacity and distance;
- related services:
  - the services rendered by TSOs on the regional network. This network is not in an input-output model insofar as there is no input term. However, the tariffs for this network notably take into account the distance from the main network. In addition, as these networks are used only by domestic customers, 100% of the costs are allocated to them. Any cross-subsidisation between flows to cross-border exits and flows for domestic consumption is, therefore, avoided;
  - storage compensation: collected by TSOs from their customers and transferred to storage operators, this compensation is not intended to reflect the costs of a service provided by the TSO, but to compensate the allowed revenue of storage operators in accordance with article L. 452-1 of the Energy Code.

Respondents to the public consultation on the ATRT8 tariff are in favour of maintaining the classification of services rendered by TSOs in ATRT8.

Consequently, and given that no significant change in the structure or scope of these services occurred during the period of ATRT7, CRE decided to renew the classification of the services rendered by the TSOs of ATRT8.

4.2.2.1.2 General principles of the reference method

In past tariff periods, the ATRT tariff was set to meet several objectives, including:

- non-discrimination: network users incur the same charges for the same network use (the level of tariff terms that users pay at a given point at the entrance and exit of the French network remains independent from use of the point in question);
- cost reflection: the tariff aims to reflect costs and send a relevant economic signal to network users through, on one hand, the use of relevant cost drivers (including capacity and distance) to set tariff terms and, on the other hand, the launch of *Open seasons* for long-term capacity reservations to ensure the financing of network developments;
- acceptability of changes: tariff changes must be progressive and structural changes in the tariff must be duly justified and be the subject of consultation with market participants so that all interested parties have sufficient visibility, as necessary, for proper functioning of the market.

CRE's methodology for calculating reference prices is based on the observation that a large majority of TSO costs are fixed costs that remain constant in the short term, even if network use varies (they represent about 90% of total costs in France). For the most part, these costs are directly related to the level of investments and are, therefore, closely linked to the investment strategy. This investment strategy is developed taking into account the limits of the networks that need to be raised in order to guarantee the main scenarios and flow configurations.

In principle, for the tariff paid by each network user to perfectly reflect costs, they must be distributed among the network users generating the investment needs. However, as the French transport network is complex and largely interconnected, it is difficult to reflect costs perfectly. A compromise must be found in order to maintain a sufficiently simple and stable transport tariff. To this end, CRE notably defines relevant flow scenarios, the definition of which is described in the following paragraphs.

4.2.2.1.3 Distribution of costs of the main network, regional, of storage compensation costs and link to relevant flow scenarios

The costs related to the transmission network are distributed so as to avoid any cross-subsidisation between the different categories of network users:

- the costs of the main network (~ 1,000 M€/year) are considered as costs associated with transport services[31] and, therefore, allocated to both categories of network users (users transporting gas to cross-border outlets and those supplying domestic consumption);

[31] As defined by the Tariff network code

- the costs of the regional network (~ 1,200 M€/year) are considered as costs associated with ancillary services[32], allocated only to users supplying national consumption, that are the only users;
- storage compensation costs (~ 400 M€/year over the period 2020-2023) are considered as ancillary service costs, allocated to national consumption.

In the ATRT7 tariff, the above cost allocation was closely linked and consistent with the definition of the relevant flow scenarios used to allocate the costs of the main network among the different categories of network users. In fact, it is the flow scenarios adopted by CRE in its methodology that made it possible to allocate the costs of the regional network and storage compensation to national consumers only:

- with regard to the regional network: the flow scenarios adopted by CRE only took into account the distance to reach the exit of the main network and not that which makes it possible to reach the final consumer by crossing the entire regional network. Therefore, CRE has chosen to allocate the costs of the regional network to only domestic consumption, and the calculated distance to feed domestic consumption is reduced accordingly;
- with regard to storage compensation: filled gas storage facilities benefit all network users, including users transporting gas to cross-border outlets, through a higher level of security of supply. However, the storage compensation is only collected from national consumers because CRE considers that they are nevertheless the main beneficiaries of storage.

For ATRT8, the majority of respondents to the public consultation are in favour of maintaining the distribution of costs of the main network, regional and storage compensation that were in effect during ATRT7.

Given the feedback to the public consultation, CRE decided to maintain the distribution of costs of the main and regional networks and storage compensation in the ATRT8.

4.2.2.1.4 Balance between costs and revenues that can be allocated to the main network and the regional network

From implementation of the first gas transmission tariffs, CRE aimed to ensure the balance, for each TSO, on one hand between the charges that are applied to the main network and the revenues generated by its operation and, on the other hand, between the charges that are applied to the regional network and the revenues generated by its operation.

In its public consultation, CRE foresaw maintaining, for the ATRT8 tariff, the principle of balance, on average, over the tariff period of charges and revenues of the main and regional networks.

Consequently, CRE asked the TSOs to distribute their charges between those relating to the main network and those relating to the regional network. This distribution is based on the following two principles:

- capital expenditure and the majority of operating expenses are directly attributable to one of the networks by the TSOs and are, therefore, allocated to them;
- for a minor part of the operating expenses, the nature of which is too general to allow direct allocation (administrative costs, for example), the TSOs apply a distribution key, generally corresponding to a distribution in proportion to the kilometres of the network.

In application of these principles, over the ATRT8 period, the TSOs forecast the distribution of the following charges, in the France network:

	France Network	
	% of main network charges	% of regional network charges
Average ATRT8	46%	54%

All respondents to the public consultation expressed support for the principle of balance, on average, over the tariff period of charges and revenues of the main and regional networks.

Accordingly, CRE decides that the level of tariff terms will be set in the ATRT8 tariff such that the revenues collected on the main network will represent about 46% of the total revenues, and those collected on the regional network will represent about 54% of the total revenues.

[32] As defined by the Tariff network code

4.2.2.2 Methodology for determining tariff terms for general transport

4.2.2.2.1 Main tariff principles of the main network

- **Tariffs by capacity**

In the ATRT7 tariff, the gas transmission tariff was based on a tariff that was 100% dependent on the subscribed capacity. In other words, shippers reserve capacities for which they pay regardless of how they use them.

This tariff method is consistent with the Tariff Network Code, which provides, in article 4, that revenue associated with transport services is recovered by transport tariffs based on capacity. This tariff method notably makes it possible to take into account the positive effect that predictable and stable sites have for the gas system, particularly in terms of limiting investments. Thus, for the same consumption, the supplier of a temperature-sensitive customer subscribes more capacity in order to cover the peak consumption, which can be far from the average consumption.

CRE's inclination to maintain this principle of a tariff based 100% on capacity received a favourable opinion from all contributors to the public consultation.

Consequently, CRE decides to maintain the principle of tariffs based 100% on capacity as subscribed for ATRT8.

- **Entry-exit system**

In the ATRT7 tariff, the tariff structure of the main network was based on a principle of entry-exit. This principle allows network users to separately reserve their network entry and exit capacities[33] and, thus, to be able to transport gas between the points of their choice. The tariff terms that users pay, respectively, at the entrance and exit of the French network are independent of the destination and origin of the gas.

This input-output tariff principle ensures that tariffs applicable to network users are non-discriminatory and set separately for each entry/exit point of the transmission network.

All respondents expressed support for this entry-exit system.

Consequently, CRE decides to renew this entry-exit tariff system for the ATRT8 tariff.

- **Harmonisation of GRTgaz and Teréga tariff terms**

The ATRT7 tariff provided for the harmonisation of a number of tariff terms at the national level. Thus, the tariff terms for entry to the IPs of Dunkirk, Virtualys, Obergailbach, Oltingue and Pirineos are identical. This is also the case for the tariff terms for entry to the PITTMs of Dunkirk, Montoir, Fos and Le Havre. Aligning these terms gives shippers the opportunity to choose the most competitive source of supply.

In addition, the terms of exit from the main network to the GRTgaz and Teréga regional networks are aligned with each other.

The same applies to tariffs at PITS (Transport Storage Interface Point) on the Teréga and GRTgaz networks, with the exception of the North-East and Atlantic PITS tariffs, for which a 100% discount was implemented on 1 April 2023 in[34] order to facilitate the subscription of storage facilities and guarantee the safety of supply while market conditions were deteriorating.

In its public consultation, CRE foresaw renewing these principles for ATRT8, with the exception of the 100% discount applied to the North-East and Atlantic PITS, considering that the circumstances no longer justified this specific treatment.

All respondents were in favour of maintaining harmonisation of the tariff terms of the main network. A majority of respondents are also in favour of removing the 100% discount, and only two stakeholders are against it because they believe that this would reduce the attractiveness of storage.

Given the feedback to the public consultation, CRE decided to maintain this principle of harmonisation of tariff terms for ATRT8. CRE also decides to apply the same discount to all PITS (including the North East and Atlantic PITS). In fact, market conditions on storage facilities have improved and now make it possible to

[33] In an input-output system, users reserve their input and output capacities separately and the tariff terms they pay respectively for entries and exits from the network are independent of the destination and origin of the gas. The CRE stresses that this concept of input-output system must not be opposed to the objective of cost reflection. Thus, the entry and exit tariffs can reflect the costs of using the network, i.e. the costs associated with the probable combinations of entries and exits based on the reservations of all users.
[34] Deliberation of the Energy Regulation Commission of 31 January 2023 deciding on the annual evolution of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga on 1 April 2023

ensure a high level of subscription and filling of storage facilities. Since 2022, storage operators have been able to set their auction dates more flexibly[35] when market conditions are favourable.

- **Distribution of costs and revenues between entry points and exit points of the main network**

In addition to seeking a balanced distribution of revenues and charges between the main and regional networks, the distribution of revenues must also be approached from the perspective of sharing between points of entry and points of exit on the main network.

In France, the input/output revenue ratio, calculated from the capacities subscribed at the various points of entry and exit and the tariff terms in effect on 1 April 2023, was 34/66 in 2023.

The current distribution rate is the result of the presence in France of significant storage capacities to be able to make it through the winter peak. Thus, the capacities subscribed by shippers entering the French transport network are significantly lower than the capacities subscribed for the exit.

The distribution of revenues at 50-50 is shown in the Tariff network code only as an indication. This distribution is not relevant in a country like France that has significant storage capacities.

The majority of stakeholders that responded to the public consultation are in favour of maintaining this ratio. Some stakeholders believe that it may be necessary to allocate a smaller share of costs to entries. According to them, LNG will play an essential role for the security of supply, and tariffs that are too high at LNG terminal entrances would be detrimental to the French market.

CRE considers that the change in the entry/exit distribution would lead to an excessive increase in the tariff terms of delivery to consumers and the tariff terms of cross-border exit.

Consequently, CRE decided to renew the entry-exit revenue ratio to 34/66 for ATRT8:

Breakdown by type of points as %	France
Entry points (IP, PITTM)	34%
Exit points (IP exits and exits to the regional network)	66%

4.2.2.2.2 Method of calculating the tariff terms of the main network

a) Calculation steps for reference prices

As foreseen in the public consultation, CRE uses capacities and distances as the main cost drivers. The subscribed capacities are taken into account to determine the relevant flow scenarios used and to calculate the different distances (see point c).

1) The revenue collected at the points of entry and those collected at the points of exit are distributed according to the ratio retained by CRE: 34% at entry points and 66% at exit points. This historical ratio is explained by the presence of large storage capacities in France which lead to capacities reserved for entry points that are significantly lower than capacities reserved for exit points (see 4.2.2.2.1).
2) CRE determines the relevant flow scenarios to calculate distances:
   i. the relevant flow scenarios associate each exit point with one or more entry points (see point c and Appendix 9);
   ii. CRE then determines the shortest pipeline distance between the entry and exit points for each relevant flow scenario.
3) CRE classifies entry points into three homogeneous groups of points (IP, PITTM, PITS), whose tariff terms are harmonised. Therefore, entry rates are determined taking into account:
   i. provisional subscribed capacities at the various entry points;
   ii. distances arising from flow scenarios, weighted by the subscribed capacity;
   iii. a 60% discount applied to the entry tariff terms at the PITS, in order to take into account the role of storage facilities in terms of security of supply (see point d).
4) CRE classifies the PITS exit points and network exit points from the main network to domestic consumers into two homogeneous groups of points, whose tariff terms are harmonised. This equalisation

[35] Deliberation of the Energy Regulatory Commission of 7 October 2022 on the decision on the terms for commercialisation of natural gas storage capacities, applicable from October 2022

has no impact on the distribution of costs between cross-border exits and domestic consumers. Therefore, exit rates are determined taking into account:

i. provisional subscribed capacities at the various exit points;

ii. distances arising from flow scenarios, weighted by the subscribed capacity;

iii. a 60% discount applied to the exit tariff terms at the PITS, in order to take into account the role of storage facilities in terms of security of supply (see point d).

iv. In order to avoid cross-subsidisation between different categories of network users, CRE calculates the exit tariff terms such that the unit costs (€/MWh/d/year/km) for transporting gas to cross-border exits and to domestic consumers are identical.

b) Subscribed capacities retained

The subscribed capacities used by CRE to set the tariff terms of ATRT8 are presented in the table below. As indicated in section 3.2, the level of capacity selected has evolved since the public consultation.

MWh/d/year (average over the ATRT8 period)	Entry capacities subscribed	Exit capacities subscribed
IP Virtualys	188,500	19,000
IP Taisnières B	[confidential]	0
IP Dunkirk	550 000	0
IP Obergailbach	218,200	30,000
IP Oltingue	0	200,000
IP Pirineos	252,800	54,000
PITTM Dunkirk	370,000	
PITTM Fos	407,300	
PITTM Montoir	382,000	
PITTM Le Havre	110 000	
PITS Northwest	378,900	213,300
PITS Atlantique	637,500	312,500
PITS Southeast	644,800	109,800
PITS North B	77,900	42,200
PITS Northeast	176,000	125,000
PITS Southwest	556,400	300,800
Output to regional network		*3,870 000*

c) Determination of the relevant flow scenarios to calculate distances

CRE considers that the principles of the methodology for calculating reference prices in effect during ATRT7 remain relevant. However, since 2022, Europe and, a *fortiori,* France, have experienced a significant change in gas flow patterns, due to the decline in Russian gas supplies. Gas flows were previously mainly directed from the north and east of France to the south and west. These are now mostly from the south and west of France, with an increase in gas supplies from Spain (via Pirineos) and LNG terminals.

CRE considers that these significant changes imply changing the flow scenarios compared to those adopted for ATRT7. Taking into account the opinions of market participants expressed during the workshop of 4 May 2023, CRE considered, in its public consultation, retaining the following predictable supply and consumption patterns to define the flow scenarios:

- taking into account all entry points (IP, PITTM, PITS) as potentially relevant entry points to supply national consumers because the use of all these entry points is necessary in case of a cold spike. On the other hand, PITS are not considered as potentially relevant entry points for exporting gas to foreign countries from storage, consistent with the fact that the costs of storage compensation are paid only by domestic consumers;
- taking into account the Dunkirk IP as a potentially relevant entry point to supply the Obergailbach, Oltingue and Pirineos IPs. These three exit points are all likely to be fed with gas from Norway;
- taking into account the Virtualys IP as a potentially relevant entry point to supply the Oltingue and Pirineos IPs in order to reflect the LNG supply from Belgium (or from the Netherlands via Belgium);

- taking into account LNG terminals (PITTM) as potentially relevant entry points for export: given the decline in Russian gas supplies since 2022, LNG arriving in France is no longer only used to supply French consumers, but also exports, including to countries with their own LNG supply capacities, such as Spain and Italy;
- exclusion of the Obergailbach IP as a potentially relevant entry point for export to Switzerland and Italy via the Oltingue exit point. In fact, shorter and cheaper trips via other roads such as Germany-Switzerland-Italy exist and make such a flow scenario particularly unlikely;
- exclusion of the Virtualys IP as a potentially relevant entry point to export to Germany. As Belgium and Germany are directly interconnected, a shorter and cheaper route exists and makes such a flow scenario particularly unlikely.

Consequently, in its public consultation, CRE planned to establish the relevant flow scenarios on which its methodology for calculating reference prices is based as follows:

1. CRE planned to keep two flow scenario schemas, a "summer" schema (7 months) and a "winter" schema (5 months) in order to correctly reflect operation of the gas system according to the season:

- in the "summer" schema, the entry points are the IPs and the PITTMs. They are used to supply cross-border exit points, PITS exits to fill underground gas storage, and delivery points to domestic consumers in proportion to their annual baseline consumption;

in the "winter" schema, the entry points are the IPs, the PITTMs and the PITS. They are used to supply cross-border exit points and delivery points to domestic consumers at the level of their subscription at the exit from the main network. CRE assumes that PITS only feed delivery points to domestic consumers.

2. In each of the schemes (the "summer" scheme and the "winter" scheme), CRE considered that each exit point was supplied by the nearest entry point as long as there remained available subscribed capacity and in compliance with predictable supply and consumption schemas. This assumption is consistent with the configuration of the French network where the entry points of the main network are distributed on French territory and the national consumption is mainly located near borders. More specifically, within the limits of the subscribed capacities, CRE associates entries with each exit, making it possible to minimise, at the scale of the French system, the average distance between inputs and associated outputs, weighted by the subscribed capacities[36].

Responses to the public consultation

The majority of contributors to the public consultation are in favour of the flow scenarios thus foreseen by CRE and consider that they reflect the reconfiguration of flows since 2022 (more LNG, less Russian gas).

A few stakeholders make remarks.

One stakeholder considers that certain flow constraints of ATRT7 should be retained because it seems illogical to it that LNG can be unloaded in France to be exported to Italy or Spain, which have their own terminals.

Another respondent considers that users exporting gas from France benefit from storage and that the flow scenarios and the recovery base of the storage compensation should take this into account.

Two respondents believe that CRE should comment on the results of the calculation of flow scenarios so that market participants can understand why two inputs are sometimes necessary to feed an output and why it is not always possible to use the nearest input.

Finally, two respondents questioned the approach foreseen by CRE, which they consider different for national delivery points and for cross-border exits. They believe that the use of flow scenarios is similar to a point-to-point tariff, which they believe is incompatible with an entry-exit system. They would like CRE to apply the CWD reference price calculation methodology defined in article 8 of the tariff network code without flow scenario. These respondents also consider that Obergailbach (entry from Germany) should be considered as a possible feed source for the Oltingue (Switzerland / Italy) exit. According to them, the presence of a liquid market place in France makes it impossible to exclude one flow scenario or another.

CRE's analysis

CRE recalls that the possibility of combining points based on flow scenarios is provided for[37] in articles 3 and 8 of the tariff network code, as part of the standard reference price methodology (CWD):

[36] This calculation done using a linear optimisation algorithm called "Simplex" adapted to this type of problem (the average distance to be minimised and the capacity constraints to be respected are all expressed as linear functions).
[37] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on the harmonisation of tariff structures for the transport of gas

- article 3 (20) of the Tariff network code provides that: “a flow scenario is a combination of an entry point and an exit point representative of use of the transmission network based on predictable supply and consumption patterns and for which there is at least one pipeline for injecting gas into the transmission network at that entry point and withdrawing gas at that exit point, regardless of whether capacity is purchased at that entry point and exit point”.
- article 8 (1) of the Tariff network code provides that: "the parameters of the reference price calculation method based on capacity and distance as weighting factors are as follows: […] c) when the entry and exit points can be combined in a relevant flow scenario, the shortest distance by traversing the pipelines between an entry point or group of entry points and an exit point or group of exit points d) the combinations of entry points and exit points, when certain entry points and certain exit points can be combined in a relevant flow scenario”.

1. Compliance with an entry-exit system

In an entry-exit system, network users must be able to purchase entry and exit capabilities separately. They can thus transport gas from any point of entry to any point of exit, the TSO being responsible for managing the flows on its network. The tariff term at a given entry and exit point of the network must be independent of the destination and origin of the gas.

In this respect, use of relevant flow scenarios does not in any way call into question the tariff principle based on an input-output system. In fact, not only will network users always be able to separately reserve their entry and exit capacities from the network and, thus, have gas transported from any entry point to any exit point, but the level of tariff terms that users pay respectively at a given entry and exit point of the French network remains independent of the destination and origin of the gas.

Relevant flow scenarios are only taken into account by CRE to set the level of these terms. This level is set to reflect the costs incurred by TSOs for network use and associated investments, which depend mainly on two factors: capacity and distance.

CRE considers, like the Tariff network code, that there is no incompatibility between the flow scenarios and the input-output model. CRE stresses that this concept of input-output system must not be opposed to the objective of cost reflection. Thus, the entry and exit tariffs can reflect the costs of using the network, i.e. the costs associated with the combinations representing use of the entry and exit transport network based on the reservations of capacity of all users.

2. Exclusion of Virtualys and Obergailbach entries to feed Obergailbach and Oltingue exits respectively

Regarding exclusion of the Virtualys (from Belgium) and Obergailbach (from Germany) entries to feed, respectively, the Obergailbach (to Germany) and Oltingue (to Switzerland and Italy) exits, CRE considers that market players are rational and seek to maximise their profits. In both cases, there are direct interconnections from Belgium to Germany and from Germany to Switzerland. These direct routes are more competitive[38].

As a result, it is very unlikely that a gas exchange between a seller located in Belgium or Germany and a buyer located in Germany or Switzerland, respectively, will generate a capacity reservation or gas flow in France. If this were the case, the conditions of the exchange would be unnecessarily unfavourable (to finance the detour by France, the seller would have to agree to sell its gas at a lower price or the buyer would have to agree to buy it at a higher price). CRE does not consider that the presence of a liquid market place in France implies that gas flows will come from undifferentiated places. On the contrary, the creation of these liquid marketplaces in Europe has allowed shippers to optimise their flows based on economic signals and the most competitive marketplaces.

3. Role of LNG terminals

Regarding the consideration of LNG terminals as potential sources to supply the Oltingue and Pirineos outlets, CRE maintains that, due to the importance of LNG in the supply of Europe since 2022, it is relevant to consider that LNG arriving in France can be re-exported to neighbouring countries.

4. Role of storage

Finally, CRE considers that it is relevant that the flow scenarios adopted be consistent with the methods of collection of the storage compensation (*see* part 5): since national consumers are the main beneficiaries of storage in terms of security of supply, it is relevant that they bear the costs.

Result of calculation of flow scenarios

This calculation results in more than 600 flow scenarios for each "summer" and "winter" flow pattern.

[38] See ACER *Market Monitoring Report* , Figure 1 in Appendix 1 for entry and exit costs of different market areas

In the "summer" and "winter" schemas, the flow scenarios used make it possible to minimise the average distance between entries and exits, weighted by the subscribed capacities. This optimisation does not systematically lead to retaining the nearest inlet to supply each outlet. The subscribed capacities of the nearest entry point are sometimes fully used for other exits. It also happens that it is necessary to use two entry points to meet the needs of certain exit points whose subscribed capacities are significant.

CRE points out that, consistent with the actual functioning of the French system, the "summer" and "winter" schemas differ significantly due to the significant role of storage in the French system.

The flow scenarios presented above result in the average capacity-weighted distances below:

- a distance of 672 km for the IP Obergailbach exit point;
- a distance of 669 km for the IP Oltingue exit point;
- a distance of 835 km for the Pirineos IP exit point.

For domestic consumers, this results in approximately 600 defined relevant flow scenarios (one for each exit point to the regional network). The list of flow scenarios is given in Appendix 9 of the deliberation. The distances obtained vary from 1 km to 925 km.

With the exit tariff terms to the regional network being equalised, CRE retains the capacity-weighted average distance of these flow scenarios to supply domestic consumers, i.e. 249 km**.** It should be emphasised that this equalisation leads to a single distance (equal to 249 km) being retained for the supply of all points in the French territory, including those located near the exit points to the interconnections for which a different distance is retained as part of the flow scenarios. However, using a single average distance and, therefore, equalising the terms of exit to the regional network, has no impact on the overall distribution between the costs allocated to flows to cross-border outlets and those allocated to flows to domestic consumers.

Conclusion

In view of the above, CRE decides to apply its methodology for calculating the reference prices presented in its public consultation for ATRT8. CRE considers that this methodology complies with the provisions of the Tariff Network Code. These scenarios reflect use of the network via predictable supply and consumption patterns that CRE checks for consistency and reliability. The set of flow scenarios taken into account by CRE makes it possible to attribute the costs related to the constraints they generate to each category of network users.

In particular, CRE considers that the calculated flow scenarios make it possible to reflect the probable operation of the network, taking into account the capacities subscribed by all the actors and the geographical positions of the exit points (consumption areas, cross-border exits, storage in summer) in relation to the entry points (cross-border entries, LNG terminals, storage in winter). To illustrate, applying the CWD reference method of the Tariff network code without a flow scenario would amount to considering that national consumption is located more than 500 km from the entry points, i.e. entirely in the centre of the country, which does not correspond to reality.

d) Adjustment of tariff terms at storage entry and exit points

Article 9 of the Tariff Network Code provides that a discount of at least 50% shall be applied to capacity-based transport tariffs at points of entry to and exit from storage facilities. CRE set an 80% discount for the tariff terms of the PITS for ATRT7.

Compared to ATRT7, for ATRT8, CRE maintains the share of allowed revenue of the main network collected at the PITS (i.e. about 6%), which corresponds to a 60% discount applied to the tariff terms of the PITS. This level makes it possible to avoid adversely affecting the attractiveness of the storage facilities, to maintain an incentive for filling them and to take their role into account for proper functioning of the system and in terms of security of supply. The lost earnings resulting from this discount, respectively at entry and exit, are offset by realignment of the other tariff terms of entries and exits.

e) Coherence of unit costs

Article 5 of the Tariff Network Code provides that an assessment of the distribution of revenues associated with transport services is carried out in order to measure the degree of cross-subsidisation between use of the network internal to the system (domestic consumption) and use of the network to serve adjacent systems, based on the chosen method of calculating reference prices. This article also provides that any difference in distribution of these costs that exceeds 10% must be justified.

The result of the cost allocation comparison indices defined in this article and in application of the reference price calculation method decided by CRE, is 0%. In fact, the methodology for developing the tariff grid adopted by CRE makes it possible to obtain an identical unit cost for the supply of cross-border exits and the supply of national consumers.

Calculation of the comparison indices is summarised below. It takes into account the averages of the subscription assumptions during the ATRT8 period:

- Case of domestic consumption

The supply of 1 MWh/d/year of a national customer requires, on average, taking into account the subscriptions of storage capacities, the subscription of 0.57 MWh/d/year of entry capacities in France (IP/PITTM), and 0.64 MWh/d/year of entry capacity (extraction) at the PITS. These ratios are calculated on the basis of subscribed capacities (on average over the ATRT8 period). In addition, the subscription of 0.64 MWh/d/year of entry capacity at the PITS (extraction) requires the subscription of 0.29 MWh/d/year of exit capacity (injection) at the PITS (on average over the ATRT8 period).

$$Ratio_{cap}^{intra} = \frac{\text{Revenue}_{cap}^{intra}}{\text{Driver}_{cap}^{intra}} = \frac{(tarifs\ d'entrée + TCS) * capacité\ de\ sortie\ vers\ le\ réseau\ régional}{\text{Distance d'alimentation de la consommation nationale} * \text{Capacités}}$$

$$= \frac{(0{,}57 \times TCE_{\ PIR/PITTM} + 0{,}64 \times TCES_{\ PITS} + 0{,}29 \times TCSS_{\ PITS} + TCS_{\ vers\ RR}) * 3\,870\,000}{249 * 3\,870\,000} = 0{,}84$$

With:

- $Revenue_{cap}^{intra}$ is the revenue, defined in a monetary unit such as the euro, obtained from capacity tariffs billed for use of the network internal to a system;
- $\text{Driver}_{cap}^{intra}$; is the value of the cost factor(s) in relation to the capacity for use of the internal system network, such as the sum of the average forecast daily capacities subscribed at each point or group of internal system entry and exit points; it is defined in a unit of measurement such as MWh/day. The cost drivers considered by CRE are capacity and distance;
- TCE: tariff term of IP or PITTM entry;
- TCES: entry tariff term from the PITS (extraction);
- TCSS: exit tariff term to the PITS (injection);
- TCS: exit tariff term to the regional network (i.e. to national consumers).

- Case of cross-border flows:

The supply by a user of a cross-border exit up to 1 MWh/day/year requires the subscription of 1 MWh/day/year of entry capacities in France (IP/PITTM):

$$Ratio_{cap}^{cross} = \frac{\text{Revenue}_{cap}^{cross}}{\text{Driver}_{cap}^{cross}} = \frac{(\text{termes d'entrée} + \text{termes de sorties}) * \text{capacités de sortie transfrontalière}}{distances\ d'alimentation\ du\ transit * Capacités}$$

In the case of the Obergailbach exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Obergailbach}) * 30\,000}{30\,000 * 672} = 0{,}84$$

In the case of the Oltingue exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Oltingue}) * 200\,000}{200\,000 * 669} = 0{,}84$$

In the case of the Pirineos exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Pirineos}) * 54\,000}{54\,000 * 835} = 0{,}84$$

With:

- $\text{Revenue}_{cap}^{cross}$ is the revenue, defined in a monetary unit such as the euro, obtained from the capacity tariffs billed for use of the network for the service of adjacent systems;
- $\text{Driver}_{cap}^{cross}$ is the value of the cost factor(s) of the capacity for network use serving adjacent systems, such as the sum of the average forecast daily capacities subscribed at each point or group of entry

and exit points between systems; it is defined in a unit of measurement such as MWh/day. The cost drivers considered by CRE are capacity and distance;

- TCE: tariff term of IP or PITTM entry;
- TCST: tariff term of IP exit.

$$Comp_{cap} = \frac{2 * (Ratio_{cap}^{intra} - Ratio_{cap}^{cross})}{Ratio_{cap}^{intra} + Ratio_{cap}^{cross}} = \frac{2 * (0{,}84 - 0{,}84)}{0{,}84 + 0{,}84} = 0$$

The methodology for calculating the reference prices adopted by CRE results in an identical unit cost for the different categories of network users.

4.2.2.2.3 Special case of the exit to the Virtualys PIV

The interconnection at Alveringem was created in the framework of commissioning of the Dunkirk terminal in 2016, and makes it possible to physically transport non-odorous gas from France to Belgium. Two types of capacity are commercialised:

- capacity of direct entry into Belgium from the Dunkirk LNG terminal commercialised by Fluxys which, for this purpose, subscribes a routing service with GRTgaz between the Dunkirk terminal and Alveringem;
- capacity of interconnection between the TRF and the Belgian market commercialised in a coordinated manner by GRTgaz and Fluxys within the Virtualys Virtual Interconnection Point (PIV).

Given the short distance travelled in France by non-odorous gas to Belgium, a principle of tariff based on distance cannot be retained because it would not cover the costs of developing the interconnection created.

In its deliberation of 12 July 2011[39], CRE adopted a tariff based on exit capacity in Alveringem based on the actual cost of the investment observed at the end of the work and on the total level of capacity. In other words, the Virtualys PIV exit tariff term was calculated on the basis of an economic test so that the subscriptions at this point of the network cover a sufficient part of the related costs. This type of reasoning is in line with the spirit of the provisions adopted *a posteriori*, on 16 March 2017, in the Tariff network codes (Chapter IX) and CAM (Chapter V) concerning the development of additional capacities. The deliberation of 12 July 2011 provides that the tariff at the exit of the Virtualys PIV will evolve in accordance with the rest of the GRTgaz tariff.

The vast majority of respondents expressed support for the renewal of these principles in ATRT8.

Consequently, CRE decides to renew these principles for ATRT8.

4.2.2.2.4 Level of multipliers

Multipliers apply to the terms of the main network: they mainly aim to maintain a high level of long-term subscription, by encouraging stakeholders to subscribe annual capacities, rather than short-term capacities.

Article 13 of the Tariff Network Code provides that for quarterly and monthly capacity products, the multiplier level "*shall not be less than 1 or more than 1.5*". For daily and infraday capacity products, the multiplier level is not less than 1 or more than 3, except in duly justified cases.

The Tariff network code also specifies that several aspects should be taken into account when setting these multipliers, including:

- the balance between facilitating gas trade in the short term and providing long-term signals to permit effective investments in the transmission network;
- the impact on revenue associated with transport services and collection of it;
- situations of contractual or physical congestion.

The multipliers in effect in ATRT7, which vary between 1 and 1.5, are within the range specified by the Tariff network code. These multipliers have been set, on one hand, to maintain a high level of long-term subscriptions and, on the other hand, to facilitate short-term exchanges and promote market integration and liquidity.

In addition, when a point was congested (i.e. when allocating firm annual firm products at auction, the selling price of the capacities is strictly higher than the reserve price and at least 98% of the capacities commercialised

[39] Deliberation of the Energy Regulatory Commission deciding on the conditions for connecting the Dunkirk LNG terminal to the GRTgaz network and on the development of a new interconnection with Belgium in Veurne

have been subscribed), ATRT7 provided that a multiplier equal to 1 would apply for quarterly, monthly and daily products.

CRE considers that the levels set during ATRT7 have made it possible to meet the objectives of maintaining a high level of long-term subscription and, on the other hand, to facilitate short-term exchanges and promote market integration and liquidity.

In its public consultation, CRE foresaw maintaining the level of multipliers for ATRT8. In addition, CRE foresaw elimination of the congested tariff in ATRT8 in order to, on one hand, maximise the revenues collected at the interconnection points and, on the other hand, to maintain an incentive for users to reserve long-term capacities.

Finally, CRE foresaw, in the event that non-standard products were commercialised by TSOs during the ATRT8 tariff period, that the multiplier of the standard product of shorter duration would apply: for example, in the case of a seasonal product, the multiplier applicable to quarterly products would be applied.

All respondents to the public consultation share CRE's position on the level of multipliers.

Therefore, CRE decided to retain the ATRT7 multiplier level for ATRT8.

A large majority of respondents are also in favour of removing congested tariffs, and consider that this will promote long-term reservations.

CRE decides to remove congested tariffs.

Based on the responses to the public consultation, CRE decides that the following multipliers will apply for ATRT8:

Capacity	Coefficient	Multiplying factor
Quarterly	1/ 3 of annual term	1.33
Monthly	1/ 8 of annual term	1.5
Daily	1/30 of monthly term	1.5

In the event that non-standard products are commercialised by TSOs during the ATRT8 tariff period, CRE decides that the multiplier of the standard product of shorter duration applies: for example, in the case of a seasonal product, the multiplier applicable to quarterly products would be applied.

4.2.2.2.5 Pricing Table

The tariff grid applicable in 2024 is presented below in summary form. It is calculated on the basis of the operators' allowed revenue presented in section 3.3:

€/MWh/d/year	Current Terms	Terms at 1 April 2024	Terms at 1 October 2024	Change
IP Entries	105.70	105.70	130.63	+23.6%
IP entry Taisnières B	81.99	81.99	101.61	+23.9%
PITTM Entries	95.13	116.36	116.36	+22.3%
PITS Entries	9.22	10.88	10.88	+18.1%
Obergailbach IP exit	375.60	375.60	443.25	+18.0%
Oltingue IP Exit	386.85	386.85	440.47	+13.9%
Pirineos IP Exit	587.20	587.20	580.15	-1.2%
Virtualys IP Exit	42.05	42.05	52.17	+24.0%
PITS exits:	21.53	28.52	28.52	+32.5%
Exits from the main network to the regional network	95.20	124.42	124.42	+30.7%

Subsequently, the tariff terms will change annually, on 1 October for IPs and on 1 April for other tariff terms, by applying a coefficient Z=CPI + k, as described in 2.3.4 of the present deliberation.

4.2.3 Tariffs of interruptible capacities

In its public consultation of 26 July 2023, CRE planned to retain:

- an interruption rate and, therefore, a 50% discount for entry points at IP Dunkirk, Virtualys, Taisnières B and Obergailbach;
- a 25% discount to the Pirineos IP in line with the interruption probabilities calculated by the TSOs at the point of entry to Pirineos;
- 15% discount at Pirineos and Oltingue exit points;
- a 50% discount for interruptible capacities at PITS.

Respondents to the public consultation are in favour of these inclinations.

CRE considers that it is relevant to reconcile the applicable discounts to the actual interruption rates observed and maintains its guidelines expressed in the public consultation. Discounts applicable to interruptible capacities for the ATRT8 period are as follows:

Mainline Entry/Exit Points	Discount
Entries to IP Dunkirk, Virtualys, Taisnière B and Obergailbach	50%
IP Pirineos Entries	25%
Exits to IP Oltingue and Pirinéos	15%
Exits to PITS	50%

Feedback will be provided by the TSOs to determine the impact of changes in flow on the probability of interruption.

4.2.4 Tariffs of backhaul capacities

4.2.4.1 IP backhaul capacities

"Virtual Reverse Flow" capacities are capacities whose availability depends on the level of trade flow in the main direction of the interconnection point concerned. The commercial flows of gas from certain interconnection points into France, notably with Germany (Obergailbach) and Belgium (Virtualys), fell sharply or were interrupted, as gas prices on the German and Belgian markets exceeded the price on the French market.

The value of the backhaul capacities undergoes two contradictory effects. On one hand, decreases or interruptions in the physical flow reduce the availability (and therefore the value) of virtual backhaul capacities accordingly. On the other hand, the evolution of the gas price gap between the German or Belgian market and the French market has rather contributed to strengthening the value of these capacities.

For backhaul capacities, CRE foresaw maintain the 80% discount in its public consultation, compared to the tariff of the entry point to the IPs.

All respondents are in favour of the inclinations foreseen by CRE.

Given the feedback to the public consultation, CRE decided to maintain the 80% discount compared to the price of the point of entry to the IPs.

4.2.4.2 PITTM backhaul capacities

4.2.4.2.1 Principle of the offer of virtual liquefaction of LNG terminals

Elengy proposes to create a virtual liquefaction service. The principle of this offer is to allow all shippers active on the transport network to acquire LNG in tanks by making a "backhaul" appointment from the transport network to the terminal, which reduces the emission from the terminal to the network by as much. This "backhaul" designation would be done on the occasion of the intra-day allocation counter (and only when the terminal has the necessary flexibility). Dunkirk LNG plans to offer a comparable service.

CRE questioned the market twice about this offer:

- in its public consultation of 10 November 2022[40], CRE presented the principles of the offer, and the actors were in favour of an in-depth study of this service by CRE.
- in its public consultation of 26 July 2023, CRE presented the backhaul offer foreseen by GRTgaz, and considered two methods for setting the virtual backhaul tariff at the PITTM on the transmission network.

Only infrastructure operators expressed support for the creation of a virtual backhaul service to LNG terminals. The others (mainly suppliers) are opposed to it and have requested, at minimum, additional studies. In fact, these stakeholders consider it unfair that competitors not unloading LNG in France can acquire LNG without bearing the risks and costs of the LNG chain.

Given the feedback to the public consultation, CRE does not implement this measure during the period of ATRT8.

4.3 Tariff structure of regional network

The tariff of routing on the regional network depends on:

- the subscribed delivery capacity;
- the unit rate for routing on the regional network multiplied by a regional tariff level (NTR), specific to each delivery point, which makes it possible to take into account the disparity in routing costs on the regional network for each delivery point, notably depending on the distance to the main network.

The tariff of delivery depends:

- the subscribed delivery capacity;
- the unit delivery rate (TCL), which differs depending on the type of delivery point;
- the number of delivery stations for industrial consumers or highly modulated industrial consumers.

4.3.1 Conditions for subscribing capacities

4.3.1.1 Tariffs of infra-annual capacities

At the exit of the main network and for routing on the regional network and delivery, consumers connected to the transmission network can subscribe capacity for an annual, monthly or daily period. These subscriptions grant entitlement to an hourly delivery capacity equal to 1/20th of the daily delivery capacity subscribed. They can also request additional hourly capacity by paying an additional price.

[40] Public consultation no. 2022-13 of 10 November 2022 on the evolution on 1 April 2023 of tariffs for the use of gas transmission networks (ATRT7), storage facilities (ATS2) and regulated LNG terminals (ATTM6)

The gas transmission network is sized in order to be able to convey the quantity of gas necessary to pass from the peak consumption at risk 2% (called "P2" risk), i.e. the peak consumption at an extremely low temperature reached three days in a row, as occurs statistically once every 50 years.

This dimensioning implies that the network costs for a consumer present only in the coldest months is close to the costs generated by a consumer present all year round. Therefore, CRE has adopted tariff principles encouraging shippers to subscribe mainly on an annual basis. It is possible to reserve intra-annual capacities by paying the cost of the annual capacity multiplied by a certain coefficient, depending on the duration of the product and the time of year (with a higher coefficient in winter than in summer).

In addition, article D452-1-2 of the Energy Code provides that "tariffs for use of the transmission networks applicable during the months of November to April may be set at a level higher than that allowing strict coverage of the network costs, provided that they are subject, during the months of May to October, to a downward modulation allowing the cost coverage to be maintained over the year [...]".

Intra-annual capacity subscriptions are limited because the vast majority of consumers have their peak consumption in winter: they represent less than 4% of the capacity subscribed by consumers connected to the transport network.

CRE considered in the public consultation that the coefficients specified for ATRT7 were still relevant. It therefore foresaw renewing them for ATRT8 in its public consultation.
All respondents share CRE's position.

Given the feedback to the public consultation, CRE decided to maintain the following coefficients in ATRT8:

Capacity	Special conditions	Coefficient
Monthly	January - February - December	4/12 of annual term
	March - November	2/12 of annual term
	April – May – June – September – October	1/12 of annual term
	July – August	0.5/12 of annual term
Daily	Not applicable	1/30 of monthly term

4.3.1.2 Calculation of overrun penalties

In the ATRT7 tariff, daily and hourly capacity overruns were penalised as follows:

- for daily capacity overruns, the calculation of penalties is based on the price of the firm daily subscription of daily capacity:
    - for the part of the overrun less than or equal to 3% of the subscribed daily capacity, no penalty is charged;
    - for the part of the overrun greater than 3%, the penalty is equal to 20 times the price of the firm daily subscription of daily capacity;
- for hourly capacity overruns, the overrun is calculated by considering the maximum value of the hourly average of the quantities delivered to the delivery point concerned over four consecutive hours. The calculation of penalties is based on the price of the daily subscription of hourly capacity:
    - for the part of the overrun less than or equal to 10% of the hourly capacity subscribed, no penalty is charged;
    - for the part of the overrun greater than 10%, the penalty is equal to 45 times the price of the firm daily subscription of hourly capacity.

The penalisation rules applicable in the ATRT7 tariff can be summarised as follows:

	Daily capacity (J)	Hourly capacity (h)
Penalisation Floor	3%	10%
Penalisation	> 3% Penalty = daily price of daily capacity x 20	> 10% Penalty = daily price of hourly capacity x 45

The majority of contributors to the public consultation are in favour of renewal, for ATRT8, of the penalisation rules provided for by ATRT7. Some stakeholders, including consumer associations, consider them excessive.

CRE decides to renew the parameters of calculation of the overrun penalties for the ATRT8. The ATRT7 tariff had already lowered the penalty amounts and CRE considers that the penalties must be significant enough to dissuade industrial consumers from only reserving minimum capacities.

4.3.2 Biomethane Injection Fee[41]

Law no. 2018-938 of 30 October 2018 for the balancing of commercial relations in the agricultural and food sector and for healthy, sustainable and accessible food for all, known as the "EGalim Law", established the principle of the right to injection for biogas producers. In fact, its article 94 introduced article L. 453-9 into the Energy Code which provides, in particular, that "*[w]hen a biogas production facility is located close to a natural gas network, the operators of the natural gas networks carry out the necessary reinforcements to allow the injection of the biogas produced into the network, under conditions and limits making it possible to ensure the technical and economic relevance of the investments [...]*".

The procedures for implementing this article were specified by Decree no. 2019-665 of 28 June 2019 on reinforcement of the natural gas transmission and distribution networks necessary to allow injection of the biogas produced, and by the decree of 28 June 2019[42] adopted pursuant to 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 measures aimed, in particular, at efficient development of the injection of biomethane into natural gas networks.

- a zoning mechanism for connecting biogas production facilities to a natural gas network. For each zone of the continental metropolitan territory located near a natural gas network, it is a question of defining the most relevant network from a technical and economic standpoint for connection of a new biogas production facility located there. This zoning must be validated by CRE;
- for reinforcement structures, a mechanism for evaluation and financing by the network operators of the associated costs, within the limit of an Investments / Volumes ("I/V") technical-economic ratio;
- for shared structures that are not reinforcements, a cost-sharing mechanism between producers in the same zone.

CRE specified, in its deliberation no. 2019-242 of 14 November 2019[43] (hereafter, the "Biomethane Deliberation"), the operational procedures for implementing the right to injection and, in particular, those concerning the validation of investments to strengthen DSOs, for which the process was specified in deliberation no. 2020-261 of 22 October 2020[44].

In addition, the provisions of articles L. 452-1 and L. 452-1-1 of the Energy Code specify that the costs incurred by TSOs and DSOs[45] include part of the costs of connection to these networks of renewable gas production facilities, including biogas or low-carbon gas, and that the level of coverage may not exceed 60% of the cost of the connection.

All the aforementioned provisions thus lead to the pooling, in the ATRD and ATRT tariffs, of reinforcement costs in the technically and economically relevant areas, as well as the majority of connection costs: this pooling does not necessarily encourage producers to make optimal location choices for the community.

In order to preserve a signal at the optimal location and to cover the operating costs of the reinforcement work, CRE has introduced an injection fee into the ATRT7 and ATRD6 tariffs: based on the general principle of a three-level fee, it is allocated to each production site when the network managers submit the connection study

[41] Or of renewable and low-carbon gas, as will be defined in the ATRD7 deliberation of GRDF
[42] Order of 28 June 2019 defining the procedures for application of Section 6 of Chapter III of Part V of Book IV of the Energy Code
[43] Deliberation of the Energy Regulation Commission no. 2019-242 of 14 November 2019 on the decision on the mechanisms governing the insertion of biomethane into gas networks
[44] Deliberation of the Energy Regulation Commission no. 2020-261 of 22 October 2020 on the decision on the mechanisms governing the insertion of biomethane into gas networks and validation of GRDF's distribution investments associated with the development of biomethane
[45] For networks that are not licensed pursuant to article L. 432-6 of the Energy Code.

(corresponding to milestone D2[46] in the queue procedure), according to the connection zoning[47] in effect in the zone, and unchanged over the medium term. CRE may nevertheless decide, for production sites that have been assigned a level 3, to review their situation after five years, if the backhaul[48] (or mutualized compression) is not actually carried out by this deadline.

Classification of the zones by level is done according to the connection zoning in effect in the zone and is updated concomitantly with updating of the zoning:

- if the zoning provides for a backhaul or a pooled compression, the future production sites of the zone are assigned level 3;
- if the zoning does not provide for backhauls or pooled compression:
    - if the zoning includes a network[49] and/or a shared extension[50], the production sites of the zone are assigned level 2;
    - for the other zones, the production sites in the zone are assigned level 1.

To set the level of stamps in the ATRT7 and ATRD6 tariffs, CRE studied the operating expenses associated with the development of biomethane, with the exception of the general OPEX costs, in particular related to the management of biomethane activities and the operation of the IS: two categories of expenses were evaluated over the period, (1) the "backhaul OPEX" relating to backhauls and pooled compressions, and (2) the "pipelines OPEX" relating to networks and other pipelines.

On the occasion of the public consultations of 26 July 2023 and 12 October 2023, CRE foresaw several developments concerning the injection fee. The form, the level of the injection fee, its annual evolution as well as the share of revenue collected under the injection fee that will be paid between GRDF and the TSOs concerned will be specified in GRDF's ATRD7 deliberation.

Until ATRD7 takes effect, the terms of the injection fee provided for in ATRT7 will continue to apply.

4.3.3 Regional Network Tariff Grid for 2024

The applicable tariff grid for the GRTgaz and Teréga regional networks in 2024 is presented below in summary form. It is calculated on the basis of the operators' allowed revenue presented in section 3.3:

[46] Sites in the queue that have already passed milestone D2, but are not yet injecting biomethane, are assigned a fee level at the time of signing the connection contract, according to identical principles.
[47] Result of the study, conducted in consultation by the network managers, determining the optimal network configuration on the basis of the technical-economic zoning criterion.
[48] Compression facility permitting a natural gas flow from a pre-existing section of a natural gas transmission or distribution network to a pre-existing section of a higher pressure natural gas transmission or distribution network;
[49] Piping to connect two pre-existing sections of one or more natural gas distribution networks, including, if appropriate, a metering station at the network interface.
[50] Extension of a gas network to connect new sites, shared between several sites.

€/MWh/d/year		Current Terms	Terms at 1 April 2024	Change
GRTgaz	Terms of transmission capacity on the regional network (TCR)	84.29	96.38	+14.3%
	Delivery Capacity Terms (TCL)			
	Final consumer connected to the transmission network	33.54	38.35	+14.3%
	RIP	43.06	49.24	+14.3%
	PITD	49.52	56.62	+14.3%
	Fixed term per delivery station	6,472.55	7,400.61	+14.3%
Teréga	Terms of transmission capacity on the regional network (TCR)	84.79	102.60	+21.0%
	Delivery Capacity Terms (TCL)			
	Final consumer connected to the transmission network	30.73	37.18	+21.0%
	PITD	55.52	67.18	+21.0%
	Fixed term per delivery station	3,398.63	4,112.46	+21.0%

This tariff grid shows a significant increase in tariff terms compared to ATRT7. It is the result of several effects:

- the expected decrease in subscriptions during the ATRT8 period presented in section 3.2;
- the increase in operators' expenses compared to ATRT7 presented in part 3.

As indicated in section 2.3.4, CRE decides to apply a $Z_{regional}$ variation to the tariff terms of the regional networks each year with $Z_{regional}$ = IPC + $k_{regional}$.

The tariff grid presented above corresponds to the following inflation assumptions:

	2025	2026	2 027
Inflation (CPI)	2.00%	2.00%	1.80%

5. Storage compensation collection methods

Since 2018, storage infrastructure operators have been subject to economic regulation. It provides that:

- storage capacities that guarantee security of supply are provided for by the PPE. These infrastructures are maintained in operation by storage operators;
- the revenue of storage operators is determined by CRE;
- storage capacities are commercialised by auction according to the terms defined by CRE;
- the difference, positive or negative, between the revenues mainly from auctions and the regulated revenue of storage operators is offset by a tariff term determined by CRE within the tariff for use of the natural gas transmission network.

Implementation of the regulation thus aims to guarantee the subscription and then filling of the storage capacities necessary for the security of supply, while providing transparency on the costs. The regulation of operator revenues also aims to ensure that the final consumer pays the right price for the storage necessary for security of supply.

These objectives have largely been achieved. Since the effective date of the regulation, almost all the proposed capacities have been allocated thanks to the auction mechanism making it possible to commercialise the storage facilities at their market value. At the same time, the mechanism of compensation between storage and transport made it possible to effectively cover the costs of operators that were not reflected by the market value. While serious crises (Covid, war in Ukraine) have followed one another and market conditions have been volatile since the effective date of the regulation of storage facilities, this good functioning has made it possible to guarantee France's security of natural gas supply at a controlled cost.

The auctions generated an average of ~300 M€/year in revenue, which represents 45% of the operators' allowed revenue.

CRE considers that the terms of the storage compensation are appropriate and that they have proven their resilience in the face of the various shocks suffered by the European gas system since 2018. It therefore decides to renew the provisions of ATRT7 for the ATRT8 tariff period.

5.1 Principle of cost recovery

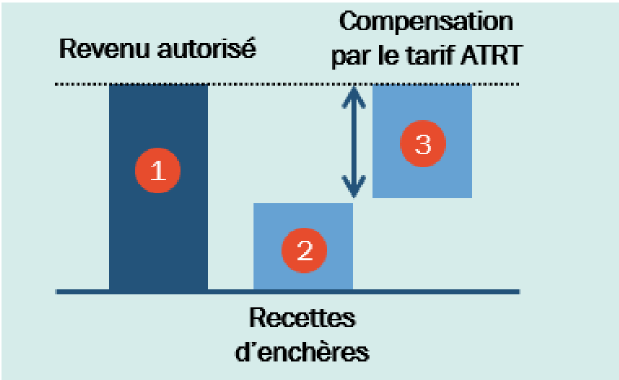
Article L. 421-3-1 of the Energy Code provides that "[t]he underground natural gas storage infrastructures that guarantee security of supply [...] are provided for by the multi-annual energy programming [...]. These infrastructures are maintained in operation by the operators [...] ". In return and within the limits of the obligation to maintain the operation of storage sites considered necessary for security of supply in the multi-annual energy programming, storage operators are guaranteed to have their expenses covered, insofar as these expenses are those of an efficient operator.

The Energy Code provides that storage operators receive their allowed revenue, set by CRE:

- on one hand, through the revenues they receive directly, mainly from commercialisation of their auction storage capacities;
- on the other hand, in the event that the revenues they receive directly are less than their allowed revenue, through compensation collected by the TSOs from shippers and paid to storage operators in accordance with article L. 452-1 of the Energy Code[51].

In this context, CRE sets, before 1 April of each year, the amount of compensation, for each of the three storage operators, corresponding to the difference between the operators' allowed revenue for the year in question and the revenue forecasts related to commercialisation of storage capacities directly received by the operators.

The amount of this compensation is recovered from shippers present on the GRTgaz and Teréga transmission networks, by applying a storage tariff term to them based on the winter modulation of their customers connected to the gas transmission and public distribution networks.



5.2 Scope of storage compensation

CRE defined the initial scope of the collection base of the storage compensation in its deliberation of 22 March 2018[52]. As of 1 April 2018, the scope retained corresponded to all consumers connected to the distribution network that had not established a contract for a supply that could be interrupted, or that had not declared themselves subject to shedding.

This perimeter was retained by CRE given:

- on one hand, restricted deadlines for implementation of the reform of the regime for third-party access to underground natural gas storage facilities and in order to ensure the necessary continuity with the previous system;
- on the other hand, the absence of a contractual measure of interruptibility allowing consumers directly connected to the transmission network that may interrupt their consumption in certain exceptional situations, to be exempt from payment of the storage tariff term.

[51] In the event that the revenues are greater than the allowed revenue of the storage operators, the storage tariff term is negative and results in a repayment to the shippers.
[52] Deliberation of the CRE 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

Once the contractual interruptibility measure was effectively implemented, CRE extended the compensation base to customers directly connected to the transmission network. This extension took place on the occasion of updating of the ATRT7 tariff on 1 April 2021[53].

CRE decides to renew the collection scope of the storage compensation for ATRT8.

5.3 Calculation of the storage tariff term

CRE decides to renew the terms for calculating the storage tariff term.

The storage tariff term is calculated as the ratio between the estimated amount of the France network compensation and the estimated value of the basis for collecting this compensation.

$$TTS = \frac{\textit{revenu autorisé des opérateurs} - \textit{recettes de commercialisation}}{\textit{assiette de compensation}}$$

Amount of compensation:

The amount of compensation corresponds to the difference between the operators' allowed revenue for the year in question and the revenue forecasts related to the commercialisation of storage capacities directly received by the operators

Basis for compensation:

For any shipper to which firm delivery capacity to at least one PITD is allocated, or that supplies a customer directly connected to the transport network, a storage tariff term (TS) is applied based on the winter modulation of its customers in its portfolio on the 1st day of each month. This term is intended to recover a portion of revenues from underground natural gas storage operators.

The basis of collection of the compensation to be collected from each shipper is defined as the sum of the bases of each of its customers eligible for payment of the storage compensation (calculation of the modulation is specified in section 6.2.3.2).

6. Tariff for use of the natural gas transmission networks of GRTgaz and Teréga applicable on 1 April 2024

6.1 Tariff Rules

6.1.1 Definitions

Network Interconnection Point (IP): physical or notional point of interconnection of the main transmission systems of two transmission system operators (TSOs).

Regional Interconnection Point (RIP): physical or notional point of interconnection between a regional transport network and the network of a foreign operator.

LNG Transport Terminal Interface Point (PITTM): physical or notional point of interconnection between a transport network and one or more LNG terminals.

Transport Storage Interface Point (PITS): physical or notional interface point between a transport network and a storage group.

Transport Production Interface Point (PITP): physical or notional interface point between a transmission network and a gas production facility operated by a mining concession.

Transport Distribution Interface Point (PITD): physical or notional interface point between a transmission network and a public distribution network.

TCE: term of entry capacity on the main network, applicable to the subscription of daily capacity at the entry points of the main network from an IP or a PITTM;

TCES: term of entry capacity on the main network from storage, applicable to the subscription of daily entry capacity on the main network from a PITS;

[53] Deliberation no. 2021-15 from the CRE of 21 January 2021 deciding on the annual evolution of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga on 1 April 2021

TCST: term of exit capacity at transmission network interconnection points, applicable to the subscription of daily exit capacity to a network interconnection point (IP);

TCS: term of exit capacity from the main network, applicable to the subscription of daily exit capacity of the main network, except to a PITS or an IP;

TCSS: term of exit capacity from the main network to storage, applicable to the subscription of daily exit capacity from the main network to a PITS;

TCR: term of transmission capacity on the regional network, applicable to the subscription of daily transmission capacity on the regional network;

TCL: term of delivery capacity, applicable to the subscription of daily delivery capacity to a delivery point;

Storage Term (TS): Unit tariff term aimed at recovering part of the revenues of underground natural gas storage operators, applicable to shippers, depending on the winter modulation of their customers.

Biomethane injection term: term applicable to the quantities of biomethane injected into the gas transmission network;

Firm capacity: gas transmission capacity for which use is contractually guaranteed by the TSO, excluding work or cases of force majeure.

Firm climatic capacity: gas transmission capacity for which the TSO guarantees the uninterruptible nature by contract, depending on domestic consumption. This definition notably applies to the injection and extraction capacities at the PITS.

Reverse flow capacity: capacity allowing the shipper to make designations in the opposite direction of the dominant direction of flows when gas flows can only flow in one direction. It can only be used on a given day if the overall flow resulting from all shipper designations are in the dominant direction of flows.

Interruptible capacity: gas transmission capacity that can be interrupted by the TSO according to the conditions stipulated in the transmission contract for the gas transmission network.

Returnable capacity: firm capacity which the shipper agrees to return at any time to the TSO at its request.

Shipper: natural person or legal entity that establishes a transport contract with a TSO on the gas transmission network. The shipper is, as the case may be, the eligible customer, the supplier or their agent.

Delivery point (PDL): an exit point from a distribution network where a distribution system operator delivers gas to an end customer, in execution of a contract for transmission on the distribution network. Each PDL is generally attached to a metering and estimation point (PCE), with a unique 14-digit number to identify it. As an exception, a PDL may nevertheless group several PCEs, if they are downstream of the same individual connection.

Annual reference consumption (CAR): estimated amount of gas consumed over a year, under average climatic conditions, for a metering and estimation point (PCE).

"**Non-subscription" customer:** customer covered by the T1, T2 and T3 options of the tariffs for use of the distribution networks. As these options do not include any capacity subscription term, the PDLs of these customers are, therefore, "non-subscription". Each "non-subscription" PDL is associated with a so-called "normalised" capacity, determined from its CAR, its profile, the peak temperature [at] 2% of the weather stations to which the PITD concerned is attached, and an adjustment coefficient "A".

"**Subscription" customer:** customer covered by the TF, T4 and TP options of the tariffs for use of the distribution networks. For these PDLs, the supplier freely reserves the desired capacity.

Winter share (PH): the ratio between the customer's consumption from November through March and its consumption over the entire calendar year.

6.1.2 Subscriptions of capacity

6.1.2.1 Capacity subscriptions to IPs at auction

Daily routing capacities at the network interconnection points (IP) of Taisnières B, Virtualys (Taisnières H and Alveringem), Obergailbach, Oltingue and Pirineos can be subscribed at auctions via the capacity commercialisation platform PRISMA. These capacities are commercialised by auction in accordance with Commission Regulation (EU) 2017/459 of 16 March 2017 establishing a network code on capacity allocation mechanisms in gas transmission systems known as the "CAM Network Code". The details of the auction procedures and the products offered are published by GRTgaz and Teréga on their respective websites or on the PRISMA auction platform.

As an indication, firm, interruptible and backhaul daily delivery capacity products are available for annual, quarterly, monthly, daily and infraday periods.

The reserve price of the auctions is equal to the price set by this deliberation.

The contract establishment and invoicing for the IPs of Taisnières B, Virtualys (Taisnières H and Alveringem), Obergailbach and Oltingue are done by GRTgaz.

Contract establishment and invoicing for the Pirineos IP are done by Teréga.

6.1.2.2 Subscription of capacities at IP Dunkirk

Subscriptions of daily capacities at IP Dunkirk are subject to specific commercialisation mechanisms defined according to rules set by CRE and made public on the GRTgaz website.

6.1.2.3 Subscription of capacities at PITS

The TSO automatically allocates to the shipper at each Transport Storage Interface Point (PITS) exit and entry capacities corresponding to the nominal injection and extraction capacities that the shipper holds for the corresponding storage group(s), within the limits of the network capacities.

The level of firm exit capacities at PITS is set by CRE. The remaining allocated capacities are interruptible.

6.1.2.4 Subscription of capacities at PITTM

The holding of regasification capacities in an LNG terminal entails the right and obligation to subscribe the entry capacities on the transport network, for corresponding durations and levels. In the specific case of the Dunkirk LNG terminal (the terminal is connected to both the GRTgaz network and the Belgian network), this obligation relates to the sum of the capacities reserved on the GRTgaz network at the Dunkirk PITTM and the capacities reserved from the terminal to Belgium.

At the Dunkirk PITTM, firm entry capacities on the GRTgaz network are reserved by the shipper in the form of annual bands, over a period representing a whole number of years, or in the form of intra-annual bands.

At the Montoir, Fos and Le Havre PITTMs, any shipper that has subscribed capacities with LNG terminal managers is allocated a firm daily entry capacity by the TSO, for the subscription period of the corresponding regasification capacities:

- in the case of subscriptions for regasification capacity falling within the scope of the terminal's annual schedule (in particular, annual or multi-annual), the level of firm daily entry capacity allocated corresponds to a share of the terminal's firm daily regasification capacity. This share is determined by the ratio:
    - of the annual regasification capacity subscribed by the shipper at the terminal;
    - over the total annual firm regasification technical capacity of this terminal.

  The firm daily regasification capacity is equal to 113.5% of the average daily unloading capacity in the terminal.
- in the case of subscriptions for spot regasification capacity, the shipper is assigned a firm entry capacity band over the period of its subscription. The allocated capacity level corresponds to the amount of subscribed regasification capacity, expressed as GWh.

A shipper with capacity subscribed at a PITTM may change the level the day before for the next day, provided that it retains the full level of capacity initially subscribed over the period concerned (duration of the subscription or calendar year, if the subscription has a duration of more than one year).

The TSO calculates, for each shipper, the daily emissions for each day. For a given day, if they exceed the capacity held by the shipper, it charges the latter an additional subscription of daily capacity, at the daily capacity rate, equal to the positive difference between the daily emission and the capacity allocated by the shipper.

Shippers have the option of surrendering their capacities to the PITTM at no cost.

In addition, any capacity subscribed for a PITTM for month M and which the shipper ultimately does not intend to use may be transferred after the 20th of month M-1 to another PITTM for this month M. The cost of this transfer corresponds to 10% of the initial price of the new subscribed capacity.

6.1.2.5 Subscription of capacities for exit from the main network and on the regional network

The reservation of delivery capacities at delivery points and Regional Network Interconnection Points (RIPs), routing capacities on the regional network and exit capacities from the main network is done with the TSOs according to the procedures published by the TSOs.

Firm delivery capacities at Transport Distribution Interface Points (PITDs) are automatically allocated by the TSOs. These capacities are calculated by the TSOs on the basis of data provided by the public gas distribution system operator. The method of calculating standard delivery capacities is established on an objective and transparent basis, preventing any discrimination, and made public.

The shipper shall be allocated an exit capacity from the main network and a routing capacity on the regional network equal, for each delivery point and for each RIP, to the delivery capacity at that point.

6.1.2.6 Subscription of capacities at biomethane injection points

The shipper is allocated an injection capacity equal to the production capacity of the site as recorded in the capacity register, for the duration of the purchase contract it has established with the producer site.

6.1.3 Transfer of transmission capacity on the GRTgaz and Teréga networks

The transport capacities subscribed at the entry and exit points to the IPs are freely transferable at no additional cost.

In the event of a complete sale, the buyer shall recover all rights and obligations related to these subscriptions.

In the event of transfer of the right of use, the original owner retains its obligations vis-à-vis the TSO. The exchanged usage right can go down to a daily time step, regardless of the duration of the initial subscription.

The right to use downstream transport capacities, between the PEG and the delivery point at an industrial site directly connected to the transport network, or between a PITP and the PEG, is transferable in the event that the industrial company concerned has subscribed these capacities with the TSO.

The terms of these transfers of transmission capacity are defined by the TSOs, on an objective and transparent basis, and made public by the TSOs on their website.

6.2 Pricing grid for use of the GRTgaz and Teréga networks on 1 April 2024

6.2.1 Forecast revenue to be collected by the transport tariff

Tariffs and projected tariff changes are set, based on assumptions of the level of capacity subscriptions, so as to cover the allowed revenues of each of the TSOs.

- GRTgaz:

GRTgaz, in M€$_{current}$	2024	2025	2026	2 027
Forecast revenue to be collected by the tariff	1,976.6	2,067.4	2,016.0	1,923.7

- Teréga:

Teréga, in M€$_{current}$	2024	2025	2026	2 027
Forecast revenue to be collected by the tariff	264.8	271.2	260.4	223.8

6.2.2 Rates applicable to annual subscriptions of daily routing and delivery capacity

6.2.2.1 Tariff of Network Interconnection Points (IPs) before 1 October 2024

The rates applicable to annual subscriptions of daily capacity are defined in the tables below. For commercialisation at auctions, the auction reserve prices are equal to these rates.

Terms of entry capacity on the principal network (TCE)

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm Annual*	TCE (coefficient on firm term) *Annual interruptible*
Taisnières B	GRTgaz – North B	81.99	50%
Virtualys (Taisnières H)	GRTgaz	105.70	50%
Dunkirk (IP)	GRTgaz	105.70	50%
Obergailbach	GRTgaz	105.70	50%
Oltingue	GRTgaz	105.70	50%
Pirineos	Teréga	105.70	50%

IP Exit Capacity Terms (TCST)

Exit at	Balancing zone	TCST (€/MWh/day per year) *Firm Annual*	TCST (coefficient on firm term) *Annual interruptible*
Virtualys (Alveringem)	GRTgaz	42.05	Not applicable
Oltingue	GRTgaz	386.85	85%
Obergailbach	GRTgaz	375.60	Not applicable
Pirineos	Teréga	587.20	85%

IP Reverse Flow Capacity Terms

Exit at	Balancing zone	Entry coefficient on firm term *Annual for backhaul*
Taisnières B	GRTgaz	20%
Virtualys (Taisnières H)	GRTgaz	20%
Obergailbach	GRTgaz	20%

Entry at	Balancing zone	Exit coefficient on firm term *Annual for backhaul*
Virtualys (Alveringem)	GRTgaz	125%

Returnable Capacities

The price of a returnable annual capacity is equal to 90% of the price of the corresponding annual firm capacity.

6.2.2.2 Tariff of Network Interconnection Points (IPs) from 1 October 2024

The rates applicable to annual subscriptions of daily capacity are defined in the tables below. For commercialisation at auctions, the auction reserve prices are equal to these rates.

Terms of entry capacity on the principal network (TCE)

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm Annual*	TCE (coefficient on firm term) *Annual interruptible*
Taisnières B	GRTgaz – North B	101.61	50%
Virtualys (Taisnières H)	GRTgaz	130.63	50%

Dunkirk (IP)	GRTgaz	130.63	50%
Obergailbach	GRTgaz	130.63	50%
Oltingue	GRTgaz	130.63	50%
Pirineos	Teréga	130.63	75%

IP Exit Capacity Terms (TCST)

Exit at	Balancing zone	TCST (€/MWh/day per year) *Firm Annual*	TCST (coefficient on firm term) *Annual interruptible*
Virtualys (Alveringem)	GRTgaz	52.17	Not applicable
Oltingue	GRTgaz	440.47	85%
Obergailbach	GRTgaz	443.25	Not applicable
Pirineos	Teréga	580.15	85%

IP Backhaul Capacity Terms

Exit at	Balancing zone	Entry coefficient on firm term *Annual for backhaul*
Taisnières B	GRTgaz	20%
Virtualys (Taisnières H)	GRTgaz	20%
Obergailbach	GRTgaz	20%

Entry at	Balancing zone	Exit coefficient on firm term *Annual for backhaul*
Virtualys (Alveringem)	GRTgaz	125%

Returnable Capacities

The price of a returnable annual capacity is equal to 90% of the price of the corresponding annual firm capacity.

6.2.2.3 Tariffs of Methane Transport Terminal Interface Points (PITTM)

Terms of entry capacity on the principal network (TCE)

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm subscriptions*
Dunkirk LNG	GRTgaz	116.36
Montoir	GRTgaz	116.36
Fos	GRTgaz	116.36
Le Havre	GRTgaz	116.36

6.2.2.4 Tariffs of Transport Storage Interface Points (PITS)

Storage entry and exit capacity terms (TCEs and TCSS)

PITS	Balancing zone	Type of capacity	Entry - TCES (€/MWh/day per year) *Annual*	Exit - TCSS (€/MWh/day per year) *Annual*	Exit - TCSS (coefficient on firm term) *Annual inter-ruptible*
Northwest	GRTgaz	Climate firm	10.88	28.52	50%
Northeast	GRTgaz	Climate firm	10.88	28.52	50%
North B	GRTgaz – North B	Climate firm	10.88	28.52	50%
Atlantique	GRTgaz	Climate firm	10.88	28.52	50%
Southeast	GRTgaz	Climate firm	10.88	28.52	50%
Southwest	Teréga	Climate firm	10.88	28.52	50%

6.2.2.5 Tariff of exit capacity from the main network to delivery points

Terms of exit capacity from main network

Exit from	TCS (€/MWh/day per year) *Firm Annual*	TCS (coefficient on firm term) *Annual interruptible*
GRTgaz	124.42	50%
Teréga	124.42	50%

6.2.2.6 Tariff of routing on the regional network

Terms of transmission capacity on the regional network (TCR)

Regional Network	TCR (€/MWh/day per year) *Firm Annual*	TCR (coefficient on firm term) *Annual interruptible*
GRTgaz	96,38 x NTR	50%
Teréga	102,60 x NTR	50%

The term applicable to firm annual subscriptions for daily transmission capacity on the regional network (TCR) is the product of a fixed unit term and the regional tariff level (NTR) of the delivery point in question.

The list of delivery points on the GRTgaz and Teréga network, accompanied by their exit zone and their NTR value, appears in Appendix 6 of this deliberation.

When a new delivery point is created, GRTgaz or Teréga calculates the value of the NTR in a transparent and non-discriminatory manner, based on a calculation method published on their respective websites.

Delivery Capacity Terms (TCL)

Transport network	Type of delivery point	TCL (€/MWh/day per year) *Firm Annual*	TCL (coefficient on firm term) *Annual interruptible*
GRTgaz	**Final consumer connected to the transmission network**	38.35	50%
	RIP	49.24	Not applicable
	PITD	56.62	Not applicable
Teréga	**Final consumer connected to the transmission network**	37.18	50%
	PITD	67.18	Not applicable

If several shippers simultaneously supply a RIP, the term set is distributed in proportion to their delivery capacity subscriptions.

In application of the system of standard subscription of transmission capacity to the PITDs, for each PITD, the firm annual delivery capacity ("standard capacity") is allocated to each shipper by the TSOs. It is equal to the sum:

– of the annual capacities subscribed on the distribution network for the "subscription" delivery points (PDL) supplied downstream of the PITD in question;

– of the capacities calculated by the TSOs for the "non-subscription" PDLs supplied downstream of the PITD in question, by multiplying the peak daily consumption of the "non-subscription" PDLs by the corresponding adjustment coefficient "A".

An evolution of the A coefficients is possible on 1 April of each year via a deliberation of CRE on the proposal of the TSOs for their balancing zones and for each distribution system operator present in these zones.

Term set per delivery station

Shippers supplying final consumers connected to the transport network and RIPs pay a term set per delivery station:

Term set per station	€/station per year
GRTgaz	7,400.61
Teréga	4,112.46

6.2.3 Storage tariff term depending on winter modulation (TS)

6.2.3.1 Amount of compensation to be received

The amount of compensation to be received by an operator of underground natural gas storage infrastructures and which will be collected by the TSOs, corresponds to the difference between (i) the operator's allowed revenue for 2024, set by CRE in its deliberation of 30 January 2024 relating to the ATS3 tariff, and (ii) the revenue forecasts collected directly by the operator for the year 2024. This calculation is performed for each of the operators. It makes it possible to define the share of compensation paid by each TSO to each of the operators by considering the ratio between the operator's annual forecast compensation and the total annual forecast compensation.

The amounts that will be retained by CRE to calculate the 2024 compensation are as follows:

i. for allowed revenue, CRE will retain the amount set in its deliberation of 30 January 2024 relating to the ATS3 tariff;

ii. for the estimated revenue directly received by storage operators, CRE notably retains:

a) the revenue received by storage operators for storage capacities and additional services for 2023-2024, for the first 3 months of 2024;

b) the revenue received by operators for storage capacities and additional services for 2024-2025, for the last 9 months of 2024.

The amount of compensation is calculated annually. It will be set by CRE at the end of the auction campaign, at the beginning of March 2024.

6.2.3.2 Calculation of winter modulation

For any shipper to which firm delivery capacity to at least one PITD is allocated, or that supplies a customer directly connected to the transport network, a storage tariff term (TS) is applied based on the winter modulation of its customers in its portfolio on the 1st day of each month. This term is intended to recover a portion of revenues from underground natural gas storage operators.

The basis of collection of the compensation to be collected from each shipper is defined as the sum of the bases of each of its customers eligible for payment of the storage compensation.

The modulation is notably calculated on the basis of data provided by the public gas distribution system operators.

The winter modulation level is determined on the 1st day of the month, for each of the customers, by applying the calculations described below.

- **Subscription customers (connected to transmission and distribution networks)**

For subscription customers, the modulation as of 1 April is calculated as follows:

$$\textbf{Modulation client au 1er avril N } (\textbf{MWh/j}) = \text{Max}(0; M_{fav4} - \text{Int})$$

Where:

• M_{fav4} is the average of the 2 lowest annual modulations of the previous 4 years, i.e. years N-4 to N-1. For each of the years considered, the modulation calculation is as follows:

$$\textbf{Modulation annuelle N } (\textbf{MWh/j}) = \text{Max}(0\,;\ \frac{\text{Consommation hiver}}{151} - \frac{\text{Consommation annuelle}}{365})$$

Where: - Winter consumption: site consumption from 1 November N-1 to 31 March N

- Annual consumption: consumption from 1 November N-1 to 31 October N

• Int is the sum of interruptible capacities for which contracts with network operators have been established on 1 April of the current billing year. This sum includes the annual interruptible capacities for which the shipper has established a contract to meet technical supply constraints at the request of the TSO and those for which contracts have been established by the consumer in the framework of the contractual interruptibility measures defined by the decree of 17 December 2019.

For sites connected to the distribution networks, the level of interruptible capacities taken into account is equal to the difference between the average value of the sum of the annual, monthly and daily capacities subscribed each day between 1 November N-1 and 31 March N, and the contractual ceiling capacity for the period from 1 April N to 31 March N+1. If the value obtained by this difference is negative, the level of interruptible capacities subscribed is considered to be zero.

When a consumer loses its approval of the interruptibility contract, due to non-activation of the interruptible capacities called by the network operators or the failure of an activation test, the storage compensation amount is adjusted by zeroing out of the corresponding interruptible capacities, from the following billing month until a subscription of new interruptible capacities.

In the event that the interruptibility contract is signed for several delivery points, the consumer must specify the distribution of interruptible capacities between these delivery points to the TSO, for the sole purpose of calculating the storage compensation (without anticipating the operational impact on interruptibility).

In the case of a new site connected for transport, in the absence of a history of actual consumption, the modulation of the site will be determined by the TSOs on the basis of the best estimate of the winter modulation provided by the shipper supplying the site. The storage compensation will thus be invoiced from the month following the connection.

In the case of a new site connected as an optional "subscription" distribution, in the absence of a history of actual consumption, the modulation of the site will be determined by the DSOs on the basis of the best estimate of the annual reference consumption (CAR) and the consumption profile communicated to the DSO in the framework of connection by the site supplier. Thus, the invoicing of the storage compensation will begin from the first month following connection of the site on the basis of this estimate.

As long as, on 1 April of year N, a full year of calculation data is available (i.e. consumption data going back to 1 November of year N-2 is available), invoicing will be done on the basis of this first year of actual consumption data. On 1 April of the following year, the modulation will be calculated as the average of the two available modulation values and, finally, on the following 1 April, the chosen modulation will correspond to the average of the two lowest values among the three available.

In addition, in all cases other than that of a new site connected via the "subscription" option, it will be the responsibility of the network operators to ensure the continuity of billing of the storage compensation through use of the history of consumption data in their possession.

- **<u>"Profiled" customers (connected to distribution networks)</u>**

For "profiled" customers, the modulation of a year N is calculated as follows:

$$\text{Modulation client (MWh/j)} = Max(0; CJN - \frac{CAR}{365} - Int)$$

Where:

- the Annual Reference Consumption (CAR) is the estimate of the annual consumption of a Metering and Estimation Point (PCE) in an average climate year;
- the Normalised Daily Capacity (CJN) is such that:

$$\text{CJN} = A.zi.CAR$$

Where:

  - A is a coefficient reflecting the ratio between the capacities, called "normalised", calculated by the TSOs for the "non-subscription" PDLs, supplied downstream of a given PITD, for each DSO on each balancing zone and, over the same perimeters, the peak daily consumption of these PDLs calculated by the profiling algorithm of the DSOs;
  - Zi coefficient: conversion coefficient taking into account the weather station and the customer's consumption profile. The method of assigning profiles is available on the GTG website[54].
- INT: sum of interruptible capacities for which contracts will be established with network operators within the framework of the decisions relating to interruptibility measures.

The operators of public gas distribution networks send the TSOs the data necessary for calculation of the level of winter modulation, as defined above.

In some cases, especially for some DSOs that do not have information on the consumption profile of their historical customers, some data (CAR, profiles) may not be available. The TSOs may substitute the CAR with an equivalent depending on the estimate of the overall CAR of the PITD.

In the event that a DSO does not transmit, over time, the data necessary for calculation of the basis for the customers in its perimeter, the TSO will apply, for the customers in question, a method based on the subscribed capacity. This calculation will be corrected a posteriori, once the DSO sends the data.

- **<u>Other provisions</u>**

As an exception with these formulas, the customer Modulation is set at 0 MWh/d for counter-modulated customers, i.e. customers with a P013 profile (Winter Share less than or equal to 39%) or a P014 profile (Winter Share between 39% and 50%).

[54] Calculation of Zi coefficients

In the event of a change during the year from the T3 profiled tariff option to a subscription tariff option on the distribution network, invoicing of the storage compensation will be adjusted from the month following this change and will be done using the formula specific to subscription customers. The values of "winter consumption" and "annual consumption" will be calculated on the basis of the monthly statements of the T3 customer. Similarly, a change from a subscription option to a profiled option will result in a change in the modulation calculation method as early as the following month.

The projected value of the compensation base for 2024 will be specified in a subsequent deliberation of CRE, scheduled for early March 2024.

6.2.3.3 Calculation of the storage tariff term

The storage tariff term is calculated as the ratio between the estimated amount of the France network compensation and the estimated value of the basis for collecting this compensation. CRE will set the level of the storage term applicable on 1 April 2024 in March 2024 in order to take into account the revenues of the 2024-2025 commercialisation campaign.

6.2.4 Tariff multipliers for subscriptions to routing and delivery capacity for a period of less than one year

6.2.4.1 At Network Interconnection Points (IPs)

Capacity	Coefficient *(in parentheses: multiplier)*
Quarterly	1/3 of the annual term (x 1.33)
Monthly	1/8 of the annual term (x 1.5)
Daily	1/30 of the monthly term = 1/240 of the annual term (x 1.52)
Infra-daily	Prorata of daily term to remaining hours

6.2.4.2 To Methane Transport Terminal Interface Points (PITTM)

Capacity	Coefficient
Daily	1/ 365 of annual term

6.2.4.3 To Transport Storage Interface Points (PITS)

Capacity	Coefficient
Quarterly	1/ 3 of annual term
Monthly	1/ 8 of annual term
Daily	1/ 240 of annual term

6.2.4.4 As exit from the main network, on the regional network and for delivery

Capacity	Special conditions	Coefficient
Monthly	December - January - February	4/12 of annual term
	March - November	2/12 of annual term
	April – May – June – September – October	1/12 of annual term
	July – August	0.5/12 of annual term
Daily	Not applicable	1/30 of monthly term

- <u>Daily subscription on short notice of daily delivery capacities</u>

For customers connected to the GRTgaz and Teréga transmission network, special procedures apply for subscription requests for daily delivery capacities issued on short notice.

For GRTgaz, when the subscription request reaches GRTgaz with prior notice:

- between the standard notice stipulated in the contract for use of the GRTgaz transmission network and 9:00 am on the second working day preceding the day considered by the request, the applicable tariff is that specified in this tariff;
- after 9:00 a.m. on the second working day preceding the day considered by the request and before 8:00 p.m. on the day preceding the day considered by the request, the applicable rate is increased by 20%;
- after 8:00 p.m. the day before and until 2:00 p.m. the day considered by the request, the applicable rate is increased by 30%. A daily capacity subscribed during the day of delivery is considered to take effect from 6:00 a.m. that same day, regardless of the time at which it was subscribed.

For Teréga, the increases specified will only apply to subscriptions that took place after 5.59 a.m. the day before the day of delivery.

- Subscription of hourly delivery capacities

Hourly delivery capacities only apply to final consumers connected to the transmission network.

Any annual, monthly or daily subscription of daily delivery capacity entitles you to an hourly delivery capacity equal to 1/20th of the daily delivery capacity subscribed (except in special cases where this hourly capacity is not available).

To benefit, to the extent of the network's possibilities, from a higher hourly capacity, beyond the hourly capacity reserved through the annual, monthly or daily subscription of daily delivery capacity, the shipper must pay an additional price, equal to 10 times the sum of the daily delivery and transport capacity terms on the regional network.

6.2.5 Tariffs applicable to annual subscriptions for gas injection capacity on the transmission network from a gas production facility

6.2.5.1 For production transport interface points

The terms applicable to annual subscriptions to daily entry capacity on the GRTgaz network from the Transport Production Interface Points (PITP) are as follows:

for PITPs for which grid entry capacity is less than or equal to 5 GWh/d, the applicable term is 12.25 €/MWh/day per year;

for PITPs whose network entry capacity is greater than 5 GWh/d, the definition of the applicable term is the subject of a study and a specific decision.

6.2.5.2 For biomethane injection points[55]

The usage rate is specified in GRDF's ATRD7 deliberation.

Until ATRD7 takes effect, the terms of the injection fee defined in ATRT7 will continue to apply.

6.2.6 Tariffs of notional gas exchange points

The operating procedures of the notional gas exchange point (PEG) are defined by the TSOs, on the basis of objective and transparent criteria, and made public on their website.

The price of access to the gas exchange point includes:

- an annual fixed term, equal to 6,000 €;
- a term proportional to the quantities exchanged equal to 0.01 €/MWh.

Gas exchanges done on an electronic platform may be the subject of deliveries to a gas exchange point by an entity in charge of managing the compensation between the exchanges done on said electronic platform. Designations at the PEG of such an entity for the purposes of compensation, neutral with respect to the market, are not subject to the term proportional to the quantities traded.

[55] Or of renewable and low-carbon gas, as will be defined in the ATRD7 deliberation of GRDF

6.2.7 Intraday flexibility service for heavily modulated sites

The intraday flexibility service applies to customers connected to the transmission network that have a daily modulated volume greater than 0.8 GWh. No billing is issued for the intraday flexibility service.

For existing sites, GRTgaz evaluates this criterion on the basis of the consumption history of the previous year. For newly connected sites, this criterion is evaluated from the daily modulated volume on the operating days declared by the site, then on the basis of a quarterly assessment, with retroactivity over the past period as long as the criterion is met.

The operator of the site for which the intraday flexibility service is subscribed declares an hourly consumption profile to the TSO the day before for the next day and, if necessary, a new profile during the day, respecting the published notice periods. For any modification of the hourly consumption of the site that is less than ± 10% of its subscribed hourly capacity, the site benefits from a tolerance allowing it not to notify the TSO of its new hourly consumption profile.

No billing is issued for the Delivery Capacity Term for the relevant delivery point.[56]

6.2.8 Gas Quality Conversion

6.2.8.1 B-Gas to H-Gas Conversion Service

The service for converting gas B into gas H is accessible to shippers transporting their own gas B from IP Taisnières B and/or PITS North B, within the limit of the physical quantities of gas B concerned.

The tariff of the quality conversion service from B-gas to H-gas is as follows:

- for the interruptible annual offer, from a proportional term to the annual subscription of capacity equal to 29.63 €/MWh/day per year;
- for the interruptible monthly offer, from a proportional term to the monthly subscription of capacity equal to 3.70 €/MWh/day per month;
- for the firm daily offer, from a proportional term to the daily subscription of capacity equal to 0.24 €/MWh/day per day.
- for the interruptible daily offer, from a proportional term to the daily subscription of capacity equal to 0.21 €/MWh/day per day.

6.2.8.2 Penalty for daily balance sheet variance at scope B

Scope B is open to all shippers and is composed of Taisnières B, the North B storage, the advanced H gas to B gas converter, the B gas to H gas adapters and the delivery point of the H gas to B gas exchange service.

Shippers that use the gas B infrastructure have an assessment obligation at a daily time step over the B perimeter. Penalties apply in the event of non-compliance with their assessment obligation, short or long. The penalties that apply are as follows:

[56] For hourly capacity subscriptions and penalties for exceeding the capacities of SFM customers, the calculation takes into account the TCL applicable to the final consumer connected to the transmission network.

Assessment difference for scope B	Threshold	Price at Scope B
Positive assessment difference (long) below threshold	5 GWh	1 €/MWh
Positive assessment difference (long) above threshold		30 €/MWh
Negative assessment difference (short) below threshold	1 GWh	3.35 €/MWh
Negative assessment difference (short) above threshold		30 €/MWh

6.2.8.3 Control of designations on the physical infrastructures of network B

GRTgaz may, in circumstances where the physical balancing of network B so requires, impose that shippers that hold capacity on the physical infrastructure of transmission network B revise their designations on these infrastructure upwards or downwards.

6.2.9 In-line stock based balancing service

GRTgaz and Teréga commercialise a balancing service based on pipeline stock, whose subscription rate is equal to 0.12 €/MWh/d/month[57] for any industrial site delivery point directly connected to the transmission network or for any unprofiled site delivery point attached to a PITD. The subscription price of this service is subject to a 50% discount for any delivery point of a profiled site connected to a distribution network.

6.2.10 Penalties for exceeding capacity

6.2.10.1 Penalties for exceeding daily capacity

- Exceeding the daily exit capacity of the main network

For a given day, the daily capacity overrun value taken into account is equal to the difference, if positive, between the following two values:

- the difference between the daily quantity of gas delivered and the corresponding daily exit capacity of the main network, if this difference is positive, or zero if this difference is negative;
- the difference between the sum of the daily quantities delivered to the exit zone to "non-subscription" PDLs and the sum for the exit zone of the standard capacities for the "non-subscription" PDLs, if this difference is positive, or zero if this difference is negative.

- Exceeding daily regional transport and delivery capacity for final consumers connected to the transport network and RIPs:

For a given day, the daily capacity overrun value taken into account is equal to the difference, if positive, between the quantity of gas delivered and the daily delivery capacity subscribed.

- Exceeding daily regional transport and delivery capacity for PITDs

For a given day, the daily capacity overrun value taken into account is equal to the difference, if positive, between the following two values:

- the difference between the daily quantity of gas delivered and the corresponding daily delivery capacity, if this difference is positive, or zero if this difference is negative;
- the difference between the sum of the daily quantities delivered to "non-subscription" PDLs and the sum of standard capacities for the "non-subscription" PDLs, if this difference is positive, or zero if this difference is negative.

In case of exercise of interruptibility by the TSO, the above overrun calculations are performed by reducing the interruptible capacity of the interrupted part requested by the TSO.

[57] For the details of this service, see the Energy Regulation Commission deliberation of 9 September 2015 on evolution of the balancing rules on the gas transmission networks on 1 October 2015 and the Energy Regulation Commission deliberation of 15 September 2016 approving changes to the balancing rules of the natural gas transmission networks on 1 October 2016

- Methods for calculating penalties for exceeding daily capacity

Each day, overruns of daily capacity exits from the main transmission network to the regional network and delivery observed are subject to penalties.

For the part of the overrun less than or equal to 3% of the subscribed daily capacity, no penalty is charged.

For the part of the overrun greater than 3%, the penalty is equal to 20 times the price of the firm daily subscription of daily capacity.

TSOs give shippers the opportunity to quickly adjust their capacity subscriptions when a capacity overrun is observed, subject to network availability.

6.2.10.2 Penalties for exceeding hourly capacity

- Methods for calculating overruns

Each day, overruns of hourly capacity (i) of transport on the regional network and (ii) of delivery, for the supply of final consumers connected to the transport network, are subject to penalties. For a given day, the hourly capacity overrun is calculated by considering the maximum value of the hourly average of the quantities delivered to the delivery point concerned over four consecutive hours.

- Methods for calculating penalties for exceeding hourly capacity

For the part of the overrun less than or equal to 10% of the hourly capacity subscribed, no penalty is charged.

For the part of the overrun greater than 10%, the penalty is equal to 45 times the price of the daily subscription of hourly capacity.

Penalties for exceeding hourly capacity are not applied by GRTgaz if the shipper corrects its annual subscription for hourly capacity up to the level of the overrun observed.

6.2.11 Fee paid to GRTgaz by Fluxys for transport from the Dunkirk LNG terminal to the Belgian border

The *open season* conducted by GRTgaz between 2010 and 2011 in coordination with Fluxys allowed the launch of the necessary investments to create the Alveringem interconnection point. The entry capacities into Belgium from the Dunkirk LNG terminal are commercialised by Fluxys, and transport on the GRTgaz network is the subject of a service provided by GRTgaz to Fluxys.

In its deliberation of 12 July 2011[58], CRE indicated that, in view of the estimated costs of developing these capacities, the rate invoiced by GRTgaz to Fluxys for transport from the terminal to Belgium would be 45 €/MWh/d/year. CRE specified that this amount would be revised according to the actual level of investments.

In accordance with the aforementioned deliberation, CRE calculated the price of the service taking into account the costs at the end of the project. The price of the service is 51.48 €/MWh/d/year on 1 April 2024.

[58] Deliberation of the Energy Regulatory Commission of 12 July 2011 deciding on the conditions for connecting the Dunkirk LNG terminal to the GRTgaz network and on the development of a new interconnection with Belgium in Veurne

CRE's decision

CRE sets the tariff for use of the GRTgaz and Teréga natural gas transmission networks from 1 April 2024, according to the methodology and parameters stated in this deliberation.

CRE notably sets:

- the tariff regulation framework and incentive regulation parameters applicable to GRTgaz and Teréga for a period of approximately 4 years (part 2);
- the trajectory of operating expenses, the WACC and the projected evolution of the tariff (part 3);
- the structure of the tariff (part 4);
- the tariff terms applicable from 1 April 2024 (part 6).

The Energy Council, consulted by CRE on the draft decision, issued its opinion on 25 January 2024.

The deliberation will be published in the Journal Officiel de la République Française and on CRE's website It will be sent to the Minister for the Economy, Finance and Industrial and Digital Sovereignty.

Deliberated in Paris, 30 January 2024. -

For the Energy Regulation Commission,

The president,

Emmanuelle WARGON

APPENDIX 1: Summary table of the 2024 tariff schedule

This appendix summarises the main tariff terms presented in Part 6 of this deliberation.

Access to the Notional Gas Exchange Point (PEG)

Annual fixed term: **6,000 €/year**
Variable term: **0.01 €/MWh exchanged**

Main terms applicable to the Main Network

Entry to Network Interconnection Points (IP) (1 October 2024)	Capacity term (€/MWh/d/year)	
	Firm	Interruptible
GRTgaz - Taisnières B	**101.61**	50%
GRTgaz – Virtualys (Taisnières H)	**130.63**	50%
GRTgaz – Dunkirk	**130.63**	50%
GRTgaz – Obergailbach	**130.63**	50%
GRTgaz – Oltingue	**130.63**	50%
Teréga – Pirineos	**130.63**	75%

Exit at Network Interconnection Points (IP) (1 October 2024)	Capacity term (€/MWh/d/year)	
	Firm	Interruptible
GRTgaz – Virtualys (Alveringem)	**52.17**	
GRTgaz – Oltingue	**440.47**	85%
GRTgaz – Obergailbach	**443.25**	
Teréga – Pirineos	**580.15**	85%

Entry to LNG Terminal Interconnection Points (PITTM)	Capacity term (€/MWh/d/year)
	Firm
GRTgaz - Dunkerque LNG	**116.36**
GRTgaz - Montoir	**116.36**
GRTgaz - Fos	**116.36**
GRTgaz – Le Havre	**116.36**

Entry/Exit at Transport Storage Interface Points (PITS)	Capacity term (€/MWh/d/year)		
	Entry	Exit	
	Firm		Interruptible
GRTgaz - North West, North B, South East, North East, North B, Atlantic	10.88	28.52	50%
Teréga – Southwest	10.88	28.52	50%

Exit from the main network to the delivery points (TCS)	Capacity term (€/MWh/d/year)	
	Firm	Interruptible
GRTgaz	**124.42**	50%
Teréga	**124.42**	50%

Key Terms Applicable to Regional Networks

Transmission capacity on the regional network (TCR)	Capacity term (€/MWh/d/year)	
	Firm	Interrupti-ble
GRTgaz	**96,38 x NTR**	50%
Teréga	**102,60 x NTR**	50%

The Regional Tariff Level (NTR) is defined by delivery point from 0 to 10

Delivery capacity (TCL)	Capacity term (€/MWh/d/year)	
	Firm	Interrupti-ble
GRTgaz - Final consumer connected to the transmission network	**38.35**	50%
GRTgaz - RIP	**49.24**	
GRTgaz - PITD	**56.62**	
Teréga - Final consumer connected to the transmission network	**37.18**	50%
Teréga- PITD	**67.18**	

Delivery station	Term per station (€/station/year)
GRTgaz	**7,400.61**
Teréga	**4,112.46**

APPENDIX 2: Monitoring indicators of service quality

In application of the principles defined in the "Regulatory framework" part of this tariff decision, a quality of service monitoring mechanism is set up for both TSOs on the key areas of their activity. This monitoring consists of indicators sent each month by the TSOs to CRE and made public on their website.

Some indicators that are particularly important for proper functioning of the market are subject to a financial incentive system.

The following indicators are the subject of a financial incentive:

- quality of the quantities measured at the PITDs and sent to the GRDs the next day for calculation of the provisional allocations;
- quality of daily quantities remotely read at consumer delivery points connected to the transport network and sent the next day;
- quality of intra-day quantities remotely read at consumer delivery points connected to the transport network and sent during the day;
- quality of the overall end-of-day gas consumption forecasts done the day before and during the day.

The following indicators are monitored without a financial incentive:

- reliability of the planned pipeline stock indicator published by the TSOs on their public page;
- reduction of subscribed capacities;
- compliance with the annual maintenance program published in October and February by the TSO;
- compliance with the probable values published in October and February by the TSO;
- availability of the most useful information to shippers;
- handling of complaints:
- greenhouse gas emissions:
- greenhouse gas emissions related to the volume of gas transmitted;
- methane emissions related to the volume of gas transmitted;
- response time to detailed studies for project promoters;
- number of complaints following connection of the installations;
- time for installation and commissioning of a backhaul;
- compliance with connection deadlines for renewable and low-carbon gas production sites;
- suppressed volumes of renewable and low-carbon gases.

The service quality regulation system may change during the ATRT8 tariff period. It may be the subject of any audit that CRE deems useful.

The TSOs are authorised, during the commissioning of a major version of an application contributing to the production of certain indicators, to neutralise one day per year for calculation of said indicators. They are required to communicate to market participants, with one month's notice, the indicative date of commissioning, then to confirm the effective date of this commissioning one week in advance.

1. Indicators for monitoring the service quality of TSOs giving rise to a financial incentive

   a. Quality of the quantities measured at the PITDs and sent to the GRDs the next day for calculation of the provisional allocations

Calculation:	**Number of non-compliant days (1) per scope and per month** a value tracked by scope, i.e. a value tracked by GRTgaz and a value tracked by Teréga
Scope:	- all senders combined - all GRD combined - by scope

Tracked:	- calculation frequency: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Objective:	**GRTgaz:** - base objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month **Teréga:** - base objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month

Incentives:	**GRTgaz:**
	- penalties / month:
	  • 40 k€ for the 2nd non-compliant day;
	  • 60 k€ per non-compliant day, from the 3rd non-compliant day;
	- bonus / month: 50 k€ if the target objective is attained;
	- ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is limited to +/- 600 k€ per year.
	Teréga:
	- penalties / month:
	  • 20 k€ for the 2nd non-compliant day;
	  • 30 k€ per non-compliant day, from the 3rd non-compliant day;
	- bonus / month: 25 k€ if the target objective is attained;
	- ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is limited to +/- 300 k€ per year.

Date of implementation	- 1 April 2016

(1): For a given balancing zone (ZET), day D of month M is non-compliant if the difference, in absolute value, between the following values is strictly greater than 2%:

- *the provisional measurement of the quantity of gas delivered to all the PITDs of the ZET on day D and transmitted to the DSOs on day D+1 of month M;*
- *the final measurement of the quantity of gas delivered to all the PITDs of the ZET on day D and transmitted to the DSOs on the 20th of month M+1.*

b. Quality of daily quantities remotely read at consumer delivery points connected to the transport network and sent the next day

Calculation:	- **Rate of information of very good quality (4)** - **Rate of information of good quality** - **Rate of information of poor quality** (three values tracked for each of the TSOs)
Scope:	- all senders combined - All ZET combined - all remotely read industrial delivery points - rounded to one decimal place
Tracked:	- calculation frequency: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly

Incentives:	**GRTgaz:** The financial incentive relates to the monthly average of information rates of very good and poor quality. - penalties / month: 60 k€ per percent of poor quality information; - bonus / month: 1 k€ per percent of very good quality information; - ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is limited to 300 k€ for bonuses and 600 k€ per year for penalties. **Teréga:** The financial incentive relates to the monthly average of information rates of very good and poor quality. - penalties / month: 30 k€ per percent of poor quality information; - bonus / month: 500 € per percent of very good quality information; - ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is limited to 150 k€ for bonuses and 300 k€ per year for penalties.
Date of imple-mentation	- 1 April 2015

(4): Information is said to be of very good quality if the difference, in absolute value, between the measurement of the energy of day D transmitted on day D+1 and the definitive measurement of day D transmitted on M+1 is strictly less than 1%. If the difference is between 1% and 3% (respectively strictly greater than 3%), the value is of good quality (respectively of poor quality).

c. Quality of intra-day quantities remotely read at consumer delivery points connected to the transport network and sent during the day;

Calculation:	- **Rate of information of very good quality (1)** - **Rate of information of good quality** - **Rate of information of poor quality** (three values tracked by GRTgaz and Teréga per hour)
Scope:	- calculation for each hour of the day - all senders combined - All ZET combined - all remotely read industrial delivery points combined - rounded to the percent
Tracked:	- calculation frequency: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Incentives:	The financial incentive relates to the monthly average hourly information rates of very good and poor quality. **GRTgaz:** - penalties / month: 20 k€ per percent of poor quality information; - bonus / month: 1 k€ per percent of very good quality information; - Ceiling: the total annual amount, corresponding to the sum, over all times, of penalties to be paid and bonuses to be received by GRTgaz, is limited to +/- 600 k€ per year. **Teréga:** - penalties / month: 10 k€ per percent of poor quality information; - bonus / month: 500 € per percent of very good quality information; - Ceiling: the total annual amount, corresponding to the sum, over all times, of penalties to be paid and bonuses to be received by Teréga, is limited to +/- 300 k€ per year.
Date of imple-mentation	- 1 April 2014

(1): Information is said to be of very good quality if the difference, in absolute value, between the measurement of the energy of one hour of day D transmitted on day D and the definitive measurement of day D transmitted on M+1 is strictly less than 1%. If the difference is between 1% and 3% (respectively strictly greater than 3%), the value is of good quality (respectively of poor quality). If the difference is less than 100 kWh, the information is of very good quality.

d. Quality of the overall end-of-day gas consumption forecasts done the day before and during the day.

Calculation:	- **Rate of information of very good quality** (1) - **Rate of information of good quality** - **Rate of information of poor quality** (a rate per scope for the values published the day before and during the day, i.e. 3 values monitored by GRTgaz and 3 values monitored by Teréga)
Scope:	- all shippers combined - a value per per scope - rounded to one decimal place after the decimal point
Tracked:	- calculation frequency: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly - frequency of calculation of financial incentives: monthly
Incentives:	The financial incentive relates to the average of information rates of very good and poor quality. **GRTgaz:** For values published the day before (D-1) and during the day (D): - penalties: 80 € per tenth of a percent of poor quality information; - bonus: 20 € per tenth of a percent of very good quality information; - ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is limited to a total of +/- 600 k€ per year. **Teréga:** For values published the day before (D-1) and during the day (D): - penalties: 40 € per tenth of a percent of poor quality information; - bonus: 10 € per tenth of a percent of very good quality information; - ceiling: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by Teréga, is limited to a total of +/- 300 k€ per year.
Date of imple-mentation:	- 1 April 2014

(1): concerning the forecast done the day before, information is said to be of very good, good or poor quality, respectively, if the difference, in absolute value, between the following values is strictly less than 3%, respectively between 3% and 6% and strictly greater than 6%:

- *the consumption forecast for a given day published the day before at 5 p.m.;*
- *the final measurement of the energy consumed on day D transmitted on the 20th of M+1.*

Regarding the forecast done during the day, information is said to be of very good, good or poor quality, respectively, if the difference, in absolute value, between the following values is strictly less than 3%, respectively between 3% and 5% and strictly greater than 5%:

- *the consumption forecast for a given day published on that day at 3 p.m.;*
- *the final measurement of the energy consumed on day D transmitted on the 20th of M+1.*

The global end-of-day gas consumption forecasts used to calculate the indicator concern industrial customers, excluding heavily modulated sites, and public distributions connected to the TSO network.

2. Other indicators for monitoring the service quality of TSOs

a. Reliability of the planned pipeline stock indicator published by the TSOs on their public page

The indicator of projected pipeline stock is an estimate done by the TSOs of the level of gas in each scope at the end of the current gas day (5:00 a.m.). This indicator provides information on the grid voltage, as does the imbalance indicator. The difference between these two indicators lies in the view they give of the system: while the first offers a forecast view of the system for the current day, the second offers a static view, at a given time.

The interventions of TSOs on the markets is contingent on the indicator of projected pipeline stock; this indicator also informs shippers of the availability of flexibility services based on pipeline stock.

Calculation:	Percentage of hours, per month, for which the published planned pipeline stock is compliant. The projected pipeline stock published at time H is said to be non-compliant if at least one of the components that were used to calculate it is non-compliant(1) or if the result of the calculation is non-compliant. The main components of the calculation are: - consumption forecasts; - the quantities programmed; - the physical pipeline stock calculated at 6:00 a.m. This tolerance threshold is sized to isolate variations that cannot be the cause of customer rescheduling and/or consumption re-forecasting.
Scope:	- A value per month and per scope (a value for Teréga and a value for GRTgaz)
Tracked:	- calculation frequency: monthly - frequency of reporting to CRE: monthly - frequency of publication: monthly
Date of implementation:	- 1 April 2016

(1): A component is considered non-compliant if the deviation is both greater than 30 GWh and analysed as abnormal.

b. Maintenance Schedule Indicators

Indicator description	Calculation of indicator	Frequency of reporting to CRE and of publication	Date of implementation
Reduction of subscribed capacities	**Firm capacity made available during the work /firm capacity subscribed** (an aggregate value per type of points (1) connected to the network of each TSO)	Annual	1 April 2016
Compliance with the annual maintenance program published in October and February by the TSO	**Change (as a percentage) in the minimum capacity proposed in the maintenance program published in October and February and the capacity actually made available at the end of the year** (an aggregate value per type of points (1) connected to the network of each TSO)		1 April 2020
Compliance with the probable values published in October and February by the TSO	**Change (as a percentage) in the likely available capacity in the maintenance program published in October and February and the capacity actually made available at the end of the year** (one value per type of points 1) connected to the network of each TSO)		1 April 2020

(1): 3 categories of points are retained:

- *IPs in the dominant direction;*
- *entry to the PITTMs;*
- *entry and exit at PITS.*

The impact of maintenance which has become necessary at a superpoint will only be passed on to the points that make up said superpoint, by applying the formula:

Firm available capacity PI_i = Subscribed firm capacity PI_i x (1-Superpoint firm reduction rate)

where PI_i is a restricted point of the superpoint.

c. Monitoring the provision of the most useful information to shippers on the TSOs' websites

The information tracked by this indicator is as follows:

Information	Frequency of publication	Frequency of control	Threshold of quality	Date of implementation
Publication of production slips	Once a day at 1 pm	Once a day (publication or not of the information at 1 pm)	**Tracked value: rate of availability before 1 pm**	**1 April 2020**
Publication of scheduling notices	Once a day at 4 pm	Once a day (publication or not of the information at 4 pm)	**Tracked value: rate of availability before 4 pm**	
Publication of intra-day production notices	Once per hour with a lag of one hour	Once an hour (publication or not of the information at H+1:15	**Tracked value: rate of availability before H+1:15**	
Imbalance settlement price	Time, each time Powernext is updated	1 check per hour(1)	**Tracked value: monthly average of overall availability rates for each price** (weighted average price, marginal sale price, marginal purchase price)	
Short-term capacity sales	Once a day	Once a day (publication or not of the information at H-20 for sale at H	**Tracked value: rate of availability before H-20**	
Calls to localised *spreads*	Once a day	Once a day on D+1	**Tracked value: availability rate of the "Localised *Spreads*" page of GRTgaz and that of Teréga (Tetra) on D+1**	
Vigilance information on the state of the network	Once per hour with a lag of one hour	Once an hour (publication or not of the information at H+1:15)	**Tracked value: availability rate of the "Info vigilance" page of GRTgaz and that of Teréga (Tetra) before H+1:15**	

The indicator is reported monthly to CRE, and is calculated as the average of all these components.

d. Monitoring the quality of publications of information most useful to senders

Indicator description	Calculation of indicator	Frequency of reporting to CRE and of publication	Date of implementation
Substitution of measurements by *back-up data* (1) for data at PITDs	**Data announced as back-up by TSOs (in GWh) /*Back-up* data actually provided by TSOs (in GWh)** (a value tracked by TSO)	Monthly	1 April 2020

(1) Back-up data is sent by TSOs when data has not been sent by DSOs

e. Tracking of complaint processing

Indicator description	Calculation of indicator	Frequency of reporting to CRE and of publication	Date of implementation
Number of complaints	**Number of complaints per year**	Annual	1 April 2020
Complaint processing times	**Average time to process complaints (in days) depending on the level of complexity:** - **simple** - **complex** - **studies**		1 April 2020

f. Environmental indicators

Indicator description	Calculation of indicator	Frequency of reporting to CRE and of publication	Date of implementation
Greenhouse gas emissions	**Monthly Greenhouse gas emissions (equivalent in CO_2)** (a value tracked by TSO)	Annual	1 January 2009
Greenhouse gas emissions related to the volume of gas transmitted	**Monthly greenhouse gas emissions/Monthly Volume of gas routed** (a value tracked by TSO)		1 January 2009
Methane emissions related to the volume of gas transmitted	**Monthly methane emissions/Monthly volume of gas routed** (a value tracked by TSO)		1 April 2020

g. Biomethane Injection Indicators

Indicator description	Calculation of indicator	Frequency of reporting to CRE and of publication	Date of implementation
Response time to detailed studies for biomethane project promoters	**Average time between the date of receipt and the date of response to detailed study requests sent to GRDF related to the connection of a biomethane injection facility** (a value tracked by TSO)	Monthly	1 April 2024
Number of complaints following the connection of a biomethane installation	**Total number of producer complaints following the connection of a biomethane installation closed during month M** (a value tracked by TSO)	Monthly	1 April 2024
Time for commissioning of a backhaul	**Average completion time between approval for completion of CRE and commissioning of the backhaul** (a value tracked by TSO)	Annual	1 April 2024
Compliance with connection deadlines for renewable and low-carbon gas production sites	**Average time between the date of receipt of the request (milestone D1) and the date of commissioning of the production unit (milestone D8). The date deemed as proof for milestone D8 [is] the date of signature of the commissioning report (PV) by the operator** (a value tracked by TSO)	Annual	1 April 2024
Suppressed volumes of renewable and low-carbon gases	**Volume of renewable and low-carbon gases capped, by region / Maximum monthly capacity of injection projects, by region** (one value per region tracked per TSO)	Annual	1 April 2024

APPENDIX 3: Evolution of firm capacity subscriptions over the ATRT8 period

The forecasts of the evolution of the subscribed firm capacities at the entry points of the main network are presented below:

Evolution of firm annual subscribed capacities (GWh/d)	2024	2025	2026	2 027
PITTM Montoir	382	382	382	382
PITTM Fos	410	408	406	405
PITTM Dunkirk	366	366	382	366
PITTM Le Havre	110	110	110	110
IP Taisnières B	[confidential]	[confidential]	[confiden-tial]	[confidential]
IP Taisnières H (Virtualys)	233	233	195	93
IP Dunkirk	570	570	540	520
IP Obergailbach	299	299	236	40
IP Pirineos	236	240	240	240
PITS Atlantique	661	648	630	612
PITS Northwest	270	270	457	519
PITS Northeast	176	176	176	176
PITS North-B	158	125	29	0
PITS Southeast	647	649	645	639
PITS Southwest	556	556	556	556

The forecasts of evolution of the subscribed firm capacities at the exit points of the main network are presented below:

Evolution of firm annual subscribed capacities (GWh/d)	2024	2025	2026	2 027
IP Alveringem (Virtualys)	19	19	19	19
IP Oltingue	247	222	195	136
IP Obergailbach	30	30	30	30
IP Pirineos	83	78	58	0
PITS Atlantique	339	323	305	283
PITS Northwest	159	159	252	283
PITS Northeast	125	125	125	125
PITS North-B	75	75	19	0
PITS Southeast	96	112	116	115
PITS Southwest	301	301	301	301
Exit to GRTgaz regional network	3,697	3,622	3,493	3,377
Exit to Teréga regional network	310	300	290	282

APPENDIX 4: References for the annual update of the tariff for use of the natural gas transmission networks of GRTgaz and Teréga

i. Capital Charges

For years 2024 to 2027, the reference capital charges taken into account for updating the tariff schedule on 1 April of each year are those defined in the following table :

CCN forecast, in **M€$_{current}$**	2024	2025	2026	2 027
GRTgaz	1,074.3	1,080.4	1,067.4	1,064.5
Teréga	184.6	186.1	187.9	194.2

ii. Net operating expenses

For years 2024 to 2027, the reference net operating expenses taken into account are those defined in the following table:

CNE forecast, in **M€$_{current}$**	2024	2025	2026	2 027
GRTgaz	1,024.9	930.8	892.9	864.2
Teréga	76.6	77.6	79.3	80.5

For years 2025 to 2027, the amount taken into account at the time of the annual update of the tariff grid on 1 April of year N is equal to the reference value of year N:

− divided by the forecast inflation between year 2022 and year *N*;

	2023	2024	2025	2026	2 027
Forecast inflation between year 2022 and year *N*	4.80%	7.42%	9.57%	11.76%	13.77%

- multiplied, for years 2025, 2026 and 2027, by the real inflation rate between 2022 and year N-2. Real inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852), observed over calendar year N-2, compared to the average value of the same index observed over calendar year 2022;
- multiplied by the real inflation rate between year N-2 and year N-1, or else its best estimate, defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (INSEE reference 1763852);
- multiplied by the forecast inflation for year N, taken into account in the draft finance law for year N.

iii. Inter-operator flows

- Inter-GRT transfer for the national annual evolution of the tariff terms of the main network

As part of the annual evolution of the ATRT8 tariff, a $k_{national}$ coefficient was calculated to set the annual evolution of the tariff terms of the main network (see 2.3.4 of the ATRT8 Deliberation). It results in an opposite revenue gap between GRTgaz and Teréga. This gap is reversed between the TSOs.

- Inter-TSO transfers resulting from equalisation of the tariff terms of the main network

In the context of the ATRT8 tariff, a transfer from GRTgaz to Teréga allows each of the two operators to cover their respective charges associated with the main network, while ensuring equalisation of the tariff terms of the main network. The amount paid by GRTgaz to Teréga is as follows:

Annual transfer, in **M€**$_{\mathbf{currents}}$	2024	2025	2026	2 027
Transfer from GRTgaz to Teréga	0	0	8.0	32.1

iv. Annual difference between forecast revenue and forecast allowed revenue

A smoothing term, making it possible to take into account the annual difference between the forecast revenues and the forecast allowed revenue, for which the updated value at the risk-free rate at 3.8% is null over the period of the ATRT8 tariff, is added to the allowed revenue of the operators according to the following chronicles:

Annual difference, in **M€**$_{\mathbf{current}}$	2024	2025	2026	2 027
GRTgaz	-107.0	71.8	63.3	-21.5
Teréga	4.4	8.3	2.0	-18.0

v. Calculation and clearance of the CRCP balance

The overall balance of the CRCP is equal to the amount to be paid or deducted from the CRCP for the past year and the previous year, plus the balance of the unpaid CRCP for previous years.

The amount to be paid or deducted in the CRCP is calculated by CRE, for each year elapsed, according to the deviation from the realised, for each item concerned, compared to the reference amounts defined below. All or part of the difference is paid to the CRCP, the share is determined according to the coverage rate provided for by this deliberation.

GRTgaz, in **M€**$_{\mathbf{current}}$	Rate	2024	2025	2026	2 027
Routing revenue "100% CRCP"	100 %	**1,540.8**	**1,599.1**	**1,572.3**	**1,546.9**
Routing revenue "Upstream"	100 %	**-**	**459.6**	**434.1**	**365.3**
	90%	**427.9**	Updated annually	Updated annually	Updated annually
Surplus revenue from capacity auctions	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Revenue from penalties for capacity overruns	100 %	**5.5**	**5.4**	**5.2**	**5.1**
Normative capital charges "infrastructures"	100 %	**954.4**	**956.1**	**941.6**	**942.8**
Reference for the calculation of differences in capital charges "excluding infrastructure" due to inflation	100 %	**119.9**	**124.3**	**125.9**	**121.7**
Charges for motive energy and gap between revenues and expenses related to CO_2 quotas	100 %	**-**	**165.1**	**140.2**	**118.2**
	90 %[59]	**203.1**	Updated annually	Updated annually	Updated annually
Charges for consumables	100 %	**-**	**6.8**	**6.9**	**7.1**
	80%	**6.7**	Updated annually	Updated annually	Updated annually
ANE expense deviations related exclusively to price deviations from the electricity and gas price reference adopted by CRE	100% of the price effect	**30.4**	**27.4**	**29.1**	**26.9**
CCCG and TAC connection revenues	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Revenue from connection of biomethane units	100 %	**12.7**	**13.5**	**14.3**	**15.2**
Revenue from connection of GNV station units	100 %	**0.9**	**0.9**	**1.0**	**1.0**

[59] The coverage is 90% for the fraction of the difference between the realised and the forecast trajectory less than or equal to 50% (in absolute value) of the forecast trajectory, and 100% beyond.

Revenue from services for third parties related to major land use planning projects (excluding third-party participation in connections)	100 %	**18.8**	**26.5**	**21.9**	**26.4**
Expenses for the H-B conversion service	100 %	**151.6**	**76.0**	**51.9**	**43.2**
Charges and revenues resulting from congestion resolution mechanisms	100 %	**7.9**	**7.1**	**6.2**	**5.4**
Charges related, where applicable, to remuneration by the TSOs of consumers connected to the transmission networks that have signed an interruptibility contract on the basis of article L.431-6-2 of the Energy Code	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Charges relating to the contract between GRTgaz and Teréga	100 %	**38.7**	**39.6**	**40.4**	**41.1**
Charges and revenue associated with contracts with other regulated operators (notably storage operators)	100 %	**15.0**	**14.7**	**12.1**	**12.0**
Reimbursement made by the DSOs to the TSOs for the share of the biomethane injection term collected from producers connected to the distribution network intended to cover the OPEX associated with the TSOs' backhauls (revenue)	100 %	Defined in ATRD7 deliberation	Defined in ATRD7 deliberation	Defined in ATRD7 deliberation	Defined in ATRD7 deliberation
Interoperator flows between GRTgaz and Teréga linked to evolution of the $k_{national}$ factor	100 %	**-**	Updated annually	Updated annually	Updated annually
Expenses related to studies not continued for major projects that have been the subject of prior approval by CRE or other stranded costs handled on a case-by-case basis, for which CRE approves coverage	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Gain on disposal of assets (real estate or land)	80%	**0.0**	**0.0**	**0.0**	**0.0**
Bonuses and penalties resulting from incentive regulation mechanisms	100 %	**0.0**	**0.0**	**0.0**	**0.0**
R&D charges	100% of unused charges at the end of the period	**31.4**	**31.6**	**30.9**	**30.9**

Furthermore, with regard to net operating expenses, for the years 2024 to 2027, the amount taken into account for calculation of the CRCP balance takes into account the difference between projected inflation and actual inflation.

This amount is equal to the reference value for year *N*:

- divided by the forecast inflation between year 2022 and year *N*;

	2023	2024	2025	2026	2 027
Forecast inflation between year 2022 and year *N*	4.80%	7.42%	9.57%	11.76%	13.77%

- multiplied by the real inflation between year 2022 and year *N*. Real inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852), observed over calendar year *N*, compared to the average value of the same index observed over calendar year 2022.

Teréga, in **M€current**	Rate	2024	2025	2026	2 027
Routing revenue "100% CRCP"	100 %	**180.6**	**186.9**	**184.9**	**183.3**
Routing revenue "Upstream"	100 %	**-**	**84.3**	**75.5**	**40.5**
	90%	**84.2**	Updated annually	Updated annually	Updated annually
Surplus revenue from capacity auctions	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Revenue from penalties for capacity overruns	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Normative capital charges "infrastructures"	100 %	**164.5**	**168.2**	**170.2**	**176.9**
Reference for the calculation of differences in capital charges "excluding infrastructure" due to inflation	100 %	**20.1**	**18.0**	**17.6**	**17.3**
Deviations from the reference trajectory of the "TOTEX" experiment	50%	**24.6**	**24.5**	**24.6**	**24.5**
Charges for motive energy and gap between revenues and expenses related to CO_2 quotas	100 %	**-**	**10.4**	**11.8**	**11.4**
	90 %[60]	**9.7**	Updated annually	Updated annually	Updated annually
Charges for consumables	100 %	**-**	**0.2**	**0.2**	**0.2**
	80%	**0.2**	Updated annually	Updated annually	Updated annually
CCCG and TAC connection revenues	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Revenue from connection of biomethane units	100 %	**1.0**	**1.0**	**1.0**	**1.0**
Revenue from connection of GNV station units	100 %	**0.0**	**0.1**	**0.0**	**0.1**
Revenue from services for third parties related to major land use planning projects (excluding third-party participation in connections)	100 %	**0.1**	**0.1**	**0.1**	**0.1**
Charges and revenues resulting from congestion resolution mechanisms	100 %	**1.1**	**1.0**	**0.9**	**0.7**
Charges related, where applicable, to remuneration by the TSOs of consumers connected to the transmission networks that have signed an interruptibility contract on the basis of article L.431-6-2 of the Energy Code	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Revenue relating to the contract between GRTgaz and Teréga	100 %	**38.7**	**39.6**	**40.4**	**41.1**
Charges and revenue associated with contracts with other regulated operators (notably storage operators)	100 %	**5.6**	**5.5**	**5.7**	**5.8**
Reimbursement made by the DSOs to the TSOs for the share of the biomethane injection term collected from producers connected to the distribution network intended to cover the OPEX associated with the TSOs' backhauls (revenue)	100 %	**0.0**	**0.0**	**0.0**	**0.0**
Interoperator flows between GRTgaz and Teréga linked to evolution of the $k_{national}$ factor	100 %	-	Updated annually	Updated annually	Updated annually
Expenses related to studies not continued for major projects that have been the subject of prior approval by CRE or other stranded costs	100 %	**0.0**	**0.0**	**0.0**	**0.0**

[60] The coverage is 90% for the fraction of the difference between the realised and the forecast trajectory less than or equal to 50% (in absolute value) of the forecast trajectory, and 100% beyond.

handled on a case-by-case basis, for which CRE approves coverage					
Gain on disposal of assets (real estate or land)	80%	**0.0**	**0.0**	**0.0**	**0.0**
Bonuses and penalties resulting from incentive regulation mechanisms	100 %	**0.0**	**0.0**	**0.0**	**0.0**
R&D charges	100% of unused charges at the end of the period	**2.7**	**2.8**	**2.2**	**2.3**

Furthermore, with regard to net operating expenses, for the years 2024 to 2027, the amount taken into account for calculation of the CRCP balance takes into account the difference between projected inflation and actual inflation.

This amount is equal to the reference value for year *N*:

- divided by the forecast inflation between year 2022 and year *N*;

	2023	2024	2025	2026	2 027
Forecast inflation between year 2022 and year *N*	4.80%	7.42%	9.57%	11.76%	13.77%

- multiplied by the real inflation between year 2022 and year *N*. Real inflation is defined as the change in the average value of the consumer price index excluding tobacco, as calculated by the INSEE for all households in France (referenced INSEE 1763852), observed over calendar year *N*, compared to the average value of the same index observed over calendar year 2022.

vi. Evolution of the storage tariff term

The evolution of the storage tariff term is done according to the procedures specified in the ATRT8 tariff according to the allowed revenues of Storengy, Teréga and Géométhane, and the provisional auction revenues.

APPENDIX 5: Terms of calculation of references for the update of energy Benefit charges

[Confidential Appendix]

APPENDIX 6: List of NTRs by site

Appendix published on CRE's website for GRTgaz and Teréga.

APPENDIX 7: Information to be published in the framework of the tariff network code

<table>
<tr><th>Article</th><th>Information to be published</th><th>Publishing</th></tr>
<tr><td>29(a)
29(b)</td><td>(a) for standard firm capacity products:
i. the reserve prices applicable at least until the end of the gas year starting after the annual capacity auction;
ii. multipliers and seasonal factors applied to reserve prices for non-annual capacity standard products;
iii. the justification of the national regulatory authority with regard to the level of multipliers;
iv. if seasonal factors are applied, the justification for their application;
b) for standard interruptible capacity products:
vii. the reserve prices applicable at least until the end of the gas year starting after the annual capacity auction;
viii. an assessment of the likelihood of interruption, including:
1. a list of all standard interruptible capacity product types offered, including the respective probability of interruption and the level of discount applied;
2. an explanation of how the probability of interruption is calculated for each type of product referred to in point 1);
3. the historical or forecast data, or both, used to estimate the probability of interruption mentioned in point 2).</td><td>(a) for standard products of firm capacity:
i. the tariff terms are indicated in section 6.2.2
ii. applicable multipliers are indicated in section 6.2.4
iii. the justification is indicated section 6.2.4
iv. N/A
b) for standard interruptible capacity products:
i. Standard interruptible capacity products and the level of applicable discounts are shown in section 6.2.2
ii. the details of the interruption probabilities are explained in 4.2.3.</td></tr>
<tr><td>30(1)(a)</td><td>Information on the parameters used in the applied reference price calculation method that are related to the technical characteristics of the transmission network, such as:
i. the technical capacity at the entry and exit points and the corresponding assumptions;
ii. the forecast subscribed capacity at the entry and exit points and the corresponding assumptions;
iii. the structural representation of the transmission network with an appropriate level of detail;
v. additional technical information about the transmission network, such as the length and diameter of the pipelines and the power of the compressor stations.</td><td>• The distances taken into account are indicated in Appendix 9.
• The estimated subscribed capacities at the entry and exit points are indicated in section 4.2.2.
• Data on technical capacity as well as all technical information are published on the TSO sites according to the ENTSOG model
• The structural representation of the transmission network is published on the TSO sites.</td></tr>
<tr><td>30(1)(b)</td><td>i. the authorised or projected revenue, or both, of the transmission system operator;</td><td>• Information on capital expenditures, operating expenses and allowed</td></tr>
</table>

	ii. the information related to year-to-year changes in the revenue specified in point (i); iii. the following parameters: a. the types of assets included in the regulated asset base and their aggregate value; b. the cost of capital and its method of calculation; c. capital expenditures, including: i. the methodologies used to determine the initial value of the assets; ii. methodologies used to revalue assets; iii. explanations on evolution of the value of assets; iv. depreciation periods and amounts depreciated by type of asset; d. operational expenses; e. incentive mechanisms and efficiency objectives; f. the Inflation indices; iv. revenue associated with transport services; a. the entry-exit distribution; b. the internal distribution of the system-between systems. v. information on clearance of the accrual account (the revenue actually obtained, the revenue recovery deficit or surplus, the share of this recorded in the CRCP, and the period of clearance) vi. the intended use of the bidding bonus.	revenues is provided in sections 3.1 and 3.3 • The information relating to the incentive measures, and functioning of the CRCP, is indicated in part 2 • the entry-exit distribution of transport service revenue is 34% (entries)/66%(exits), and is detailed in section 4.2.2.1.4 • the distribution of revenues from transport services between transit and domestic consumption is about 17% for transit and 83% for domestic consumption. • Information on the intended use of the bidding premium is given in section 2.4.2
30(1)(c)	i. where applied, the ancillary service rates for ancillary services ii. the reference prices and other prices applicable to points other than those mentioned in article 29	The prices of the ancillary services and all the prices applicable to the various points are indicated in part 6
30(2)	• explanations of differences in tariff levels between 2 tariff periods • a simplified tariff model	• Differences between tariff levels between 2023 and tariffs over the ATRT8 period are shown in section 6.2.2. The explanatory elements of these differences are developed in parts 2, 3 and 4 • The simplified model is published on CRE's website (Appendix 10)

APPENDIX 8: Comparison with the capacity weighted distance method of the tariff network code

The Tariff network code describes, in detail in article 8, a method for calculating reference prices at entry and exit points based on subscribed capacities, distances travelled by gas as weighting factors, and combinations of entry and exit points in relevant flow scenarios (*capacity weighted distance reference price methodology (CWD))*.

The code provides that the method of calculating the reference prices chosen by each regulator is compared to this CWD method. Here, CRE presents the grid that would result from strict application of this method:

€/MWh/d/year	CWD Entries	CWD Exits
IP Virtualys	190.56	
IP Taisnières B	148.64	
IP Dunkirk	190.56	
IP Obergailbach	190.56	313.00
IP Oltingue	190.56	311.46
IP Pirineos	190.56	388.68
PITTM Dunkirk	169.75	
PITTM Montoir	169.75	
PITTM Fos	169.75	
PITTM Le Havre	169.75	
Regional network exit		96.85
PITS	15.87	21.74

The parameters of the reference price calculation method based on capacity and distance as weighting factors are close to those of CRE's method. The main difference with CRE's method is the use of a 50/50 ratio for the distribution of revenue between entries and exits. In fact, CRE considers that the application of a 50/50 distribution is not appropriate in view of the particular configuration of the French network.

Moreover, the CWD method aims, in spirit, to obtain homogeneous unit costs (€/MWh/d/year/km) for the different users of the gas transmission network. However, its practical application, since the same entry point can supply several exit points, does not necessarily lead to this result. Here, the France-Switzerland and France-Germany unit cost totals 0.73 €/MWh/d/year/km compared to 0.68 €/MWh/d/year/km for France-Spain, and 0.87 €/MWh/d/year/km for the supply of domestic customers.

The "$Comp_{cap}$" ratio as provided for by article 5 of the Tariff Network Code would be 18.4%.

APPENDIX 9: List of flow scenarios

Appendix published on CRE's website.

APPENDIX 10: Simplified tariff file

Appendix published on CRE's website.

APPENDIX 11: Compliance with article 5 of the tariff network code

Article 5 of the tariff network code provides for an assessment of the distribution of transmission network costs between the supply of cross-border outlets and national consumers, with the aim of limiting cross-subsidies between these uses. This appendix presents the detailed calculations of this evaluation, which are summarised in section 4.2.2.2.2.e of the deliberation.

As a reminder, the estimated capacity subscriptions retained by CRE are, on average over the ATRT8 period, as follows (see 4.2.2.2.2.b of the deliberation):

Entry points	(GWh/d/year)	
IP	1255	Or 2524.3 GWh/d/year on IPs and PITTM
PITTM	1269.3	
PITS	2472	
Exit points	**(GWh/d/year)**	
IP Pirineos	54	Or 303 GWh/d/year on cross-border exits
IP Oltingue	200	
IP Obergailbach	30	
IP Virtualys	19	
PITS	1110	
Output to regional network	3870	

Article 5(5) of the Tariff Network Code provides that:
"*The revenue associated with transport services to be recovered for use of the internal network of a system at the points of entry referred to in point (a) of paragraph 3 and point (a) of paragraph 4 shall be calculated as follows:*

a) *the volume of capacity allocated or, respectively, flows associated with providing transport services for use of the network to serve adjacent systems at all points of entry is presumed to be equal to the volume of capacity or, respectively, flows allocated to providing transport services for use of the network to serve adjacent systems at all points of exit;*
b) *the capacity and, respectively, the flows, determined as indicated in point a) of this paragraph, are used to calculate the revenue to be recovered, associated with the transport services for use of the network for the service of the systems adjacent to the points of entry;*
c) *the difference between the total revenue associated with transport services to be recovered at the ports of entry and the resulting value indicated in point (b) of this paragraph is equal to the revenue associated with transport services to be recovered for use of the system's internal network at the ports of entry.* "

In accordance with points (a) and (b), CRE considers that 303 GWh/year are reserved for entries to supply cross-border exits (when reservations of up to 303 GWh/year are foreseen). This is why CRE states in its deliberation (see 4.2.2.2.2.e) that "*The supply by a user of a cross-border exit up to 1 MWh/day/year requires the subscription of 1 MWh/day/year of entry capacity in France (IP/PITTM)*".

In its deliberation (4.2.2.2.2.e), CRE indicates that "*The supply of 1 MWh/d/year of a national customer requires, on average, taking into account the subscriptions of storage capacities, the subscription of 0.57 MWh/d/year of entry capacities in France (IP/PITTM), and 0.64 MWh/d/year of entry capacity (extraction) at the PITS. These ratios are calculated on the basis of subscribed capacities (on average over the ATRT8 period). In addition, the subscription of 0.64 MWh/d/year of entry capacity at the PITS (extraction) requires the subscription of 0.29 MWh/d/year of exit capacity (injection) at the PITS (on average over the ATRT8 period).* "
In fact, in accordance with point (c), CRE considers that the entry reservations not used to supply cross-border exits are dedicated to the supply of exits to domestic consumers, i.e. 2524.3 – 303 = 2240.3 GWh/d/year. The

ratio of 0.57 is obtained by dividing these entry capacity subscriptions by exit reservations to domestic consumers (i.e. 2221.3/3870).
In addition, CRE considers that storage facilities are only used by domestic users. The last two reservation ratios, namely 0.64 MWh/d/yr inbound from storage and 0.28 MWh/d/yr outbound to storage, are obtained by dividing, respectively, the inbound reservations from storage facilities (2,472 GWh/d/yr) and the outbound reservations to storage facilities (1,110 GWh/d/yr) by the planned reservations to domestic consumers (3,870 GWh/d/yr).

The unit cost to supply domestic consumers is calculated as follows:

$$Ratio_{Cap}^{intra} = \frac{Revenue_{cap}^{intra}}{Driver_{cap}^{intra}}$$

$$= \frac{Revenu_{Entrées\ (PIR\ et\ PITTM)\ vers\ Conso\ Nat} + Revenu_{Entrées\ (PITS)} + Revenu_{Sorties\ (PITS)} + Revenu_{Sorties\ Conso\ Nat}}{Distance\ moyenne_{vers\ Conso\ Nat} \times Souscriptions_{sorties\ vers\ Conso\ Nat}}$$

$$= \frac{TCE_{Moyenne\ PIR\ et\ PITTM} \times Souscriptions_{Entrées\ vers\ conso\ nat}^{PIR\ et\ PITTM} + TCES \times Souscriptions_{Entrées}^{PITS} + TCSS \times Souscriptions_{Sorties}^{PITS} + TCS \times Souscriptions_{sorties\ vers\ Conso\ Nat}}{249 \times 3\,870}$$

$$= \frac{122{,}9 \times 2\,221{,}3 + 10{,}9 \times 2\,472 + 28{,}5 \times 1\,110 + 124{,}4 \times 3\,870}{249 \times 3\,870}$$

$$= \frac{\left(122{,}9 \times \frac{2\,221{,}3}{3\,870} + 10{,}9 \times \frac{2\,472}{3\,870} + 28{,}5 \times \frac{1\,110}{3\,870} + 124{,}4 \times \frac{3\,870}{3\,870}\right) \times 3\,870}{249 \times 3\,870}$$

$$= \frac{(122{,}9 \times \mathbf{0.57} + 10{,}9 \times \mathbf{0.64} + 28{,}2 \times \mathbf{0.29} + 124{,}4) \times 3\,870}{249 \times 3\,870} = 0.84\ €/MWh/d/y/km$$

Where:

- $Revenue_{cap}^{intra}$ is the revenue, defined in a monetary unit such as the euro, obtained from capacity tariffs billed for use of the network internal to a system;
- $\mathrm{Driver}_{cap}^{intra}$; is the value of the cost factor(s) in relation to the capacity for use of the internal system network, such as the sum of the average forecast daily capacities subscribed at each point or group of internal system entry and exit points; it is defined in a unit of measurement such as MWh/day. <u>The cost drivers considered by CRE are capacity and distance</u>;
- TCE: tariff term of IP or PITTM entry;
- TCES: entry tariff term from the PITS (extraction);
- TCSS: exit tariff term to the PITS (injection);
- TCS: exit tariff term to the regional network (i.e. to national consumers).

The unit costs to supply the cross-border exits Obergailbach, Oltingue and Pirineos are calculated as follows:

$$Ratio_{cap}^{cross} = \frac{\mathrm{Revenue}_{cap}^{cross}}{\mathrm{Driver}_{cap}^{cross}} = \frac{(\text{termes d'entrée} + \text{termes de sorties}) * \text{capacités de sortie transfrontalière}}{distances\ d'alimentation\ de\ la\ sortie\ transfrontalière * Capacités}$$

In the case of the Obergailbach exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Obergailbach}) * 30\,000}{30\,000 * 672} = 0{,}84$$

In the case of the Oltingue exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Oltingue}) * 200\,000}{200\,000 * 669} = 0{,}84$$

In the case of the Pirineos exit:

$$= \frac{(TCE_{\ PIR/PITTM} + TCST_{\ Pirineos}) * 54\,000}{54\,000 * 835} = 0{,}84$$

With:

- $\mathrm{Revenue}_{cap}^{cross}$ is the revenue, defined in a monetary unit such as the euro, obtained from the capacity tariffs billed for use of the network for the service of adjacent systems;

- $\mathrm{Driver}_{cap}^{cross}$ is the value of the cost factor(s) of the capacity for network use serving adjacent systems, such as the sum of the average forecast daily capacities subscribed at each point or group of entry and exit points between systems; it is defined in a unit of measurement such as MWh/day. The cost drivers considered by CRE are capacity and distance;
- TCE: tariff term of IP or PITTM entry;
- TCST: tariff term of IP exit.

Therefore, the unit costs to supply domestic consumers and cross-border exits are identical. There are no cross-subsidies.

$$Comp_{cap} = \frac{2 * (Ratio_{cap}^{intra} - Ratio_{cap}^{cross})}{Ratio_{cap}^{intra} + Ratio_{cap}^{cross}} = \frac{2 * (0{,}84 - 0{,}84)}{0{,}84 + 0{,}84} = 0$$