DELIBERATION

Deliberation of the French Energy Regulatory Commission of 15 December 2016 forming a decision on the tariff for the use of GRTgaz and TIGF natural gas transmission networks

Present: Philippe de Ladoucette, Chairman, Christine Chauvet, Catherine Edwige and Jean-Pierre Sotura, Commissioners.

The tariff for the use of GRTgaz and TIGF natural gas transmission networks, known as "ATRT6", takes effect on 1st April 2017 for a period of approximately four years. It was adopted after a broad consultation of interested parties and following studies that were made public.

The ATRT6 tariff offers all stakeholders visibility of changes to the tariff between 2017 and 2021 and encourages the transmission system operators (TSOs) to improve their efficiency both with respect to controlling their costs and to the service quality provided to their network users.

The ATRT6 tariff provides the TSOs with all the resources needed to respond to the challenges of energy transition and takes account of the changes in the gas market

The ATRT6 tariff increases the capacity of the TSOs to participate in energy transition whilst fulfilling their public service mission, particularly through the "GRTgaz 2020" project and TIGF's "research and innovation" project.

The ATRT6 tariff brings substantial changes to the tariff structure, the main purpose being to prepare the creation of a single marketplace in France by 2018, in line with the network code principles that harmonise the transmission tariffs structures in the European Union (known as the "Tariffs Network Code"). In particular, these changes have resulted in a reduction, as from 1st April 2017, in the main network tariff system of around 10% for entry points in France (pipelines and LNG terminals) and exit points from the main network to the regional network.

The current method for determining the Regional Tariff Level (NTR - Regional Tariff Level) leads to very substantial discrepancies in the transmission tariff between the delivery points in France, compared with other European countries. With regard to the outgoing regulated sale tariffs which in the past have operated on an equalising basis with the effect of offsetting the consequences of these NTR discrepancies, this situation could lead to disconnections. The ATRT6 tariff therefore provides for a capping of the NTR at 10, as from 1st April 2017.

These changes form part of the gas transmission tariff level control in France

The ATRT6 tariff will decrease on 1st April 2017, mainly due to the reduction in the cost of capital, before increasing moderately over the following years, mainly because of the costs associated with the creation of the single marketplace:

- the average GRTgaz tariff will fall by -3.1% in 2017, excluding changes in the tariffs' structure and inter-operator compensation mechanism effects. The change to the average tariff over the ATRT6 period is equivalent to a -0.4% fall per year;
- the average TIGF tariff will fall by -2.2 % in 2017, excluding changes in the tariffs' structure and inter-operator compensation mechanism effects. The change to the average tariff over the ATRT6 period is equivalent to a +0.8 % increase per year.

TSO performance incentives are reinforced: introduction of a "non-network" incentive on capital expenditure, reinforcement of incentives on the costs of the main network development projects and on the quality of service provided for the users.

Finally, the ATRT5 tariff provided for a 3% bonus over 10 years, which was granted to a limited number of projects. Against the current background of decreasing demand and overcapacity on the European market, the ATRT6 provides for a new incentive regulation mechanism that introduces a bonus whose allocation and amount will depend on the results of a cost/profit analysis carried out by CRE (French Energy Regulatory Commission).

The current access tariff for GRTgaz and TIGF natural gas transmission networks, known as "ATRT5", has been applied since 1st April 2013, in application of CRE's resolution of 13th December 2012[1].

LEGAL FRAMEWORK

Article L.134-2(4) of the energy code authorises CRE to specify "*the conditions of use of the natural gas transmission and distribution networks [...] including the methodology for establishing tariffs for use of these networks [...] and the tariff changes*".

Articles L.452-1 to L.452-3 of the energy code determine CRE's tariff-related competencies.

Article L.452-1 states in particular that these tariffs "*are determined in a transparent and non-discriminatory manner so as to cover all the costs borne by these operators insofar as these costs correspond to those of an efficient network or facilities operator. These costs take account of the features of the service provided and of the costs linked to this service, including obligations established by law and regulations, as well as costs resulting from the execution of public service and contract assignments mentioned at I in article L. 121-46*".

Article L.452-2 stipulates that CRE sets the methods used to establish the tariffs for use of natural gas networks.

Furthermore, article L.452-3 of the energy code states that CRE decides on tariff changes *"with, if necessary, tariff level and structural changes that it considers justified, specifically with regard to the analysis of operators' accounting systems and foreseeable changes to operating and investment expenses"*. CRE's resolution may make provision for "*a framework over many years covering tariff changes as well as appropriate short- or long-term incentives to encourage the operators to improve their performances with regard in particular to the quality of service supplied, the integration of the domestic gas market, the reliability of the supply and the search for improvements of productivity*".

Through this resolution, CRE defines the method for setting the access tariffs for GRTgaz and TIGF natural gas transmission networks and establishes the tariff known as "ATRT6".

ATRT6 TARIFF FORMULATION PROCESS

A tariff prepared on a broad consultation base

Bearing in mind the need for visibility expressed by the interested parties and the complexity of the issues to be dealt with, work on formulating the ATRT6 tariff started at the beginning of 2016. CRE led a broad consultation with all stakeholders. It held two public consultations, arranged numerous hearings, particularly with GRTgaz and TIGF as well as their shareholders and held a round table.

This schedule and broad consultation provided all the stakeholders with the visibility and forecasting capacity required for successful operations of the gas market.

External reports ordered by CRE as part of the ATRT6 tariff formulation, have been published.

Date of entry into force and validity period of the ATRT6 tariff

The ATRT6 tariff will take effect from 1st April 2017 and will be applied for a period of approximately 4 years. All stakeholders agree with these arrangements.

Energy policy orientations

In application of the provisions of article L.452-3 of the energy code, CRE has taken account of the energy policy orientations issued by correspondence of 28th July 2016 from the Minister of the Environment, Energy and Seas, responsible for international relations on climate. These orientations relate in particular to the development of new gas uses, the integration of gas marketplaces, the end of L gas supplies, reform of the regional tariff levels (NTR) and the development of interruptibility services. These lines of development may be consulted on CRE's website[2].

MAIN DEVELOPMENTS COVERED BY THE ATRT6 TARIFF

Based on feedback from the ATRT5 tariff, whilst adding to it, CRE has reiterated the existing regulatory framework so as to encourage the TSOs to improve their efficiency with regard to controlling their costs and quality of service offered to the users.

Consideration of the challenges of energy transition and the future of natural gas transmission networks

Gas is a substitutable form of energy and consumers are being encouraged to make a choice between it and other sources of energy, based on the economic climate and the competitiveness of the market. European and French consumption of natural gas has reduced over the last ten years under the triple effect of efforts to control energy consumption, the economic crisis and the low level of electricity generation using gas. Furthermore, the law of

[1] Resolution of 13th December 2012 forming a ruling on the access tariff for natural gas transmission systems
[2] Communication from the Minister of the Environment, Energy and the Seas on the energy policy orientations

17th August 2015 relating to energy transition for green growth (LTECV)[3] has introduced an objective to reduce consumption of fossil energy by 30% between 2012 and 2030, detailed in article 2 of the multi-year energy programme (PPE)[4], which sets out in particular the following objectives for reducing consumption of natural gas from 2012: - 8.4% in 2018 and - 15.8% in 2023.

Against this background, CRE has taken into account the request of the TSOs to strengthen their capacity for participating in energy transition and to prepare the future of gas transmission networks, through the GRTgaz project, "GRTgaz 2020" and the TIGF "research and innovation" project. These additional resources will support in particular the substitution of the use of petroleum products in industry and transport with that of natural gas, the development of the biomethane sector and new uses of natural gas.

In addition, the ATRT6 tariff introduces measures to promote the connection of new customers and maintain existing customers, with the aim of controlling gas transmission tariffs:

- assuming up to a 50% share of the costs of connecting new customers through a "development discount" that could in particular apply to the connection of vehicle natural gas stations or bio natural gas for vehicle stations;
- Regional Tariff Level (NTR) capped at 10 as from 1st April 2017 with the view particularly of maintaining the competitiveness of the sites the furthest away from the regional network and of preventing the risk of disconnection from the gas transmission network.

A tariff framework strengthening the GRTgaz and TIGF performance incentives

The general principles of the regulatory framework applicable to GRTgaz and TIGF are retained. The regulatory framework provides stakeholders with visibility over the changes to the ATRT6 tariff between 2017 and 2020. It encourages the TSOs to improve their efficiency, both regarding cost control and the quality of service offered to network users. It also protects the TSOs against risks relating in particular to the discrepancy between forecast inflation and actual inflation.

The GRTgaz and TIGF performance incentives are strengthened through:

- the introduction of an incentive relating to "non-network" investment costs;
- simplification of the incentive mechanism relating to the quality of service given and reinforcement of its incentive nature.

An incentive scheme for the creation of more selective interconnection capacities

Over the past decade, GRTgaz and TIGF have significantly developed their networks, creating new interconnection capacities with neighbouring countries, increasing entry capacities from the LNG terminals and reinforcing the national network in order to reduce the number of marketplaces. These improvements have allowed consumers to benefit from a more diverse range of sources and have reinforced France's integration within the European gas market. However, these investments have led to transport tariff increases whilst the demand for gas in France has reduced since 2005 and forecasts have taken a downward trend.

Consequently, for new interconnection projects, the 3% bonus that had been applied since the ATRT3 tariff, has been replaced by a bonus whose amount and attribution will depend on the results of a costs/profits analysis conducted by CRE for each project.

Preparing the creation of a single marketplace in France by 2018 in line with the Tariffs Network Code

The ATRT6 tariff introduces sizeable structure developments that aim mainly to prepare the creation of a single marketplace in France by 1st November 2018. These developments, that are in line with the principles of the Tariffs Network Code[5], consist in particular of:

- rebalancing between the outlay and revenue pertaining to the main network and regional network individually, averaging out over the ATRT6 period, with the result being a 10.5% reduction on 1st April 2017 in the tariff charges for French entry points (pipelines and LNG terminals) and the exit points from the main network to the regional network;
- removal of the tariff charge for the North-South link on 1st November 2018, with transfer to the exit charge at the Pirineos Network Interconnection Point (PIR) of a portion of the revenue that was received by GRTgaz from the North-South link in order to maintain constant transit costs; and the introduction of an inter-operator compensation mechanism ;
- alignment on 1st November 2018 in € per km of the tariffs charged for the use of the two main transit routes from the north of France to Spain and from the north of France to Italy via Switzerland;

[3] Law No. 2015-992 of 17th August 2015 concerning energy transition for green growth
[4] Decree No. 2016-1442 of 27th October 2016 concerning the multi-year energy programme
[5] As adopted during committee proceedings on 29th and 30th September 2016

- over the following years, changes in line with inflation of the tariff charges at French entry and exit points, helping to provide the required visibility for the stakeholders;
- levelling of tariff charges at GRTgaz and TIGF transport storage interface points (PITS) (except for the North and South Atlantic PITS where the capacity is partially interruptible).

CHANGES TO THE TARIFF LEVEL

An initial tariff reduction on 1st April 2017, then a rise to take account of investments required to create the single market zone in 2018

At the end of March 2016, GRTgaz and TIGF sent their respective tariff files to CRE, in which they laid out their forecast costs for the 2017-2020 period. These tariff scheme files were updated at the end of May 2016 by TIGF and the end of June 2016 by GRTgaz. These applications led to the following tariff changes:

- for GRTgaz, an increase of 7.5% on 1st April 2017 (+6.3% after reprocessing the 3R transfer of costs[6], decided in CRE's deliberation of 10th march 2016 forming a decision on the equalised tariff for the use of GRDF's public natural gas distribution networks) and an average annual increase of 5.5% over the ATRT6 period (+5.1% after reprocessing the 3R transfer of costs);
- for TIGF, an increase of 8.5% on 1st April 2017 (+6.4% after reprocessing the transfer of station and connection maintenance expenses) and an average annual increase of 5.8% (+5.1% per year excluding maintenance costs) over the ATRT6 period.

CRE has made the following main adjustments:

- a weighted average capital cost set at a real 5.25% before tax (i.e. 125 basis points below the initial TSO application);
- revisions to the assumptions used concerning the operating costs of certain items, particularly energy and IT systems (i.e. an annual average of €43.9 M for GRTgaz and €5.7 M annual average for TIGF);
- additional efficiency objectives established for both TSOs on their operating cost trajectory.

The average change to the transmission unit tariff will be as follows:

- for GRTgaz, a reduction of -3.1% in 2017 (-4.3% after reprocessing the 3R transfer of costs), excluding changes in tariff structure and inter-operator compensation mechanism. Over the ATRT6 period, the tariff decreases on average by -0.4% per year (-0.8% per year excluding 3R expenses);
- for TIGF, a reduction of -2.2 % in 2017 (-4.3% after reprocessing the transfer of costs for maintenance of stations and connections), excluding changes in tariff structure and inter-operator compensation mechanism. Over the ATRT6 period, the tariff increases on average by +0.8 % per year (+0.1 % per year excluding maintenance costs).

The effect of these changes on the bill for the end consumers connected to the distribution networks and using gas heating, remains moderate in the sense that the transport tariffs represent approximately 8% of the overall gas bill for a domestic consumer using gas heating.

These changes are the result of various factors:

- increases:
  - the commissioning of significant investment projects, particularly when concerned with the creation of the single marketplace;
  - the increase in GRTgaz and TIGF operating expenses, resulting on the one hand from the changes to the traditional operator costs and, on the other hand, from the GRTgaz project, "GRTgaz 2020" and the TIGF project, "research and innovation", which aim to prepare the future of natural gas transmission networks and support energy transition;
  - the diminishing subscriptions for capacity expected for the ATRT6 tariff period;
- reduction:
  - the reduction in energy prices;
  - the reduction in the weighted average capital cost from 6.5% to 5.25%;
  - the efficiency objectives established for both TSOs.

[6] "3R costs" = income linked to the renewal, renovation and repair of delivery stations and public distribution connection facilities.

The French Higher Energy Council, consulted by CRE on its draft decision, gave a favourable opinion on 9th December 2016.

Some members of the Higher Energy Council however considered that the level of operating expenses of the TSOs that CRE has retained is insufficient, recalled the fact that the TSOs have a social responsibility, and highlighted that an excessive search for improvements in productivity could affect the working conditions of TSOs' employees, the rate of employment and the quality of the service provided to the users.

CRE underlines that the national and European legal frameworks provide for the tariffs to cover all the costs borne by the operators insofar as these costs correspond to those of an efficient network operator.

CRE commissioned an external study and carried out its own analyses of the operating expenses trajectories for the period 2017-2020 that GRTgaz and TIGF asked for to be covered by the tariff. The trajectories of operating expenses retained by CRE at the end of its analyses include an additional efficiency objective equivalent to 0.5% per year for the total covered net costs, excluding energy, between 2015 and 2017, and equal to 1% per year from 2018 onwards for GRTgaz, and equal to 1% per year for the total covered net costs, excluding energy, from 2018 onwards for TIGF.

The trajectories retained by CRE, including these additional efficiency objectives, correspond to an annual net growth rate in GRTgaz's net operating expenses (excluding energy) of 7.6% between 2015 and 2017 and of 13.4% between 2015 and 2020, and to an annual net growth rate in TIGF's net operating expenses (excluding energy) of 5.4% between 2015 and 2017 and of 12.1% between 2015 and 2020. Based on the assessment of all the information available, CRE considers that the growth in operating expenses it retains will provide the TSOs with all the resources needed to fulfil their public service missions and respond to the challenges of energy transition.

Accordingly, CRE does not modify its decision with respect to the draft decision of 17th November 2016 it submitted to the Higher Energy Council.

CONTENTS

1. METHODOLOGY

1.1 TARIFF FORMULATION PROCESS

1.1.1 Consultation with stakeholders

Bearing in mind the need for visibility expressed by the stakeholders, the complexity of the issues to be dealt with and the deadlines necessary for adapting the TSO and shipper IT systems, CRE began work on tariffs back at the start of 2016.

It was keen to involve the stakeholders as broadly and as early as possible. Consequently, CRE has held two public consultations:

- an initial public consultation in February 2016 presenting the preliminary CRE analyses on the tariff structure, the framework for the tariff regulation and the schedule of changes to the tariffs, particularly with respect to the creation of the single marketplace by 2018[7]. 38 contributors responded to this consultation, including in particular 14 shippers and shipper associations, 11 industrial consumers, 8 infrastructure operators and 3 trade unions;
- a second public consultation in July 2016 concerning CRE detailed proposals regarding structure, regulatory framework and ATRT6 tariff schedule, as well as presenting the first CRE analyses of the tariff level[8]. 57 contributors responded to this consultation: 20 shippers and shipper associations, 7 industrial consumers, 9 infrastructure operators, 17 companies or company associations mostly operating in the research sector, one joint local authority committee and 3 trade unions;

After the first public consultation, CRE held a hearing with the TSOs. After the second public consultation, CRE organised a round table with the shippers and consumers who had responded to the consultation. It also held hearings with GRTgaz and TIGF as well as their shareholders.

1.1.2 Energy policy orientations

In application of the provisions of article L.452-3 of the energy code, CRE has taken account of the energy policy orientations issued by correspondence of 28th July 2016 from the Minister of the Environment, Energy and Seas, responsible for international relations on climate. These relate to:

- consideration of the development of new gas uses in favour of energy transition (biomethane, vehicle natural gas, power to gas);
- the selection potential of future investments;
- the end of L-gas supplies from the Groningen gas field;
- the situation concerning gas-intensive consumers;
- the necessary reform of the regional tariff levels and the provisions of the Tariff Network Code with regard to transparency and non-discrimination;
- the monthly modulation of the transmission network access tariff to encourage consumers to limit their consumption during winter months.

These lines of development may be consulted on CRE's website.[9]

1.1.3 Transparency

For the purposes of transparency, CRE has published all the external reports carried out as part of the ATRT6 tariff formulation. These reports focus on the following topics:

- the international comparison of the incentive regulation mechanisms applied by electricity and natural gas system operators in Europe[10];
- an audit of the GRTgaz and TIGF operating costs for the period 2013-2020[11];
- a report on the assessment of financial calculation parameters for capital expenses[12].

1.2 General principles

[7] CRE public consultation on 25th February 2016 concerning the new access tariffs for the gas transmission networks of GRTgaz and TIGF and the new access tariffs for regulated LNG terminals
[8] CRE public consultation on 27th July 2016 concerning the new access tariffs for the GRTgaz and TIGF gas transmission networks
[9] Communication from the Minister of the Environment, Energy and the Seas on the energy policy orientations
[10] Critical analysis of the incentive regulation mechanisms for natural gas and electricity infrastructure and network operators. Schwartz and Co. final report of 23rd November 2015
[11] Pöyry report on the GRTgaz and TIGF operating costs for the period 2013-2020
[12] FTI – Compass Lexecon report on the financial calculation parameters for capital expenditure

The formulation of the ATRT6 tariff is based on the definition, for the forthcoming tariff period, of allowed revenue for each of the TSOs (GRTgaz and TIGF) and on forecast capacity subscription contracts for their respective networks.

GRTgaz and TIGF collect allowed revenue from the users of each of the networks through various tariff charges, all of which constitute the "tariff structure".

The ATRT6 tariff also establishes a regulatory framework that aims, on the one hand, to limit the TSO and/or user financial risk for certain pre-defined charge or revenue items through a revenues and expenses clawback account (CRCP) and, on the other hand to encourage the TSOs to improve their performance through incentive mechanisms.

Inclusion of all these elements enables the appropriate tariff to be applied on 1st April 2017 as well as establishing its annual tariff update procedure for the period 2018-2020.

1.2.1 Definition of forecast allowed revenue

CRE defines the forecast allowed revenue for each TSO for the 2017-2020 period based on the tariff file submitted by the operators.

This forecast allowed revenue consists of net operating expenses, normative capital charges, clearance of the balance of the revenues and expenses clawback account (CRCP) and the inter-operator financial compensation mechanism between GRTgaz and TIGF:

$$RA = NOE + NCC + CRCP + INT$$

Where:

- *RA*: allowed revenue for the period;
- *NOE*: forecast net operating expenses for the period;
- *NCC*: forecast normative capital charges for the period;
- *CRCP*: clearance of the balance of revenues and expenses clawback account;
- *INT*: inter-operator financial compensation mechanism.

1.2.1.1 Net operating expenses

The net operating expenses (NOE) are defined as the gross operating costs from which is deducted the operating income (especially capitalised production and extra-tariff income).

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

The net operating expense level used is determined from all the required costs involved in the TSO activity insofar as, in application of article L. 452-1 of the energy code, these costs correspond with those of an efficient network operator.

All the forecast data from the business plans submitted by GRTgaz and TIGF have undergone detailed analysis and, if required, revisions presented in part 2 of this resolution. In particular, CRE endeavours to use an operating expenses' trajectory that integrates productivity efforts.

1.2.1.2 Normative capital charges

1.2.1.2.1 Calculation methodology for normative capital charges

The normative capital charges (NCC) consists of the return on and depreciation of fixed capital. These two components are calculated from the valuation and development of assets operated by GRTgaz and TIGF - the regulated asset base (RAB) - and of fixed assets under construction (AuC), i.e. investments made that have not yet led to the commissioning of assets.

The NCC equates to the sum of the depreciation of assets from the RAB and the return from the fixed capital. This corresponds to the product of the value of the RAB and the weighted average capital cost (WACC) plus the product of the value of the AuC and the cost of debt.

NCC = Depreciation of the RAB + RAB x WACC + AuC x cost of debt

1.2.1.2.2 Calculation methodology for the rate of return on capital

The method adopted to evaluate the rate of return on assets is based on the WACC with a normative financial structure. The TSO's return must in fact enable it to service its debt interest and provide it with a return on equity that is comparable to that which it could obtain for investments with similar risk levels. This cost of equity is estimated based on the capital asset pricing model (CAPM).

Moreover, CRE has commissioned an external service-provider to carry out a study on the financial parameters for calculating the capital charges of gas infrastructure operators and a critical analysis of the requests from GRTgaz and TIGF concerning the calculation of the capital charges. The non-confidential version of this study was published on CRE’s website as part of the July 2016 public consultation and of this resolution.

1.2.1.2.3 Calculation methodology for the regulated asset base (RAB)

For the ATRT6 tariff period, CRE is using the same methodology for calculating the RAB as for the ATRT5 tariff. The value of the RAB is established using a "current economic costs" method, the main principles of which were fixed by the special Commission set up under article 81 of the amending Finance law of 28th December 2001, tasked with setting the price of transfer by the State of its natural gas transmission networks.

Since 2006, the conventional date for the entry of assets into the RAB has been set to 1st January of the year following their commissioning (instead of 1st July of the year of their commissioning for assets put in use earlier). The gross value of assets is adjusted for the revaluation permitted in 1976 and for subsidies received in respect of carrying out these investments.

Once integrated into the RAB, the assets are re-valued on 1st January each year using the rate of inflation from July to July. Up until 2015, the revaluation index used was the consumer price index 641194 excluding tobacco, as calculated by the French national statistics office, INSEE, for all households in France. Since 2016, following the halt in publication by INSEE of this index, the revaluation index used is the consumer price index 1763852 excluding tobacco for all households in France.

The assets are depreciated using the straight-line method on the basis of their economic lifespan. Land is accounted for using its non-depreciated re-valued historic value. The lifespans used for the main asset categories are the following :

Asset category	Normative lifespan
Pipelines and connections	50 years
Delivery, pressure-reducing and metering stations	30 years
Compression	30 years
Other appended installations	10 years
Buildings	30 years

Assets scrapped before the end of their economic lifespan are removed from the RAB and no longer produce any depreciation or financial return.

1.2.1.2.4 Return on assets prior to their commissioning

CRE renews the principle of remunerating fixed assets under construction (AuC) at the nominal cost of debt before tax, in line with the methodology generally used for interests during construction.

The amount of these AuC is equal to the average, for each year the tariff is applied, between their level estimated on 1st January and that at 31st December, taking into account the investment expenses incurred and the amount of assets commissioned during the year.

1.2.1.2.5 Treatment of stranded costs

In order to facilitate decision-making for new investments by reducing the long-term financial risk for investors, the costs to be covered by the tariff include coverage of stranded costs.

By "stranded costs", CRE means the residual book value of assets withdrawn from the inventory before the end of their lifespan, as well as expenditures relating to technical studies and upstream procedures that could not be capitalised if the projects concerned were not implemented.

These costs are accounted for on a case-by-case basis according to the files argued and presented by the TSOs to the CRE. Any revenue relating to the transfer of assets is deducted, if applicable, from the net book value covered by the capital charges. Moreover, CRE uses the framework in force for the ATRT5 tariff, in which:

- only the costs of studies previously approved by CRE and which would be abandoned during the tariff period after approval by CRE may be taken into account;
- only the stranded costs relating to compressor stations and large-scale structures removed from the inventory before the end of their lifespan may be taken into account.

1.2.1.3 Revenues and expenses clawback account

The ATRT6 tariff is defined based on assumptions concerning the level of charges and subscription revenue. A mechanism for subsequent equalisation, the revenues and expenses clawback account, was introduced to take account of variances between the actual charges and income figures recorded and the charges and income figures forecast for certain rather unpredictable items that the TSOs had difficulty controlling. The principles of this mechanism are described in paragraph 1.3.4.

1.2.1.4 Inter-operator financial compensation mechanism

To maintain coverage of the costs borne by each of the two TSOs after creating the single marketplace, which involves the removal of the tariff charge on the North-South link, CRE is introducing a financial compensation from TIGF to GRTgaz into the ATRT6 tariff for a share of the revenue received at the Pirineos network Interconnection exit point.

This development is described in detail in paragraph 1.4.5.

1.2.2 Tariff regulation framework

The GRTgaz and TIGF activity is supported by various mechanisms that form the tariff regulation framework.

Firstly, the tariff regulation framework helps to adapt the forecast allowed revenue so as to guard the operators against the risks linked with the inflation variations on their charges.

Secondly, it helps the subsequent correction of the allowed revenue, taking into account, through use of the revenues and expenses clawback account, the difference between the forecast charges or revenues and the actual charges or revenues.

Finally, in order to encourage GRTgaz and TIGF to manage their respective networks efficiently, the ATRT6 tariff includes incentive mechanisms described in paragraph 1.3.

Updating period and schedule

The ATRT6 tariff will come into force on 1st April 2017. It will apply for a period of approximately 4 years. It will be revised annually on 1st April in accordance with the rules described below.

Subject to the commissioning of the infrastructures concerned, a specific tariff movement will come into play on 1st November 2018 to deal specifically with the creation of the single marketplace. This major event that will occur during the tariff period will be reflected in:

- the entry on 1st January 2019 into the TSO RAB of assets of the Val de Saône and Gascogne-Midi projects required for the creation of the single marketplace;
- the disappearance of tariff charges at the North-South link and of revenue from market coupling, which will mean a loss of revenue for GRTgaz. This loss of revenue will be recovered through other tariff charges.

Most of the contributors to the public consultation of July 2016 stated their approval of CRE's proposal for a single tariff change at the time the single marketplace is created, to take account of the effects of the removal of the North-South link.

However, some participants have asked for this tariff change to take place on 1st April 2018 as part of the usual tariff review schedule. Several participants have even expressed the wish for the North-South tariff charges to be reduced as from 1st April 2017 so as to make the change to the single area more gradual. Finally, one participant would like the disappearance of the tariff charges on the North-South link to take place during the annual review on 1st April 2019.

CRE is not in favour of an early removal of the tariff charges on the North-South link. This option would lead to a windfall effect on those holding North-South capacities, whilst all those involved in the capacity auction were aware of the deadline of 1st November 2018. It would make it necessary to carry over the revenue shortfall to other tariff charges. Conversely, removing the tariff charge from the North-South link on 1st April 2019 would cause the creation of the single area to be pushed back to this date, which CRE is opposed to.

Consequently, the ATRT6 tariff provides for a change linked to the creation of the single marketplace on 1st November 2018 subject to the required infrastructure being in operation by this date.

The Pirineos Network Interconnection Point will change at the same time as the tariff charge on the North-South link is removed on the 1st November 2018.

In order to ensure maximum visibility for the interested parties, the level of the tariff charges on 1st November 2018 will be set by CRE in the resolution on the annual ATRT6 tariff review on 1st April 2018, expected at the end of 2017.

Elements revised during the annual tariff updating

After coming into force, the ATRT6 tariff will change on 1st April of every year, starting on 1st April 2018 and in accordance with the following principles:

a) The annual allowed revenue is determined by taking into account:

- the trajectory of the normative capital charges set for a period of four years by CRE under this resolution;
- the trajectory of net operating expenses indexed on the CPI[13] and set for a period of four years by CRE under this resolution;
- update of the "energy and CO_2 quotas" item;
- clearance of a quarter of the balance of the revenues and expenses clawback account on 31st December of the previous year;
- the forecast inter-operator compensation mechanism level.

If any charges relating to the flexibility of the L gas system increase over the tariff period - in application of agreements made between GRTgaz and Engie that CRE has already approved - these additional charges shall be taken into consideration in the annual tariff change following this increase.

b) the capacity subscriptions' assumptions are updated;

c) the tariff charges change on 1st April of every year in order for the subscription revenue to cover the TSO allowed annual revenue. The respective forecast adjustment procedures for each tariff charge are described below in paragraph 1.4.2.7.

d) Furthermore, during the annual adjustments to the ATRT6 tariff, CRE may take into consideration changes to the tariff structure, linked in particular to:

- the implementation of European network codes;
- the creation of the single marketplace in France;
- the consequences, if applicable, of the changes to the legislative and/or regulatory framework, particularly with regard to the regulation covering the operators of underground natural gas storage facilities, special processing of gas-intensive consumers and consideration of the interruptibility of certain consumers;
- significant modifications to the TSO offer (creation of a Virtual Interconnection Point with Belgium, creation of an entry point at Oltingue, etc.).

Finally, in the case where, based on mechanisms that have been put through a market consultation and been approved by CRE, the TSOs would have to sign contracts with consideration clauses to ensure the decumulation of residual congestion following the creation of the single marketplace, the corresponding expenditure and revenue will be taken into account during the annual tariff adjustment.

1.2.3 Tariff structure

The transmission network is attached to two marketplaces (the PEG[14] North and the Trading Region South, or TRS). On 1st November 2018, the two marketplaces will combine to create a single marketplace. Furthermore, in the north of France there is a "L zone" supplied with gas of low calorific value (known as "L gas").

[13] CPI is the actual annual average change recorded over the previous calendar year in the consumer price index excluding tobacco as calculated by INSEE for all households in the whole of France.
[14] Gas transfer point

The tariff structure is broken down into various tariff charges that are distributed over the transmission networks between the main network and the regional network. All these charges are paid 100% at capacity. CRE's proposal to maintain this 100% capacity tariff scheme has received a favourable response from all the contributors to the public consultation of July 2016.

The GRTgaz and TIGF network users have a number of reasons for using the gas transmission network: transit, which consists in bringing the gas in across these networks (through an entry point) and then transporting it to another country (via an interconnection exit point); and domestic transmission, which consists in transporting the gas that is to be consumed within the country. The users may also make use of French marketplaces or natural gas underground storage.

CRE sets the gas transmission tariffs so as to avoid any cross subsidy between the various transmission network uses, particularly between transit and domestic transmission. It also checks for the absence of cross subsidy between the network categories, ensuring that the charges allocated to the main network and the regional network correspond to the revenue generated by each.

1.2.3.1 Tariff system on the main network

The main network consists of network elements that connect the interconnection points with (i) adjacent transmission systems, (ii) exits to the regional network, (iii) LNG terminals and (iv) storage facilities. It extends over more than 9,500 km. The flows are generally in both directions.

The tariff structure for the main network is based on a principle of entry-exit pricing per marketplace. The gas may be purchased and/or sold directly on the marketplaces or Gas Transfer Points (PEG); in this latter case, the user pays the tariff charges that are specific to the PEG.

The users may bring the gas into France using pipeline interconnections (Network Interconnection Point, or PIR) or LNG terminals (LNG terminal transport interface point, or PITTM) and for this, they pay the charges for entry at these points.

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

- to take the gas to an adjacent country, particularly for transit uses, the shippers pay a PIR exit charge;
- for domestic use, the users pay a regional network exit charge.

Until the single marketplace is created, capacity has to be reserved for the North-South link for the transmission of gas between the gas transfer point (PEG) North and the TRS.

The underground natural gas storage facilities are situated on the main network. The network users make use of them, paying the Transport Storage Interface Point (PITS) entry and exit charges.

1.2.3.2 Tariff system on the regional network

The regional network consists of network elements that help to carry the gas from the main network to the end customers or to the distribution network. It extends over around 28,000 km. The flows are in a single direction.

The supply at each delivery point requires both a transmission capacity subscription and delivery capacity. There are 4 types of delivery points:

- the transport distribution interface point (PITD), which represents the interface between the transmission network and one or more exits to the distribution network;
- the industrial consumers who are connected directly to the transmission network;
- the highly modulated industrial consumers, meaning industrial consumers whose consumption sites have a modulated daily volume greater than 0.8 GWh;
- the regional network interconnection points (PIRR), which enable delivery to foreign regional networks.

Pricing of transmission over the regional network is based on:

- the contracted transmission capacity;
- the unit tariff for transmission across the regional network multiplied by a regional tariff level (NTR) that is specific to each delivery point and helps to take account of the difference in transmission costs on the regional network between each delivery point.

The delivery pricing is based on:

- the contracted delivery capacity;
- the unit tariff for delivery (TCL), which differs depending on the type of delivery point;
- the number of delivery stations for the industrial consumers or highly modulated industrial consumers.

Some delivery points are connected directly to the main network and do not use the regional network; these do not therefore pay any transmission tariff for the regional network.

1.3 Incentive regulation framework for the ATRT6 tariff

Article L. 452-3 of the energy code stipulates that CRE decisions regarding tariffs for use of natural gas transmission networks "*may make provision for a tariff review framework covering several years together with appropriate short- or long-term incentives to encourage operators to improve their performance particularly as regards the quality of service provided, integrating the domestic gas market, ensuring reliability of supplies and seeking productivity improvements*".

The current tariff decision reiterates the general principles of the ATRT5 tariff regulatory framework, with incentives for GRTgaz and TIGF to improve their efficiency, particularly with regard to controlling costs and the quality of service offered to the users.

The mechanisms in force for the ATRT5 tariff and repeated for the ATRT6 tariff are as follows:

- a multi-year tariff designed to apply for a period of approximately four years from 1st April 2017, with changes to the tariff grids taking effect on 1st April of every year in accordance with predefined rules;
- an incentive to control the GRTgaz and TIGF operating expenses: these TSOs will retain or bear all productivity gains or losses that may be made in relation to trajectories defined in this resolution;
- an incentive to control the energy costs and CO_2 quotas. As this item depends partially on factors that can be controlled by the TSOs, it forms 80% of the prepayment and accrued income account (20% of gains or losses are retained or borne by the TSOs).

Based on feedback from the tariff in force and the external study that it has led on the incentive regulation for natural gas and electricity infrastructures in Europe, CRE is reinforcing the incentive regulation framework in relation to that applied to the ATRT5 tariff, through the following:

- introduction of an incentive concerning the effective commitment of expenditure on research and development (R&D);
- introduction of an incentive concerning the control of "non-network" capital charges;
- reinforcement of the incentive to control costs for major network development projects;
- change to the incentive scheme for the development of interconnections;
- reinforcement of incentives concerning improvement to the quality of service.

Moreover, the ATRT6 tariff provides for a review clause becoming active after two years of the tariff being applied, to examine any consequences that may arise from legislative or regulatory changes or court or quasi-judicial rulings that might have significant effects on the operators' operating expenses in the years 2019 and 2020.

This regulatory framework will give all stakeholders the required visibility over changes in the GRTgaz and TIGF tariff between 2017 and 2020. It encourages the TSOs to improve their efficiency whilst protecting them from related risks, particularly inflation and subscription changes.

A majority of the contributors to the public consultation in July 2016 expressed their agreement with CRE lines of development relating to this regulatory framework.

1.3.1 Incentive regulation for investment expenses and net operating expenses

As part of the preparation for this tariff decision, CRE analysed possible areas for improvement to the regulatory framework, so as to further encourage GRTgaz and TIGF to control their costs and fulfil their investments.

To clarify this analysis, an external consultant was appointed to produce a report on incentive regulation mechanisms for electricity and natural gas system operators in Europe. The report focused in particular on regulation of operating expenses and investment costs. This report was published as part of the preparatory work for the GRDF ATRD5[15] tariff in 2015.

1.3.1.1 Operating expenses excluding the revenues and expenses claw-back account

The GRTgaz and TIGF incentive mechanism for controlling operating expenses excluding the revenues and expenses clawback account, is the same as that used for the ATRT5 tariff.

[15] ATRD: Third-party access to the Distribution Network

Hence the GRTgaz and TIGF net operating expenses' trajectory is defined for the period 2017 - 2020 and corresponds to an efficient operator trajectory. Any productivity gains that could be made by the TSOs in addition to the trajectory set by the ATRT6 tariff (excluding items covered by the revenues and expenses clawback account) will all be retained by the TSOs, as is the case for the ATRT5 tariff. Likewise, any extra costs that may be incurred will be entirely borne by the TSOs.

1.3.1.2 Investment spending

1.3.1.2.1 Incentive for interconnection development

Article L. 452-3 of the energy code offers CRE the option of setting up *"appropriate short- or long-term incentive measures encouraging the operators to improve their performance, particularly with regard to [...] integration into the domestic gas market, the reliability of supplies [...]"*.

Over the past decade, GRTgaz and TIGF have significantly developed their networks, creating new interconnection capacities with neighbouring countries, increasing entry capacities from the LNG terminals and reinforcing the national network to eliminate congestion and reduce the number of marketplaces. These improvements have allowed consumers to benefit from a more diverse range of sources and have reinforced France's integration within the European gas market.

Moreover, the public authorities have set objectives to reduce the consumption of fossil energy in France by 30% by 2030 as part of the LTECV.

During the public consultations in February and July 2016, CRE proposed:

- not to repeat the 3% bonus for 10 years applying to a limited number of investment projects enabling the creation of new interconnection capacities or the reduction in the number of balancing zones;
- to implement an incentive mechanism for projects creating new interconnection capacities, similar to the one currently in place as part of the electricity transmission network access tariff (resolution of 17th November 2016[16]).

A very large majority of players responded in favour of the first proposal. CRE is upholding its analysis and has decided not to repeat the 3% bonus over ten years for the ATRT6 tariff. The projects that have benefited from this bonus through preceding tariffs, will retain their incentive scheme.

A majority of players agree with CRE's proposal concerning the new incentive mechanism for the development of interconnections. Some contributors point out that this mechanism should take account of the market interest in the project. Those not in favour consider that an incentive mechanism no longer appears to be justified in a context of over-capacity at the interconnections with bordering countries.

CRE considers that some interconnection projects at French borders could prove beneficial for the market or for the reliability of supplies in Europe, and has defined a new incentive mechanism along these lines. The objectives are as follows:

- to encourage the implementation of interconnection projects that are beneficial for the community;
- to encourage the TSOs to carry out their investments under the best cost conditions.

Similarly to the mechanism chosen for electricity under the HV TURPE 5, this one is based on three separate incentives:

- the financial incentive for making interconnection investments will be seen through the attribution of a fixed bonus paid in euros and whose amount will be defined by CRE prior to the TSO's decision to commit expenditure. This fixed bonus will be calculated according to the benefit for the community and estimated by CRE based on a costs/profit analysis of the project. It will be paid upon implementation of the project, constituting an incentive to make investments as quickly as possible;
- the incentive to minimise project implementation costs will take the form of a bonus or penalty, calculated according to the difference between the target cost and actual cost of the project, in compliance with the procedures defined in this resolution (c.f. paragraph 1.3.1.2.2). In the event that the actual cost should exceed the target cost, the amount of this penalty on GRTgaz and TIGF's overall return for interconnection projects will be limited to the effect that all the cumulated incentives may not lead to a return on capital committed to the project being below the WACC - 1%;
- the incentive on use of the facility will take the form of a bonus or penalty, calculated every year dating from the commissioning of the facility, whose level will depend on the actual contracted capacities in relation to the capacities initially envisaged by the TSOs and used by CRE as part of the costs/profits' study that

[16] Decision of the French Regulatory Commission of Energy of 17th November 2016 on the tariff for use of high voltage public electricity networks.

enabled the fixed bonus to be set. In the hypothetical case where the contracted capacities are lower than the capacities initially reserved, the penalty may not exceed the equivalent of the fixed bonus payment defined by CRE upstream the decision to commit expenditure. The bonus or penalty will be applied for the first ten years of operation of the infrastructure.

The parameters used to calculate the bonuses and penalties will be set through an *ad hoc* tariff decision for each project concerned. Under this arrangement and at the latest seven months prior to the decision to commit expenditure, GRTgaz and TIGF will supply CRE with the items required for evaluating the project's net profit for the community.

1.3.1.2.2 Incentive to control investment costs

Currently, the differences in TSO capital charges between the forecast and actual trajectories are covered 100% by the tariff through the revenues and expenses clawback account, which could limit the incentive for the TSOs to control their investment costs.

Moreover, the TSO operating expenses are excluded from the parameters of the revenues and expenses clawback account (c.f. paragraph 1.3.1.1) and are therefore covered by a cost control incentive. This difference in tariff processing between the operating expenses and the investment expenditure may, in theory, encourage the network operators to choose solutions involving investment expenditure rather than solutions involving operating expenses in cases where these may be substituted.

CRE upholds the general principle of listing investments in the regulated asset base based on their real costs (subject to any audits by CRE on the effectiveness of committed expenditure). However, CRE introduces an incentive for the TSOs to make effective investment costs, implementing two separate mechanisms, the one relating to certain major investment projects and the other relating to the "non-network" normative capital charges (NCC).

Investment in the gas transmission networks

This resolution introduces an incentive regulation mechanism with the purpose of encouraging the TSOs to control the costs of major projects carried out under their management.

The report on the incentive regulation of electricity and natural gas infrastructures in Europe shows that some incentive regulation mechanisms on investment costs have already been set up by several regulators in Europe. This report advises CRE to put in place an incentive regulation mechanism for the unit costs of investment in the networks.

Under the GRDF ATRD5 tariff, an incentive regulation for the unit costs of investment in the GRDF networks has been set up. A similar mechanism has been implemented for electricity distribution as part of the MV-LV TURPE 5, which will come into force on 1st August 2017[17].

In the case of gas and electricity distribution, the proposed modelling enables the total value of a significant number of fixed assets to be estimated reasonable accurately. In fact, although the model used does not enable all the factors influencing the cost of a facility to be accounted for, the large number of projects implemented in the area of distribution helps to offset the individual errors.

In the case of gas transmission, GRTgaz and TIGF consider that the technical characteristics of their facilities (technical constraints of ground and underground occupation, geographic constraints on the land crossed, etc.) are such that their implementation costs vary considerably. Furthermore, the low number of projects implemented every year by the TSOs does not help to offset individual forecasting errors. Neither GRTgaz nor TIGF have proposed to CRE technical elements that would enable implementation of a regulation based on unit costs.

Consequently and bearing in mind the complexity of the subject, CRE is not in a position to implement a unit cost incentive regulation for the ATRT6 tariff. It is asking the TSOs to set up in-depth monitoring of the unit costs of their investments so as to be able to send CRE detailed data on the unit costs with a view to preparing the next tariff.

Cost control incentive for budget investments greater than €20 M

Nonetheless, CRE would like to reinforce the TSO incentive with regard to the control of investment costs. The ATRT5 tariff included the implementation of an incentive for any project other than safety, whose budget exceeded €50 M or represented at least 20% of the average annual sum of investments for the ATRT5 period. In the absence of any such project, this mechanism was not used during the preceding tariff period.

In its public consultation of July 2016, CRE proposed a modification to the parameters of the mechanism for the ATRT6 period, so that it could be applied to all projects whose budget is greater than €15 M.

[17] Decision of the French Regulatory Commission of Energy of 17th November 2016 on the tariff for use of HVA or LV voltage range public electricity networks.

Almost all the contributors are in favour of the mechanism proposed by CRE, but not of its application to projects already agreed upon. The TSOs consider that a fixed threshold of €15 M could apply to too many projects and that the cost of the audits risks being too great in relation to the expected profits.

CRE shares these analyses and retains a threshold of €20 M or 20% of the average annual sum of investments for the ATRT6 period for projects for which the investment decision would be made once CRE's resolution approving the investment programme for 2017 has been taken:

- CRE will audit the budget put forward by the TSO and will set a target budget, taking account if applicable of the price index of steel (HRC - hot rolled coil - index);
- whatever the investment spending made by the TSO, the asset will enter the RAB at its actual value when commissioned (less any subsidies);
- if the investment spending by the TSO on this project is between 90% and 110% of the target budget, no bonus or penalty will be attributed;
- if the investment spending is below 90% of the target budget, the TSO will receive a bonus equal to 20% of the difference between 90% of the target budget and the actual investment spending;
- if the investment spending is over 110% of the target budget, the TSO will be charged a penalty equal to 20% of the difference between the actual investment spending and 110% of the target budget.

At this stage, for GRTgaz projects that could be concerned, the budget for the ATRT6 tariff period is estimated at around €600 M (six projects excluding interconnection development projects). For TIGF projects that could be concerned the budget is estimated at €50 M (two projects excluding interconnection development projects).

The projects for which an incentive regulation has already been defined, will retain the original mechanism.

For GRTgaz, the projects concerned by this mechanism include:

- the H/B conversion project (Tulipe);
- the Southern Brittany reinforcement;
- the waterways development projects known as "Magéo" and "Canal Seine Nord";
- the reconstruction of the Vindecy compressor station;
- the reconstruction of the Bégude compressor station.

For TIGF, the two projects concerned by this mechanism are the reinforcement of the AGU compressor station and a network safety and maintenance project (Capens-Pamiers).

These lists are not exhaustive and may be added to with new projects appearing during the period covered by the ATRT6 tariff. Moreover, given that the expenditure relating to the pilot for the Tulipe project and the AGU compressor station reinforcement project will be effectively committed during the period covered by the ATRT6 tariff, they will also be subject to this mechanism on the base of budgets used by the TSOs in their decision on expenditure commitment.

Furthermore, an audit will be carried out by CRE on the decision process for investment projects, the method used by GRTgaz and TIFG to calculate the forecast cost and the monitoring by the TSOs of the cost of creating their facilities.

"Non-network" investments

This resolution introduces a mechanism encouraging the TSOs to control their capital expenditure in the same way as their operating expenses for a scope of investments known as "non-network", including assets such as property, vehicles and IT systems. As by their very nature these expense items are likely to give rise to trade-offs between investments and operating expenses, the mechanism used encourages the TSOs to optimise globally all expenditure in the interest of the network users.

The mechanism employed involves determining a development trajectory for these capital expenses over the ATRT6 tariff period, and excluding them from the revenues and expenses clawback account. 100% of the gains or losses realised will thus be kept by the operators.

During the ATRT6 tariff period, the capital charges for these asset categories will be calculated using forecast values defined in this resolution. At the end of the period, the effective value of these fixed assets will be taken into account in the RAB thus enabling, for the following tariff period, gains to be shared or extra costs to be pooled with the users.

At the end of the tariff period, CRE will conduct an analysis of the trajectories of the assets commissioned in order to ensure that any gains made over the tariff period are not offset by higher outlay in subsequent tariff periods caused, for example, by some projects being delayed.

The amount of investments made under this incentive regulation is €78.4 M on average per year for GRTgaz, i.e. approximately 14% of total investments planned during the ATRT6 tariff period; and €16.0 M on average per year for TIGF, i.e. approximately 15% of total investments planned during the ATRT6 tariff period.

Most of the stakeholders who expressed their opinion on this issue during the public consultation of July 2016, were in favour of the mechanism proposed by the CRE.

1.3.2 Incentive regulation for quality of service

The service quality indicators and associated financial incentives are detailed in Appendix 2.

1.3.2.1 Recap of the mechanism in force

The aim of the incentive regulation for the TSO quality of service is to improve the quality of service provided to transmission network users in fields considered particularly important for good operation of the gas market.

Since 1st April 2016, the TSO service quality has been monitored using 23 indicators. Of these 23 indicators, 6 are subject to a financial incentive in order to improve the quality and provision of data for the shippers.

The 23 indicators monitored relate to the following topics:

- the quality and availability of data to shippers from the TSOs (6 indicators);
- the information published and the types of TSO intervention on the markets as part of the balancing system put in place on 1st October 2015 (4 indicators);
- compliance with the forecasts provided to the shippers concerning the TSO schedule of works (6 indicators);
- the quality of relations held between the TSOs and the shippers and distribution network operators (4 indicators);
- the availability of the North-South link (1 indicator);
- the environmental impact of the TSOs (2 indicators).

In order to take account of the progress made by the TSOs, to simplify the current mechanism and to strengthen its incentive nature, this tariff decision helps to develop the incentive regulation concerning quality of service.

1.3.2.2 Simplification of the service quality monitoring mechanism

In order to focus the service quality monitoring mechanism on the indicators that are of most value to the shippers, CRE proposed the removal of 9 indicators in its two public consultations. The majority of responses at these public consultations were in favour of these deletions, which would contribute to increasing the clarity of the mechanism for the network users.

Several shippers wish to maintain monitoring of the two indicators relating to the North-South link. CRE shares their analysis and considers that, even if the North-South link is planned to go in 2018, the indicators relating to this link are still very important from now until then. Hence, the following two indicators that were meant to be removed, are being continued:

- availability to the market of additional firm capacities on the North-South link;
- compliance with the maintenance programme relating to interruptible capacity on the North-South link published in M-2 by GRTgaz.

Several players would like to keep the indicator relating to the availability of user portals. This indicator will continue being monitored without there being any direct financial incentive. Nevertheless, in the event of portals being unavailable, financial penalties will be applied, as the indicators with financial incentives (c.f. paragraph 1.3.2.3) and relating to the availability of the 5 pieces of information of most use for balancing and concerning the quality of overall consumption forecasts, will suffer the consequences.

The 6 indicators below will no longer be monitored as part of the service quality incentive regulation mechanism:

1. monitoring of connection completion deadlines, i.e. the number of days actually needed to power up new connection facilities in relation to the deadline stated in the contract with the customer. The low number of new connections observed over the past five years (fewer than 3 per year in France) has made this indicator irrelevant;

2. the reliability of information on the customer portals, based on the number of complaints regarding the reliability of information. Indeed, the TSOs are in direct contact with their customers, who rarely make use of the complaints' channel on this subject;
3. the deadlines for sending files to the distribution system operators (DSOs) relating to withdrawals from the PITDs, i.e. the number of days per month when the TSO has sent to the DSOs the file of daily forecast withdrawals from the PITD beyond the deadline: the quality of data from the PITDs is already covered by incentives and late submissions are monitored under the ATRD5 tariff. This indicator is therefore redundant;
4. monitoring of TSO actions in the markets for the purpose of balancing;
5. monitoring of returns to linepack from the previous day (MWh at 25°C):

   these two indicators are aimed at ensuring that the TSOs take action to balance out, whilst controlling their intervention costs. CRE considers that the price at which the TSO purchases or sells gas for balancing is not related to the quality of service provided to the shippers. As such, these indicators will be monitored and presented in Concertation Gaz in the context of monitoring balancing and not the quality of service;
6. the average time taken to process capacity reservation requests: these days, these requests are entirely automated through the PRISMA, TRANS@ctions and DATAGAS platforms under the conditions defined by the CAM Network Code[18].

Moreover, in the ATRT5 tariff, the quality of intraday quantities remotely metered at the delivery points of consumers connected to the transmission network and sent during the day, is monitored using two different indicators:

- the TIGF indicator relates to the number of compliant intraday readings remotely metered at industrial delivery points[19] over the month, compared with the total number of intraday readings remotely metered at industrial delivery points over the month (a value monitored in timeslots);
- the GRTgaz indicator monitors the very good quality, good quality and poor quality information rates. Information is said to be of very good quality if the variation, in absolute value, between the measurement of energy for day D sent during the day and the definitive measurement for day D sent at M+1 is strictly below 1%. If the deviation is between 1% and 3% (respectively strictly higher than 3%), the value is of good quality (respective to poor quality).

In order to harmonise the methods of calculating this indicator, in the public consultation of 27th July 2016, CRE proposed that both TIGF and GRTgaz should use only one indicator definition: the very good, good and poor quality information rate based on the 1% and 3% thresholds. Responses to the consultation are in favour of this change. CRE is using this change for the ATRT6 tariff.

1.3.2.3 Financial incentive for the availability of the 5 most useful pieces of data on the TSO public portals for shippers for balancing purposes

To represent the change to data required for effective operation of the market, a new financial incentive has been introduced relating to the availability of the five most useful pieces of data for shippers for balancing purposes. These five elements are as follows:

- forecast line packs published every hour throughout the day;
- forecast imbalance published every hour throughout the day;
- the cost of adjusting the imbalances of the current day published every hour throughout the day;
- the overall consumption forecast per zone (D and D+1);
- allocations for the Pirineos interconnection point.

Penalties and bonuses are calculated from the rates of availability for the data considered.

This indicator is monitored between 6am and midnight, with the time slot between midnight and 6am made available to TSOs to carry out maintenance work on their IT systems.

The procedures for this incentive are defined in Appendix 2.

1.3.2.4 Availability of firm capacities

[18] COMMISSION REGULATION (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems
[19] For a given month M, a reading is compliant if there are no more than 5 days in month M for which the metering of energy in the timeslot for day D sent on day D is of poor quality. A reading sent on day D is of poor quality if the variation, in absolute value, with the definitive reading for the same timeslot on day D sent at M+1 is strictly greater than 3% and 100 kWh.

Whilst working on their networks, the TSOs interrupt the interruptible capacities, followed by the firm capacities if necessary.

Since 1st April 2012, the TSOs have been publishing the availability rate of firm capacities, per month on an aggregate basis for each type of point (network interconnection points (PIR), LNG terminal interface points (PITTM) and transport storage interface points (PITS)).

In the 2014 report on the TSO and DSO service quality[20], CRE had written a critical statement concerning the GRTgaz performance in this field.

At the beginning of 2016, GRTgaz launched initiatives to increase the availability of firm capacities. These relate to 4 main areas:

- optimisation of the organisation of work;
- innovation in technical aspects to reduce the time required for work to be carried out;
- improvement to the reliability of published forecasts;
- adaptation of the commercial offering to maximise the available capacity.

The GRTgaz proposals gave rise to positive reactions from the users, who would like these developments to be implemented as soon as possible. At the public consultation of July 2016, CRE felt that, in view of the actions undertaken, it was not necessary to attach financial incentives to this indicator from April 2017. The majority of responses to the consultation agree with CRE analysis.

CRE upholds its analysis and is not using any financial incentive for the provision of firm capacities. A similar incentive may be looked into again in light of the results of actions by GRTgaz.

In their monitoring, the TSOs will give details of the rate of availability of firm and contracted capacities point by point and no longer on an aggregate basis for each type of point.

1.3.2.5 Financial incentive levels

The changes mentioned above have had the effect of lowering the number of incentive indicators from six to five. As such, one new indicator is incentive-based, one is maintained although its incentive nature has been removed and two incentive-based indicators have been combined. Thus the following five indicators will be attached to financial incentives under the ATRT tariff:

- quality of quantities measured at the PITDs and sent to the DSOs the next day for calculation of provisional allocations;
- quality of daily quantities remotely metered at points of delivery to consumers connected to the transmission network and sent the next day;
- quality of inter-day quantities remotely metered at points of delivery to consumers connected to the transmission network and sent during the day;
- quality of overall end-of-day gas consumption forecasts made the day before and during the day;
- monitoring the provision of the five items of information most useful for balancing operations on the TSO public sites.

The incentive levels are harmonised between the indicators. Thus, for each indicator, the incentive cap is set at +/- €600 k for GRTgaz and +/- €300 k for TIGF. Similarly, the parameters for calculating the financial incentives are harmonised between GRTgaz and TIGF:

- the parameters relating to indicators that are proportional to the number of balancing zones are identical between GRTgaz and TIGF;
- the parameters relating to indicators that are independent of the number of balancing zones are twice as high for GRTgaz as they are for TIGF.

When creating a single marketplace, in order to maintain an identical incentive, the parameters relating to indicators that are proportional to the number of balancing zones for GRTgaz will be reviewed.

1.3.3 Incentive regulation mechanism for research and development (R&D) expenditure

[20] Incentive regulation regarding the service quality of electricity and gas network operators - 2014 report published on 9th February 2015

The regulatory framework defined for the ATRT5 tariff did not include any particular incentive in the field of R&D. The TSO was therefore encouraged to control its R&D expenditure in the same way as it did for its other operating expenses.

Similarly to the DSOs, the TSOs are faced with stagnation, or even a drop in gas consumption. It would appear necessary to study new possible uses of gas transmission networks and support energy transition.

In its public consultation in February 2016, CRE proposed the implementation of an incentive for the TSOs to commit research and development expenditure effectively. Almost all the players were in favour of this proposal.

For the ATRT6 tariff period, CRE is setting up an incentive regulation for R&D expenditure that is similar to that of the ATRD5 tariff and the TURPE. Any budget allocated to R&D and which have not been used will be restored to users at the end of the tariff period through the revenues and expenses clawback account. In the event that the TSOs exceed the four-year trajectory, they will be responsible for the difference.

Furthermore, the TSOs will have to send an annual report of R&D projects to CRE for publication in order to report to the users on innovation projects carried out by the TSOs. This report will include the following in particular:

- a description of the projects carried out and partnerships made, together with a list of related expenses and the results obtained;
- a list of current and upcoming projects, together with the expected results;
- the amounts spent over the past year;
- expenditure forecasts for each year until the end of the tariff period;
- the number of full-time equivalents allocated to the R&D programmes;
- any support or grants received.

1.3.4 Revenues and expenses clawback account (CRCP)

The ATRT6 tariff is defined based on assumptions concerning the level of expenditure and subscription revenue. A mechanism for subsequent equalisation, the revenues and expenses clawback account (CRCP), was introduced to take account of variances between the actual expenditure and income figures recorded and the expenditure and income figures forecast for certain rather unpredictable items that the TSOs had difficulty controlling. The method for calculating the CRCP is in line with tariff balance for each calendar year.

The balance of the CRCP is calculated on 31st December of each year. It takes account of all or part of the differences in expenses or income noted for predefined items; in the case where the item is only partially covered by the CRCP, the gain or loss in relation to the forecast held by the operator constitutes a cost control incentive. The balance of this account is cleared over four years in constant payments, calculated automatically as part of the tariff changes implemented on 1st April every year with a reduction or increase in income to be recovered by the tariff. In order to ensure the financial neutrality of the mechanism, an interest rate equal to the non-risk rate taken into account in the calculation of the WACC, is applied to the balance of the CRCP.

The majority of contributors to the public consultation of July 2016 expressed their agreement for reiteration of the CRCP mechanism under the same conditions as those used for the ATRT5 tariff.

CRE has decided to retain the general principle of the existing CRCP mechanism, whilst altering the outline of the expense and income items it covers.

The items included in the outline of the CRCP for the ATRT6 tariff, unchanged from the ATRT5 tariff, are as follows:

- the capital expenditure borne by the TSOs, with 100% inclusion apart from those involved in the "non-network" capital charges incentive regulation mechanism and for which only the inflation difference is included (c.f. paragraph 1.3.1.2.2);
- the motive power expenses (gas and electricity) and CO_2 quota purchases and sales by the TSOs. To encourage the TSOs to control these expenses, 80% of the variances within this item are covered by the CRCP;
- 100% of the difference between the forecast inflation considered by CRE for the annual updating of TSO operating expenses and the actual inflation, is covered by the CRCP;
- 100% of the tariff revenue downstream from the gas transfer points (PEG) and which the TSOs cannot influence, is covered by the CRCP:
  - revenue from the exit capacity of the main network, transmission across the regional network and delivery;
  - revenue from storage facility entry and exit capacity;

    - revenue from the North-South market coupling and JTS (Joint Transport Storage);
    - proximity discount;
    - H gas to L gas peak conversion revenue;
- the expenses for GRTgaz and the revenue for TIGF relating to the agreement between GRTgaz and TIGF for the use by GRTgaz of the TIGF network. 100% of the total of these expenses and revenue is covered by the CRCP. A variation in the amount of the contract has no impact with regard to the overall transmission cost in France;
- the connection products for combined cycle gas turbines (CCGT) and combustion turbine generators (TAC) are 100% covered by the CRCP because of their unpredictability.

The new expenditure and revenue items included in the scope of the CRCP of the ATRT6 tariff or that have been changed in relation to the ATRT5 tariff, are as follows:

- the R&D operating expenses in accordance with the procedures defined in paragraph 1.3.3: at the end of the tariff period, a report on the amounts effectively spent by each TSO is made, taking account of the actual inflation. If the TSO has spent less than the forecast trajectory, the difference is returned to the users. If the TSO has spent more than the forecast trajectory, the difference is to be paid by the operator;
- 100% of the difference in expenditure for the service converting H gas to L gas resulting from changes in the converted volumes, is covered by the CRCP. In fact, the volumes converted mainly depend on the rate at which markets open in zone L;
- expenses relating to the separation of GRTgaz R&D activities from those of Engie, the costing of which is still ongoing. These are covered 100% by the CRCP, subject to approval by CRE of contracts concluded in this area between Engie and GRTgaz;
- the provisional costs of the pilot project converting zone L to H gas, upon request of GRTgaz and based on the results of the technical and economic report that will be led by CRE in compliance with article L.431-6-1 of the energy code. The forecast costs covered by the CRCP will be defined as part of a CRE resolution which will determine the corresponding benchmark amounts;
- the revenue from services for third parties relating to major land development work where completion work is unclear and upon which the TSOs have no influence (for example, rail or motorway projects), will be covered 100%;
- 80% of transmission revenue received upstream of the main network (excluding main network exits, storage facility entries and exits and market coupling and JTS mechanisms) is covered by the CRCP rather than 50% to take account of the automation of marketing procedures via the PRISMA platform, whilst continuing to encourage the TSOs to maximise subscriptions, particularly by making additional capacities available. The same applies to the following appended costs and revenue:
    - PEG (gas transfer point) access and transactions;
    - revenue from the Alizées balancing services for GRTgaz and the SET for TIGF;
    - gas injection on the transmission network;
    - UIOLI (Use it or lose it) and UBI (Use it and buy it) mechanisms;
    - auction of daily capacities;
- any costs relating, if applicable, to the remuneration by the TSOs for consumers connected to the transmission network and who may have signed an interruptibility contract based on article L.431-6-2 of the energy code;
- the CRCP covers 100% of the difference between the forecast and the compensation made between TIGF and GRTgaz for a share of the revenue received at the Pirineos interconnection exit point.

The bonuses and penalties resulting from the various incentive regulation mechanisms are paid via the CRCP.

The accounting data presented by the TSOs will be used as the base for expenditure and income accounted for via the CRCP, where possible.

1.3.5 Net operating expenses periodic review clause

This resolution reiterates the periodic review clause concerning the level of expenditure covered by the ATRT6 tariff, becoming active two years after the tariff comes into force, i.e. for the tariff change on 1st April 2019.

The periodic review clause, identical to that used for the ATRD5 GRDF tariff, TURPE 5 and which was already included in the ATRT5 tariff, stipulates that any consequences of new legislative or regulatory provisions or of a judicial or quasi-judicial decision, may be examined if the level of net operating expenses used in the ATRT6 tariff is altered by at least 1%. The net operating expenses' trajectory to be covered by the ATRT6 tariff may be amended after such an examination, with the financial consequences resulting from these changes only being taken into account for 2019 and 2020.

1.4 Changes to the structure of the tariff of the natural gas transmission networks on 1st April 2017 and changes over the period 2018-2020

1.4.1 Recap of the tariff structure formulation principles

The ATRT6 tariff structure is established so as to reflect the real costs generated by the users and avoid cross subsidies between the various user categories.

1.4.1.1 Cost-revenue balance on the main network and the regional network

The absence of cross subsidies involves the definition of a tariff structure that will enable expenditure pertaining to the main network and the regional network to be covered by revenue received from each of the networks.

The cost-revenue balance objective on the main and the regional networks has been continued by CRE over several tariff periods; in particular, re-balancing operations have been carried out on several occasions (2007 and 2009) in order to achieve this objective.

The TSOs have sent CRE their tariff file showing the distribution of expenditure between the main and regional networks[21].

1.4.1.2 Absence of cross subsidy between the transit and domestic use on the main network

The Tariffs Network Code introduces a reference method ("*Capacity Weighted Distance*") which aims to ensure the consistency of unit costs borne by the various user categories, distributing the expenditure over the different tariff charges according to contracted capacities and the distance covered by the gas.

The ATRT6 tariff is designed to avoid any cross subsidy between the users of transit routes and domestic users, particularly with regard to the distance covered by the gas on the main network.

1.4.1.3 Revenue distribution between main network entries and exits

The Tariffs Network Code describes an indicative 50/50 distribution between the revenue made at the entry to the main network and that made at the exit of the main network. The distribution made through application of the tariff may be different if this is justified.

The energy code does not actually stipulate any specific rule for distribution between the entry and exit terms.

1.4.1.4 Progressive increase of tariff changes

CRE has prepared the ATRT6 tariff, checking on the progressivity of the changes in relation to the ATRT5 tariff, insofar as:

- numerous players, particularly the users of transit routes, have taken out contracts for long-term capacities at interconnection points and entries from the LNG terminals;
- many consumers have opted for a gas supply based on a tariff structure that must be sustained in the long-term.

1.4.2 Relative tariff levels on the GRTgaz and TIGF networks

1.4.2.1 Cost and revenue balance on the main and regional networks

After several successive tariff changes, the tariffs in force at the end of the ATRT5 period led to a slight imbalance between the costs allocated to each network category and the revenue that it generated. The distribution of costs and revenue between the main network and the regional network in 2016 is as follows:

[21] The allocation of operating expenses for each network category is made based on costs actually borne by each of the networks. Certain items that may not be allocated require the application of settlement rates. CRE uses the TSO proposal of a rate per kilometre of network or 50/50 depending on the item concerned.

%	Main network	Regional network
Share of TSO costs	46%	54%
Share of TSO revenue	51%	49%

During the public consultation in July 2016, CRE proposed the progressive rebalancing of the revenue made by the main and regional networks during the ATRT6 period in order to achieve the balance between expenditure and revenue borne and made by each network category, in 2020.

Approximately half of the contributors agreed with this proposal. However, the other half felt that the rebalancing should be operated from the start of the ATRT6 tariff period so as to correct the current situation of imbalance as soon as possible. Some participants stressed that if the balance was only achieved at the end of the period, this would act to perpetuate cross subsidy between the main network and the regional network during the ATRT6 tariff period.

With regard to these elements and in order to avoid cross subsidy between the two network categories, whilst limiting the effect that total rebalancing could have from 2017, CRE is employing a progressive change to tariff charges so that the balance between revenue received and the costs pertaining to each of the main and regional networks is reached on average over the 2017-2020 period.

1.4.2.2 Revenue distribution between entries and exits

In France, the entry/exit revenue ratio was 35/65 for 2016.

In 2016, the weighted average level per capacity of entry tariffs (for network interconnection points and LNG terminal interface points) on the main network was €110/MWh/d/year, whereas the weighted average level of exit tariffs (for network interconnection points and exits to the regional network) was €120/MWh/d/year. The relative entry and exit tariff levels are therefore close to a 50%/50% balance, thereby complying with the spirit of the European Tariffs Network Code. At its public consultation, CRE proposed to maintain the current 35/65 ratio. The participants' response to this was divided: where half were in favour of the stability of the balances, others hoped to break from the entry/exit revenue distribution, moving further away from the indicative ratio of the Tariffs Network Code.

This situation is justified by the presence in France of high storage capacities that help to provide for the switch to winter peak. Hence the contracted capacities at the entry to the French transmission network are significantly lower than the exit contracted capacities that are required to provide the supply for all consumption during peak periods.

CRE will maintain the 35/65 ratio for the ATRT6 tariff period.

1.4.2.3 Consequences of removing the tariff charge from the North-South link by 2018 on the tariff structure for transit from the north of France to Spain

The shippers transiting through France mainly use the routes passing from the north of France towards Spain and Italy. The cost borne by the users of these routes is the sum of tariff charges paid by them.

In its two public consultations on the ATRT6 tariff, CRE indicated that it envisages maintaining a constant level, everything else being equal, of the total costs of the transit routes. The majority of contributors supported CRE's proposal.

The creation of the single marketplace in France at the end of 2018 will lead to the removal of the tariff charge from the North-South link (i.e. €208.04/MWh/d/year), resulting in a loss of revenue for GRTgaz. However, this change has no effect on the costs and characteristics of the service provided by the TSOs, since it concerns the transit between the north of France and Spain.

As a result, at the public consultation in July 2016, CRE proposed to maintain at a constant level the cost of the France-Spain route at the time the North-South link is removed, by transferring a share of the revenue currently received from the North-South link to the Pirineos exit point tariff.

The large majority of contributors to the public consultation were in favour of this principle, which fits in with the continuity of changes already implemented by CRE when it reduced the number of earlier marketplaces. A minority of participants were opposed to this principle. One of them was in favour of transferring the revenue shortfall relating to the removal of the North-South link to other tariff charges on the GRTgaz network.

At the time of creation of the single marketplace, the unit cost of transit towards Spain will be maintained at a constant level through an increase in the Pirineos interconnection exit point charge. However, this increase will not amount to the total of the current North-South charge to the extent that CRE will align the unit cost of the transit routes under the conditions indicated in paragraph 1.4.2.4.

1.4.2.4 Relative levels of tariff charges with regard to the distance at the time the single marketplace is created

The objective of avoiding cross subsidy between the various gas transmission network user categories requires ensuring the correlation between the level of tariff charges and the distance covered by the gas.

The Tariffs Network Code, that aims to harmonise the tariff structures in the European Union for gas transmission systems, specifies that the average unit cost borne by each user category must be identical. The distance covered by the gas is the preferred cost driver in the document.

As part of the preparation work for the ATRT6 tariff, CRE has carried out analyses to ensure that the gas transmission tariffs comply with this principle. It has calculated on the one hand, the tariffs for the various transit routes and, on the other hand, the domestic transmission tariffs, in relation to the distance covered on the main transmission network. From the modelling methods mentioned in the public consultation of July 2016, CRE is using the one that takes account of storage when determining the distances covered. In 2016, the analyses of distance covered by the gas led to a unit tariff from €0.69/MWh/d/year/km to €0.89/MWh/d/year/km inclusive for domestic transmission[22] and transit unit tariffs of €0.70/MWh/d/year/km[23] for the France-Italy route and €0.78/MWh/d/year/km[24] for the France-Spain route. As the unit costs of the domestic routes and the France-Italy transit are similar, there is no cross subsidy between these two user categories.

The model highlights a difference between the unit costs on the France-Spain and France-Italy transit routes. At the second public consultation, CRE therefore proposed to realign the unit cost of transit to Spain with that of transit to Italy. It has proposed that this alignment should take place when the North-South link charge is removed, which will mean only transferring part of the charge relating to the North-South link to the Pirineos exit tariff.

The majority of participants are in favour of the principle of aligning the transit route unit costs. However, several participants are in favour of an alignment with the average cost of the routes and not with the lowest cost, so as to avoid increasing the share of costs borne by domestic transmission without justification.

With regard to these elements, CRE will align the unit costs of the France-Spain and France-Italy transit routes based on the average unit cost of these two routes. This change will take place at the same time as the creation of the single marketplace, planned for 1st November 2018. In view of the reduction to all charges on the main network in 2017, the average unit cost of the two transit routes will be fixed at €0.68$_{2017}$/MWh/d/year/km, whereas the average domestic transmission unit cost will be between €0.62 and €0.80/Mwh/d/year/km inclusive.

1.4.2.5 Changes to the tariff structure for the main network

The changes decided by CRE for the ATRT6 tariff will lead to a drop in the TSO allowed revenue in 2017, linked mainly to the reduction in the WACC (c.f. section 2.1.3).

This reduction, combined with the rebalancing of revenue between the GRTgaz and TIGF main and regional networks, led CRE to propose at the public consultation of July 2016 a reduction in the main network (entries and exits) tariff charges on 1st April 2017 (-4% in the scenario illustrated during the public consultation). Consequently, the tariff charges at the PIR, PITTM and PITS will change with inflation, as was the case during the ATRT5 period, so as to rebalance progressively the revenue between the main network and the regional network.

The majority of participants at the public consultation responded favourably to the changes proposed by CRE. They consider that the structure proposed will help to make the French market more attractive without adding a burden of disproportionate charges to the regional network.

However, in their concern for the attractiveness and preservation of the liquidity of the French market, some shippers consider that the reduction proposed at the entry points is not big enough. They express their preference for a substantial reduction or cancellation of entry charges at the PIRs and PITTMs and a transfer of the revenue shortfall to the exit charges on the main network. Other contributors however would like a reduction to the charges borne by the French consumers who experienced big increases during the ATRT5 tariff. Some of them request an

[22] The average distance covered by the gas to supply French consumers varies, according to the hypothesis used, from 238 km (average of distances covered weighted by the number of summer months (period of injection into storage) and winter months (withdrawal period)) to 310 km (only the distance covered in winter accounted for).
[23] Dunkerque gas interconnection entry point and Oltingue interconnection exit point
[24] Dunkerque gas interconnection entry point and Pirineos interconnection exit point

increase to the entry charges in France so as to approach the indicative 50/50 ratio planned for the distribution between the main network entries and exits in the Tariffs Network Code.

As indicated in paragraph 1.4.2.2, CRE is in favour of maintaining the current revenue distribution ratio between the main network entries and exits because of the high storage capacities in France that allow lower entry capacity subscriptions than exit subscriptions.

Moreover, CRE does not agree with a reduction to entry charges that would exceed those permitted by the rebalancing between the expenditure and the revenue received from the main and regional networks. Indeed, an artificial reduction to these charges would require a transferral of exit costs to the exits towards the regional network. However, the analysis of unit transmission costs for the various network user categories shows the absence of cross subsidy between transit users and national consumers. CRE therefore deems it necessary to change the main network charges in the same way for these two user categories. These reductions would moreover be a burden on the end consumer without providing any certain benefit with regard to market attractiveness and liquidity.

As indicated in paragraph 1.4.2.1, this rebalancing will be operated as an average on the ATRT6 tariff. The result of this will be a more significant reduction in the main network charges during the first year (-10.5%). After that, entries to the main network and PIR exits will change with inflation. As from the creation of the single marketplace, the costs charged for the main network will have changed in the same way for the transit routes as for the domestic routes (-10.5% in 2017, then with inflation for the domestic routes as for the average of transit routes).

To summarise, the main network tariff charges will change as follows:

- the charges at PIRs (except for exit charges at the Oltingue and Pirineos PIRs), PITTMs and PITS, will drop by -10.5% on 1st April 2017. They will change with inflation on 1st April 2018, 2019 and 2020, in such a way as to ensure the necessary visibility for stakeholders and as required by the Tariffs Network Code;
- the tariffs for transits to Spain and Italy will be aligned on 1st November 2018 to a level of €0.68$_{2017}$/MWh/d/year/km. To prepare for this deadline, the Pirineos and Oltingue exit charges will drop by -0.5% on 1st April 2017;
- the main network exit charge will drop by -10.5% on 1st April 2017. It will then change with inflation, but at the annual reviews, any differences in expenses or subscriptions that may be seen to affect the tariff will be applied to this charge.

The North-South link charge will remain constant in current euros in both directions until the creation of the single marketplace. On this date, this charge will be removed and part of it, €117.9/MWh/d/year, will be transferred to the exit charge of the Pirineos PIR in order to align the costs of the two transit routes.

1.4.2.6 Changes to the regional network tariff structure

Because of the rebalancing of expenditure and revenue between the main network and the regional network, the tariff charges on the regional networks will increase during the ATRT6 tariff period. They will remain constant on 1st April 2017 (except for structural effects relating to reform of the regional tariff levels and to the transfer of maintenance expenses from DSOs to TSOs); then they will increase each year proportionately between the GRTgaz regional network and the TIGF regional network.

The reform of the regional tariff levels described in paragraph 1.4.3 will be reflected in an increase to the GRTgaz regional capacity charge of +3.1% and to the TIGF regional capacity charge of +4.2% on 1st April 2017. Furthermore, the delivery charge (TCL) to the PITD will increase by +15% for GRTgaz and +39% for TIGF, to take account of the transfer of maintenance expenses.

1.4.2.7 Summary of changes to the forecast tariff charges for 2017-2021

%	Tariff on 1st April 2016	1st April 2017	1st April 2018	1st Nov. 2018 (creation of the single marketplace)	1st April 2019	1st April 2020
PIR/PITTM entries		-10.5%	inflation	-	inflation	inflation
PITS entries/exits		-10.5%	inflation	-	inflation	inflation
Oltingue exit		-0.5%	inflation	-	inflation	inflation
Pirineos exit		-0.5%	inflation	23.6%	inflation	inflation
North-South link		0.0%	0.0%	-100%	0.0%	0.0%
Exits to regional network		-10.5%	inflation +/- annual changes	-	inflation +/- annual changes	inflation +/- annual changes
GRTgaz regional network		0.0%*	+4.5% +/- annual changes	-	+4.5% +/- annual changes	+4.5% +/- annual changes
TIGF regional network		0.0%*	+5.4% +/- annual changes	-	+5.4% +/- annual changes	+5.4% +/- annual changes
Pirineos PIR exit charge (€/MWh/d/year)	496.89	494.2	499.2	617.1	623.3	629.5
France-Spain transit cost (€/MWh/d/year)	819.23	804.6	810.5	720.4	727.6	734.9
France-Italy transit cost (€/MWh/d/year)	513.09	498.9	503.9	503.9	509.0	514.1
Transport PEG-customer NTR 0 (GTRgaz) (€/MWh/d/year)	129.5	119.0	121.2	121.2	123.5	125.9
Transport PEG-customer NTR 2 (GTRgaz) (€/MWh/d/year)	273.6	267.6	276.6	276.6	285.9	295.6
Transport PEG-customer NTR 8 (GTRgaz) (€/MWh/d/year)	706.0	713.4	742.5	742.5	772.9	804.6
Transport PEG-customer NTR 0 (TIGF) (€/MWh/d/year)	126.0	115.5	117.8	117.8	120.2	122.6
Transport PEG-customer NTR 2 (TIGF) (€/MWh/d/year)	263.8	259.1	269.2	269.2	279.8	290.9
Transport PEG-customer NTR 8 (TIGF) (€/MWh/d/year)	677.5	690.2	723.5	723.5	758.6	795.6
% of revenue received by main network	51%	49%	47%	-	45%	44%
% of revenue received by regional network	49%	51%	53%	-	55%	56%

* As part of the regional tariff level (NTR) reform described in paragraph 1.4.3, the GRTgaz regional capacity charge increases by +3.1% and that of the TIGF network increases by +4.2%. The PITD charge increases by +15% for GRTgaz and by +39% for TIGF to account for the transfer of "3R" expenses from the DSOs to the TSOs. The changes to the regional network on 1st April 2017 are presented excluding consideration for these effects in this

table. The PEG-customer transmission costs calculated for the different regional tariff levels do take these into account.

In addition to the changes described in this table, the GRTgaz and TIGF exit charges from the main network and the regional network charges may be reviewed depending on the expense and subscription discrepancies that could appear at each annual tariff review.

1.4.2.8 Changes to the PITS tariff structure

1.4.2.8.1 Harmonisation of tariff charges for the PITS

In its resolution of 29th January 2014 stating its decision on the changes to the ATRT5 tariff on 1st April 2014, CRE used a multiplying factor of 1.33 for tariffs at GRTgaz Sud transport storage interface points (PITS) and tariffs at TIGF PITS. The purpose of this factor, set based on conclusions from an external study, was to reflect the difference in service offered by each TSO, since the GRTgaz capacities marketed at the PITS were firm climatic capacities, whereas the TIGF capacities marketed at the PITS were firm capacities.

The creation on 1st November 2018 of a single marketplace in France will lead to direct competition between storage operators over the whole country. Moreover, the average GRTgaz and TIGF interruption rates at the PITS between November 2014 and October 2016 were comparable, with the exception of those at the North Atlantic and South Atlantic PITS. In the public consultation of July 2016, CRE proposed the harmonisation of tariff charges at the PITS, except for North Atlantic and South Atlantic, insofar as the services provided are comparable.

The majority of contributors at the public consultation expressed their agreement with this proposal. Some contributors have shown the desire to see the tariff charges at the PITS set at 0 so as to reflect the profits procured through storage on the transmission networks, particularly with regard to investment costs avoided.

CRE does not agree with cancelling the tariff charges for the PITS: these are already down by 85% on average for 2016 in relation to the tariffs at other entry and exit points. This rate of reduction, which exceeds the 50% indicative reduction rate stipulated in the Tariffs Network Code, is already helping to account for the transmission cost savings made, thanks to the existence of this storage.

The tariffs for French PITS, except for North-Atlantic and South-Atlantic, will be harmonised as from 1st April 2017. This harmonisation will be calculated based on forecast subscription assumptions for 2017 in order, on the one hand, to retain the income for the PITS at a constant level on the France link and, on the other hand, to maintain the PITS entry/PITS exit ratio at a stable level. After harmonisation, the tariff charges for the PITS will change in the same way as the other main network charges, i.e. with a 10.5% drop for the first year, followed by changes with inflation.

1.4.2.8.2 Capacity charges for the North-Atlantic and South-Atlantic PITS

The entry/exit capacities marketed by GRTgaz at the PITS are firm climatic capacities for all the PITS, except for the North-Atlantic and South-Atlantic PITS, where they also include a share of interruptible capacities.

The interruption rates of contracted capacities observed since 1st November 2014 as injections into the North-Atlantic PITS and withdrawals from the South-Atlantic PITS, amount to 30% on average.

As a result, the ATRT6 tariff sets a tariff that is lower at these points than for other PITS, reflecting the different nature of the products marketed and the interruption rates observed. As from 1st April 2017, the tariff for capacities at the North-Atlantic and South-Atlantic PITS will be 70% of the tariff of capacities at other PITS.

1.4.2.9 Changes to the PITTM offering

The ATRT5 tariff limited the subscription for income during the month to capacities at the PITTMs in multiple 10-day blocks.

In its second public consultation, CRE proposed the creation of capacity income at the PITTMs for durations of N days, N being above or equal to 10. All the participants were in favour of this change. These products have been introduced through this tariff resolution.

This change helps to ensure greater coherence between the LNG terminal offering and the GRTgaz offering at the PITTMs.

Moreover, the users of regulated LNG terminals suffer capacity overruns without being responsible for them, since under certain circumstances the emissions from the terminals are decided by the terminal operator according to the management constraints concerning LNG tank storage.

CRE considers that penalties for overruns in this case are not appropriate. It has submitted for consultation the principle of no longer penalising for these overruns. The majority of participants were in favour of this change.

It has beed decided that overruns at the PITTMs will be charged at the same price as the daily tariff.

Capacity transfers are freely authorised at the PITTMs and without extra charge, as full transfers or transfer of usage rights.

1.4.3 Regional tariff levels (NTR)

1.4.3.1 Recap of the history of the formation of NTRs

The regional tariff level (NTR) applicable to each delivery point reflects the cost of gas transmission from the main network to the point of delivery in question.

The current NTRs have not been revised since the opening of the gas market in 2004. For GRTgaz, the NTRs were set in particular according firstly to the investments required to develop the regional network (pipelines) and secondly, to the anticipated flows and quantities at the delivery points in question. The calculation method for the NTRs that applies to the new connections is part of the continuity of the historic method and is described on the GRTgaz website[25].

For TIGF, the same formula defined in 2004 is still being applied for all new connections. It takes account of the distance to the main network and the diameter of the pipelines[26].

Thus, the distance to the main network is one of the NTR determination factors, but is not the only cost driver taken into account in the NTR calculation.

1.4.3.2 The need to revise the current NTR system

The current NTR system leads to very significant transmission tariff discrepancies between the delivery points (from 0 to 29 on the GRTgaz network and from 0 to 15 on the TIGF network). These discrepancies may give rise to disconnections from the transmission network for sites with excessive NTRs. However, any loss of capacity subscriptions relating to disconnections involves an economic loss for the community and a rise in the gas transmission tariff for the other network users. In addition, the costs borne by the connected sites are not strictly proportional to the distance, particularly in the case of networks that have been broadly depreciated.

Moreover, the maximum transmission tariff discrepancies between two sites, i.e. the sum of the charges for the regional network and the main network, are much higher in France than in other European countries.

Finally, over the years, developments of the transmission network have led to modifications to its organisation, since the main network has been extended in places and, in others it has been reclassified as a regional network. As such, some regional tariff levels are not correlated correctly to their current distance to the main network.

In view of these elements, that were discussed during the public consultations in February 2016 and July 2016, CRE deems it necessary to develop the NTR system in order to introduce more equal balancing, limiting the tariff discrepancies between the sites. This NTR reform has become all the more necessary because the regulated sales tariffs (TRV) used to operate partial equalisation for the end customers, with 6 price levels (instead of the 29 NTRs on the GRTgaz network and 15 on the TIGF network). The switch to market offering means that some sites with a high NTR are facing big increases in their transmission bill.

1.4.3.3 Changes to the regional tariff levels (NTR) on 1st April 2017

CRE has studied along with the TSOs and presented to the public consultation in February 2016 three NTR revision methods, two of which operate a break with the existing system by implementing a direct correlation between the distance to the main network, considered to be the main cost driver, and the NTR: the methods proposed (known as methods 1[27] and 3[28]) consist in calculating a new NTR for each delivery point according to the distance to the main network. Method 3 differs from method 1 insofar as the NTR increases are not applied, with the NTR allocated to the site being the lower between the recently calculated NTR and the historic NTR.

Method 1, which uses the distance to the main network as single criterion for setting the NTR, leads to considerable transmission cost increases for some sites and constitutes too great a departure from the current system. This may be explained in particular by the fact that the distance is not the only factor taken into account when attributing NTRs.

With regard to method 3, in their response to the first public consultation, several participants highlighted the fact that it should be part of a trajectory of development towards a better reflection of costs, i.e. a structure in which the NTR of each site would be calculated using a rigorous method. CRE shares this analysis. However, application

[25] Link to the GRTgaz method for calculating the NTR.
[26] Link to the TIGF method for calculating the NTR.
[27] Method 1 involves allocating a new NTR to each site, calculated according to the current distance of the site to the main network for GRT-gaz.
[28] Method 3 is based on the calculation of a new NTR for each site according to the distance to the main network for GRTgaz and the distance and diameter in the case of TIGF. This new value is only used if it is lower than the historic value; hence, the NTR of a site may only decrease or remain unchanged.

of method 3 would lead to considerable increases in the unit tariff over the first few years for transmission across the regional network, since the NTR increases would not have been applied.

CRE has therefore put implementation of these two methods to one side.

In the consultation of July 2016, CRE proposed the employment of method 2, which consists in limiting the NTR system by setting the maximum NTR to a level that is lower than the current level. It proposed to set this maximum NTR at 8 or 12 from 1st April 2017, indicating its preference for a limit of 8. Thus, all sites with a NTR above 8 (or 12) under the ATRT5 tariff, would see their NTR set at 8 (or 12). The NTR of the remaining sites would remain unchanged. This limit to the maximum NTR will have the effect of increasing the transmission capacity charge on the regional network, whilst maintaining the TSO income at a constant level.

The majority of participants at the public consultation consider, as CRE, that it is advisable to introduce more equalisation to the NTR system. Nevertheless, a sizeable majority of shippers are not in favour or have expressed reservations regarding the method proposed by CRE at its consultation in July 2016:

- some shippers expressed their preference for gradual or deferred implementation of the reform, insofar as they have made contracts lasting several years for certain firm commercial offers based on the current NTR structure;
- other participants expressed their wish to limit the increase to the regional capacity charge that would result from restricting the NTR to 8; they therefore recommend a restriction to 12;
- finally, several participants are not in favour of method 2 and request the continuation of work to reform completely the NTR attribution system.

CRE considers that sufficient visibility has been given to the reform during the preparation of the ATRT6 tariff and does not wish to defer its implementation. Nonetheless, it considers that a reform of the NTR consisting of taking a middle path between the 8 and 12 limits, would help to contain the increase to the unit tariff for transmission across the regional network, whilst being a benefit to all users by avoiding disconnections on infrastructures representing considerable investments. As such, the establishment of a maximum NTR set at 10 would enable these objectives to be met.

Consequently, CRE will introduce a maximum NTR of 10 for the GRTgaz and TIGF networks on 1st April 2017, which, all other things being equal, will cause an increase to the regional network transmission capacity unit charge of +3.1% for GRTgaz and +4.2% for TIGF.

The ATRT6 tariff is not planned to increase the regional network charges in 2017 in order to smooth out the impacts of the various changes introduced by the ATRT6 tariff at that time (NTR reform, main/regional network rebalancing).

CRE will continue with its ideas concerning a complete reworking of the NTR system so as to offer a better reflection of the changes to the network, with a view to possible application in the ATRT7 tariff.

Finally, in the case of a network expansion where at least two customers are connected to the same facilities, regional network expansions are currently financed through the NTR level.

The NTR reform will lead to the establishment of a maximum NTR set at 10. Thus, an expansion of the regional network could not lead to a NTR being above this maximum value.

In order to avoid connections that are not economically justified, the share of costs associated with the expansion and that is not covered by the NTR, will be dealt with in the same way as a connection: these costs are borne by GRTgaz and TIGF customers, pro rata with their capacities.

1.4.4 Modification to the distribution of connection costs

1.4.4.1 Principles

Article L. 453-6 of the Energy Code stipulates that "*in the case of a connection project to the gas transmission system, the transmission system operator may request a financial contribution from the requesting party in view of the expenditure noted by the Energy Regulatory Commission. The principles of this contribution are submitted in advance for the approval of the Energy Regulatory Commission.* "

Under the ATRT5 tariff, the consumers pay all the costs for the connection facilities, connections and stations, in return for these facilities being available to them. Similarly, if a station's flow is increased, the TSOs will adapt it at the customer's expense.

In order to facilitate the connection of new customers or the increase in subscriptions by adapting existing stations, CRE submitted to the public consultations in February 2016 and July 2016 the TSO proposal that aims to introduce a cost share for connection facilities, which the customer will not pay for. The costs relating to this share will be borne by the transmission tariff.

The customer's financial contribution would be at least equal to 50% of the connection or station adaptation cost for both TSOs.

The cost share, which would not exceed 50%, would be calculated so that the connection costs borne by the tariff remain lower than the income generated over 10 years by the connection or reinforcement concerned. Hence, this cost share would not be able to lead to an increase in the overall level of the tariff.

The majority of participants at the public consultation were in favour of implementing this type of measure. Furthermore, they share the analysis of CRE regarding harmonisation and the 50% minimum threshold for the financial contribution to the connection cost.

1.4.4.2 Calculation methods for the distribution of connection costs between the customer and the tariff

CRE is using the method for distributing the connection costs between the customer and the tariff as presented at the public consultations in February and July 2016. In this method, the financial share required from the customer corresponds to the connection cost minus the future transmission revenue that the customer will pay over a ten-year period. This mechanism helps to guarantee a profitable investment for the tariff over a period less than or equal to 10 years. The customer's financial share may not be less than 50% of the connection cost.

During feasibility studies, the TSOs will determine:
- the investment cost (I) required to build or adapt the connection and the delivery station;
- the transmission revenue (R) generated by the new customer over ten years, discounted at the TSO tariff WACC (main network exit tariff, tariff on the regional network and delivery tariff).

Two scenarios may be seen regarding whether the 50% threshold of responsibility has been reached or not:
- if the transmission revenue calculated over ten years and discounted at the WACC is below 50% of the cost of investment, the customer pays the difference between the investment costs and the transmission revenue generated by the customer over ten years (I-R);
- if the transmission revenue calculated over ten years and discounted at the WACC is above 50% of the cost of investment, the 50% responsibility ceiling is reached and the customer therefore pays 50% of the connection investment cost (I*50%).

1.4.4.3 Considerations

The tariff's responsibility for a share of the connection costs comes with considerations aimed at securing the mechanism.

- For industrial customers

In return for the agreed discount, the customer signs a future capacity booking contract (CRAC) with the TSO in which they undertake to book or get others to book the capacity used for the calculation for the period used to calculate the share responsibility (period not exceeding 10 years).

- For public distribution networks

As the DSO connections have different features from those of industrial consumers, the terms and conditions for applying the mechanism must be adapted. Indeed, since the DSOs are not themselves the ones booking the capacities, they are not in a position to sign a future capacity booking contract.

- In the case of new public service concessions (DSP), the DSOs send the TSO their hourly flow forecasts for 10 years as well as the total annual potential forecast for each year from year 1 to year 10. The TSOs apply standard modulation such as heating to this annual consumption (annual modulation over 100 days). In the event that the modulation deviates from the standard, the DSOs indicate their modulation forecast based on their best possible forecasts. The hourly flow forecasts for 10 years should be consistent with the forecasts that the DSOs integrate into their responses to invitations to tender, as well as with those sent to CRE within the framework of the ATRD tariff. The annual consumption elements used year after year and which the DSOs use to calculate B/I[29] profitability must remain confidential. The TSOs agree to respect the confidentiality of this data.
- In the case of a station being adapted, the DSOs send the TSO the best annual, daily and hourly consumption forecasts, based upon which the TSOs will calculate the profitability of the project. The DSOs supplement this with information on the number of years they are taking into account for their own profitability calculation (B/I).

1.4.4.4 Special cases

- Development of existing facilities

[29] B/I is the economic criterion used by GRDF to assess the profitability of its distribution network development investments.

In the case where the development of an existing facility would involve changing the distribution network connection to the transmission network, only the difference between the capacity contracted by the site prior to the disconnection from the distribution network and the future contracted capacity after its connection to the transmission network, is used to calculate the tariff's financial share of the costs of connection to the transmission network, after validation of the assumptions with the DSO concerned.

- Connection or station reinforcement requiring reinforcement of the transmission network

Currently, the costs of enhancing the transmission network to increase the flow of a branch are borne by all the customers connected to the transmission network. The implementation of a development discount should increase the number of connections, which could lead to costs rising for all the existing customers if network reinforcements are required.

In order to limit the costs for the community, the extra cost attached to enhancing the network is integrated into the calculation of the share of connection costs payable by the customer, on a pro rata basis according to the customer's needs. Thus, the investment cost (I) used to determine the connection share covered by the tariff would be made up from the cost of the connection facilities plus the reinforcement cost, calculated on a pro rata basis according to the customer's needs.

If the discount thus calculated is less than the pro rata network reinforcement costs, then the customer will pay for all connection facilities, as is currently the case. The customer does not benefit from a share of the costs being covered by the tariff, but neither is the customer responsible for the enhancement work.

- Connection or station reinforcement requiring expansion of the transmission network

The share of costs associated with the expansion and that is not covered by the increase to the NTR, is treated in the same way as a connection (c.f. paragraph 1.4.3.3): in this case, calculation of the share of the expansion costs payable by the customer (which corresponds to the expansion cost not covered by the NTR increment, calculated on a pro rata basis according to the customer's needs) is added to the connection cost. The discount mechanism described above is applied to this increased connection cost.

1.4.5 Inter-operator compensation mechanisms

1.4.5.1 Compensation from TIGF to GRTgaz for a share of the revenue received at the Pirineos interconnection exit point

The transit route from the north of France to Spain crosses GRTgaz and TIGF zones. Until the creation of the single marketplace, the user of the network on this route will pay GRTgaz the entry charge and the North-South link charge; and will pay TIGF the Pirineos exit charge. These sums correspond to the service provided to the network user on the GRTgaz and TIGF networks in their respective zones.

As specified in paragraphs 1.4.2.3 and 1.4.2.4 of this resolution, the alignment of the transit cost between the two routes to Spain and Italy at the time the North-South link is removed, will give rise to the transfer of a portion of the revenue initially received from the North-South link (in the GRTgaz zone) at the Pirineos exit point (situated in the TIGF zone). However, the costs arising through use of this transit route are still borne by the two TSOs in unchanged proportions.

Hence, to avoid cross subsidy between the main network and the regional network, starting on the date of creation of the single marketplace, a financial flow has to be introduced between GRTgaz and TIGF. This payment by TIGF to GRTgaz, relating to the costs borne by GRTgaz for the use of this transit route, will equate to the increased Pirineos tariff caused by the transfer of North-South revenue to the Pirineos charge at the time the single marketplace is created. This will then change with inflation on 1st April of every year thereafter.

The conditions for setting up this flow, the option of which is covered in the Tariffs Network Code, will be defined in a future CRE resolution.

100% of the discrepancies relating to this payment will be covered by the CRCP mechanism. This mechanism will not affect the network users, who will continue to pay their total bill for the Pirineos exit to TIGF.

1.4.5.2 Inter-operator contract for access by GRTgaz to the TIGF network

To transport the gas from the Fos Tonkin and Fos Cavaou LNG terminals to the north of France, GRTgaz may make use of the TIGF transmission network. As such, GRTgaz and TIGF have signed a service-provision contract whose amount (of around €33 M per year) is incorporated into the net OPEX trajectory for each of the two TSOs.

1.4.5.3 Fee paid by Fluxys to GRTgaz for transmission from the Dunkirk LNG terminal to the Belgian border

The *open season* held by GRTgaz between 2010 and 2011, in coordination with Fluxys, allowed the launch of the investments necessary to create the Alveringem interconnection point. Capacities entering Belgium from the

Dunkirk LNG terminal are marketed by Fluxys and transmission on the GRTgaz network is the subject of a service provision from GRTgaz to Fluxys.

In its resolution of 12th July 2011[30], CRE indicated, in respect of the forecast costs for development of these capacities, that the tariff invoiced by GRTgaz to Fluxys for transport from the terminal to Belgium would be €45/MWh/d/year. CRE has stipulated that this amount would be reassessed according to the real level of investment.

In compliance with the said resolution, CRE has recalculated the price of the service, taking into account the costs on completion of the project. As a result, on 1st April 2017, the cost of the service will increase to €43.60/MWh/d/year.

1.4.5.4 Distribution of revenue to the Trading Region South gas transfer point

GRTgaz receives all revenue at the Trading Region South from customers with contracts with both TSOs and pays back to TIGF a share of this revenue. The amount refunded is set through an agreement between the two TSOs.

[30] Resolution of 12th July 2011 forming a ruling 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

2. PARAMETERS AND TRAJECTORY OF THE TARIFF FOR THE USE OF GRTGAZ AND TIGF NATURAL GAS TRANSMISSION NETWORKS

2.1 Allowed revenue for tariff period 2017-2020

Article L.452-1 of the Energy Code states that "*the tariffs for the use of the transmission systems and natural gas distribution systems and liquefied natural gas facilities [...] shall be established in a transparent and non-discriminatory manner and shall cover all the costs borne by the operators of these networks insofar as such costs correspond to those of an efficient network or facility operator*".

In application of these provisions, the projected GRTgaz and TIGF charges to be covered by the ATRT6 tariff have been determined by CRE on the basis of all costs needed for the transmission systems to function, as communicated to it by the TSOs. As part of this, GRTgaz and TIGF submitted their tariff applications to CRE in March 2016. These applications were updated in May 2016 for TIGF and in July 2016 for GRTgaz. In particular, the TSOs' projected charges have incorporated the costs associated with executing their public service obligations.

CRE has carried out an in-depth analysis of all expense items submitted by GRTgaz and TIGF for the period 2017-2020, in order to ensure that the projected charges used to define the ATRT6 tariff are similar to those of efficient operators. To this end, it has conducted two external studies:

- an audit of GRTgaz and TIGF's operating costs for the period 2013-2020[31];
- a study on the assessment of the financial parameters used to calculate capital expenditure[32].

In its consultation in July 2016 CRE presented the TSO tariff applications, as well as its preliminary analyses on the level of operating costs and return on assets. The stakeholders who answered questions on the tariff level had mixed views.

With regards to net operating expenses, the two TSOs and several trade unions criticised some of the adjustments recommended by the auditor. Conversely, a number of suppliers and industrial companies highlighted the fact that costs must be estimated accurately so as not to overestimate the ATRT6 tariff, and stressed the importance of keeping operating costs under control.

Opinions about the WACC level were also divided: the TSOs, LNG terminal operators, and their shareholders advocated a continuation of the current return rate and of the differentiation between gas distribution and gas transmission, whereas industrial associations and some suppliers favoured the reduction in WACC recommended by CRE.

[31] Pöyry report on GRTgaz and TIGF's operating costs for the period 2013-2020
[32] FTI – Compass Lexecon study on the financial parameters used to calculate capital expenditure

2.1.1 TSO tariff applications

2.1.1.1 GRTgaz tariff applications

The projected allowed revenue request presented by GRTgaz in July 2006 is broken down as follows:

Allowed revenue requested by GRTgaz for the ATRT6 period

GRTgaz, in €m$_{current}$	Actual 2015*	2017	2018	2019	2020	Average 17-20
Net operating expenses (excluding energy)	624	707	744	766	781	**750**
Energy costs	113	97	97	92	96	**95**
Normative capital charges	1,001	1,120	1,141	1,207	1,204	**1,168**
Clearance of the balance in the revenues and expenses clawback account (remainder from previous clawback accounts + 2015 balance + 2016 estimate)	-18.1	-26[33]	-30	-30	-30	**-29**
Recovery of the tariff difference linked to the ATRT5 period	-	19	58	-	-	**19**
Total allowed revenue requested	**1,721**	**1,918**	**2,009**	**2,035**	**2,051**	**2,003**
Change	-	-	*+4.8%*	*+1.3%*	*+0.8%*	*+2.3%*

* The actual net operating expenses for 2015 have been restated from income linked to the renewal, renovation and repair of delivery points and public distribution connection facilities. The transfer of these "3R charges" from the DSOs to the TSOs was introduced by the proceedings of 10 March 2016, regarding the usage tariff for public GRDF natural gas distribution systems.

The GRTgaz application for the ATRT6 tariff would lead to an increase in allowed revenues in 2017 of +€197m, or 11.4% compared to the 2015 results. During the period 2017-2020, the allowed revenue would then increase by 2.3% per annum on average.

The GRTgaz application includes two charge categories:

- so-called "base" expenses: according to GRTgaz, these expenses correspond with its current activities (similar category to the ATRT5 tariff);
- expenses linked to the "GRTgaz 2020" project: this corporate plan presented by GRTgaz includes charges linked to certain new obligations (legislative, regulatory and environmental), as well as to a certain number of new projects for the ATRT6 period. This can be divided into thirty subject areas, organised into four broad categories:

  (i) "GRTgaz, committed to an ambitious and sustainable energy transition": support for new gas sectors (biomethane, Power to Gas, green transport), promoting efficient uses for gas, communication campaign on the image of natural gas...;

  (ii) "GRTgaz, a role model in terms of energy transition": monitoring greenhouse gas emissions in the transmission system, leakage reduction, optimising the network's energy usage...;

  (iii) "GRTgaz, an independent operator in pursuit of extrication": extricating CRIGEN's R&D activities, bolstering the legal function, internalisation of gas demand forecasts...;

  (iv) "GRTgaz, an operator that adapts to changes in its environment": incorporation of regulatory and technical changes, project to convert the L network to H, improving safety at facilities, reliance on digital technologies...

[33] In its application GRTgaz added to the -€30m instalment from the clawback account in 2017 a further €4.4m associated with covering the lost earnings for GRTgaz due to non-collection of the royalty owed by Fluxys for transmission services provided by the French TSO while the Dunkirk terminal was not in service. Coverage for these lost earnings is provided for in the deliberation of 12 July 2011, regarding the connection charges for the Dunkirk LNG terminal and the development of a new interconnection with Belgium at Veurne for up to one year starting November 2015. Later in the deliberation, the sums to be covered are incorporated into the clawback account balance at 31 December 2016, and then cleared over four years.

In addition, GRTgaz requests an real pre-tax WACC of 6.5%, identical to the current WACC for the ATRT5 tariff. The projected normative capital charges include, in 2019, the commissioning of the Val de Saône and Gascogne-Midi project assets in the TSO's RAB, which are needed for the creation of the single marketplace.

2.1.1.2 TIGF tariff application

The projected allowed revenue request presented by TIGF in May 2016 is broken down as follows:

Allowed revenue requested by TIGF for the ATRT6 period

TIGF, in €m$_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
Net operating expenses (excluding energy)*	66	72	72	77	79	**75**
Energy costs	9	9	9	12	12	**10**
Normative capital charges	158	177	184	195	202	**189**
Clearance of the balance in the revenues and expenses clawback account (remainder from previous clawback accounts + 2015 balance + 2016 estimate)	-1.3	1.6[34]	1.6	1.6	1.6	**1.6**
Total allowed revenue requested *Change*	**231** -	**259** -	**266** *+2.8%*	**285** *+7.2%*	**296** *+3.8%*	**276** *+4.6%*

* The actual net operating expenses for 2015 and those requested by TIGF for 2017-2020 have been restated from income linked to the renewal, renovation and repair of delivery points and public distribution connection facilities. The transfer of these maintenance charges from the DSOs to the TSOs was introduced by the deliebration of 10 March 2016, regarding the usage tariff for public GRDF natural gas distribution systems.

TIGF's application would lead to an increase in allowed revenue in 2017 of +€27m, or +11.8% compared to the 2015 results. During the period 2017-2020, the allowed revenue would then increase by 4.6% per annum on average.

In addition to a comparable charging scope to the ATRT5 tariff, TIGF's application notably includes an increase in operating costs, in 2019, following the creation of the single marketplace, as well as a research and innovation (R&I) programme. This programme covers:

- preservation of biodiversity;
- reduced disruption from infrastructure;
- support in developing the biomethane sector: designing injection points and overhaul facilities;
- optimisation of facility integrity to ensure facility availability;
- adaptation to the digital transition;
- H_2 smart grids: acquisition of expertise in "Power to Gas" pilots (Jupiter 1000 project).

In addition, TIGF requests an real pre-tax WACC of 6.5%, identical to the current WACC for the ATRT5 tariff. The projected normative capital charges include, in 2019, the commissioning of the Gascogne-Midi project assets in the TSO's RAB, which is needed for the creation of the single marketplace, as well as some of the expenses linked to the STEP project (MidCat first step) in 2020.

2.1.2 CRE analysis of the net operating expenses

The net operating expenses mainly consist of the following items:

- gross operating expenses: energy, external consumption, power plant costs, staffing costs, taxes;
- operating products deducted from the gross expenses covered by the tariff: connections, income from services, and capitalised production.

During the period 2013-2015, the actual net operating expenses of GRTgaz and TIGF were significantly lower than the projected costs effectively covered by the ATRT5 tariff. The total actual difference in expenses not included in the revenues and expenses clawback account is €115m in GRTgaz's favour, or 5.1% of the forecast expenses, and €15m in TIGF's favour, or 7.2% of the forecast expenses.

[34] TIGF requests the tariff difference for the ATRT5 period be recovered via the 2016 clawback account.

So that users can benefit from the efficiency gains made by GRTgaz and TIGF during the ATRT5 period, CRE shall use the costs achieved by the TSOs during this period as the benchmark for its work. As such, CRE has used data from financial years 2013-2015 to assess the projected trajectories submitted by the operators, while still taking into account new projects that may impact the cost levels for GRTgaz and TIGF during 2017-2020.

The projected net operating expenses submitted by GRTgaz for the period 2017-2020 are as follows:

GRTgaz application - Net operating expenses

GRTgaz, in €m current	Actual 2015*	2017	2018	2019	2020	Average 17-20
Net operating expenses - Updated GRTgaz application Change (%)	**738**	**804** +9.0%	**840** +4.5%	**858** +2.1%	**877** +2.2%	**845** +2.9%
- of which "base" - of which "GRTgaz 2020"		763 40	782 58	807 51	828 49	795 50

* the actual 2015 results were restated for the 3R charges (by €15.7m) to maintain a like-for-like basis with the period 2017-2020.

The operator established its forecasts by distinguishing between:

- base expenses corresponding to those associated with a business scope GRTgaz defines as constant compared to the ATRT5 period (€795m per annum on average);
- costs associated with the GRTgaz 2020 project, as defined by the operator to meet its new obligations and implement certain new projects to accompany its energy transition (€50m per annum on average).

The GRTgaz application would lead to an increase in net operating expenses in 2017 of €66m compared to the 2015 results (+9.0%), of which €40m is linked to the GRTgaz 2020 project. Excluding energy, the increase between the actual 2015 and requested 2017 figures is +13.3%. During the period 2017-2020, the net operating expenses will then increase an average of +2.9% per year.

The projected net operating expenses presented by TIGF for the period 2017-2020 are as follows:

TIGF application - Net operating expenses

TIGF, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
Net operating expenses - TIGF application* Change (%)	**75**	**80** +7.6%	**81** +0.7%	**89** +9.8%	**92** +3.5%	**85** +4.6%
- of which R&I programme		2.4	2.3	2.5	2.5	2.4

* TIGF's actual 2015 results and application were restated for the maintenance costs for delivery points and distribution connections (by €3.9m) to maintain a like-for-like basis with the period 2017-2020.

TIGF's application would lead to an increase in 2017 of €5.7m compared to the 2015 results (+7.6%). Excluding energy, the increase between the actual 2015 and requested 2017 figures is +9.3%. During the period 2017-2020, the net operating expenses will then increase an average of +4.6% per year.

To set the level of net operating expenses to be covered, CRE carried out an in-depth analysis of the GRTgaz and TIGF applications, focusing particular attention on:

- data from the TSOs' accounts for the years 2013 to 2015;
- assumptions regarding changes in expenditure for the years 2016 to 2020 as submitted by the TSOs;
- results of an audit into the TSOs' actual and projected net operating expenses for financial years 2013 to 2020;
- responses to the public consultation in July 2016: 37 participants (GRTgaz, TIGF, 12 shippers or shipper associations, 3 industrial companies, 3 infrastructure operators, the umbrella trade union for TIGF, an employee union, and 15 companies in the green energy sector) responded to questions on the level of operating expenses to be covered by the ATRT6 tariff.

2.1.2.1 Main conclusions

In the public consultation in July 2016, CRE presented the adjustments recommended by the external audit into the operators' applications. Compared to the initial applications, these adjustments totalled:

- approx. -€78m on average per year for GRTgaz;
- approx. -€10m on average per year for TIGF[35].

In the July 2016 public consultation, CRE stated that GRTgaz had submitted a modified tariff application at the beginning of July 2016. This application was €18m less per year on average than the initial application (of which €3m was linked to the GRTgaz 2020 project). The change was mostly due to reduced demand for energy costs.

TIGF has not submitted a new application since it updated its tariff documentation in May 2016 to reflect changes from the first version of the audit report.

CRE requested the external auditor examine the updated GRTgaz application.

a) GRTgaz

Adjustments recommended by the external auditor

Upon completion of its analyses, the auditor recommends the following adjustments:

GRTgaz - Adjustments recommended by the auditor

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
Adjustments recommended by the auditor and presented in the public consultation on 27 July 2016 Compared to the initial GRTgaz application (%)	**-60** -7.3%	**-80** -9.4%	**-80** -9.1%	**-92** -10.2%	**-78** -9.0%
Final adjustments recommended by the auditor Compared to the updated GRTgaz application (%)	**-43** -5.3%	**-62** -7.3%	**-56** -6.5%	**-63** -7.2%	**-56** -6.6%
Difference between the two versions of the report	-17	-18	-24	-29	-22

The differences given, of €20m per year on average, are due to a revision of the adjustment suggested by the auditor to the "energy" item, following the updated tariff application submitted by GRTgaz in July 2016.

The total adjustments suggested by the auditor are €56m per annum on average.

Given the auditor's conclusions, the supplementary documents provided by GRTgaz to the CRE, and all of the information brought to its attention, CRE has decided to retain the adjustments recommended by the auditor, valuing €36m per annum on average. These adjustments primarily concern the GRTgaz 2020 project (€17m) and the service products (€10m).

CRE has not retained the adjustments suggested by the auditor in terms of staffing costs, changes to storage contracts, and maintenance expenses. CRE has only retained some of the adjustments recommended for the GRTgaz 2020 project (€17m per year on average retained out of the €22m of adjustments recommended by the consultant). The adjustments retained by CRE are described in section 2.1.2.3.

GRTgaz - Adjustments recommended by the auditor and retained by the CRE

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
Adjustments suggested by the external auditor and retained by the CRE	-28	-33	-38	-43	-36

Other adjustments

CRE has retained the following additional adjustments:

[35] This sum corresponds to the total adjustment of -€6m on average per year as presented in the public consultation in July 2016, excluding adjustments linked to the maintenance costs for delivery points and distribution connections.

- an adjustment to the "energy" item aiming to bring volumes up to the levels of fuel consumption observed in 2015 and to take market price changes into account;

GRTgaz - Additional adjustment retained by CRE for the "energy" item

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
Additional "energy" adjustment retained by the CRE	-4	-7	-6	-9	-7

- an adjustment to staffing costs, in order to standardise assumptions for the national minimum wage in the electricity and gas industries mentioned in the various ongoing tariff documents (TURPE[36] 5 HTB and HTA-BT, ATTM5[37]), with an overall neutral effect on all of the listed tariffs.

GRTgaz 2020 project

CRE welcomes the launch of the GRTgaz 2020 project, as it involves the TSO in the energy transition process and the preparation for the future of gas transmission systems. However, it also believes that some aspects of the programme are simply normal changes in GRTgaz operations and should be carried out using the resources covered by the base charges at constant scope, whilst some of the other new activities could be carried out in a more efficient way by the TSO. Furthermore, a small number of the activities planned by GRTgaz are too far removed from its core business area. As a result, CRE has retained an adjustment of €17m per annum on average for the GRTgaz 2020 project.

Analysis of GRTgaz's proposed efficiency

During the ATRT6 tariff period, GRTgaz claims to have incorporated a productivity of 1.7% for a total of operating expenses it deems "manoeuvrable", which make up 20% of its base net operating expenses. CRE notes that the scope of what the operator considers "manoeuvrable" is very small.

Moreover, when accounting for the efficiency target submitted by GRTgaz and the adjustments mentioned previously, the annual average for net operating expenses (excluding energy) is €713m for the next tariff period. The change between the actual 2015 and projected 2017 figures is +8.7%. The annual net growth rate anticipated in the net operating expenses (excluding energy) is +2.8% for the period 2017-2020. This change is more than the inflation forecasts, and would result in a cost increase of 17.9% between the reported 2015 figures and forecast 2020 figures.

Regarding these elements, CRE has decided to retain an additional efficiency objective of 0.5% per year for the total covered net operating expenses (excluding energy) between 2015 and 2017, and then 1% per year from 2018 onwards:

[36] TURPE: Usage Tariff for Public Electricity Networks
[37] ATTM: Third-Party Access to LNG Terminals

GRTgaz - Additional efficiency retained by the CRE

GRTgaz, in €m current	2017	2018	2019	2020	Average 17-20
Additional efficiency retained by the CRE	-7	-14	-21	-28	-17

Trajectory of net operating expenses resulting from the adjustments retained by the CRE

In summary, the following table and graph show the trajectory for the net operating expenses resulting from the adjustments retained by CRE for the ATRT6 tariff.

GRTgaz - Adjusted trajectory - Net operating expenses

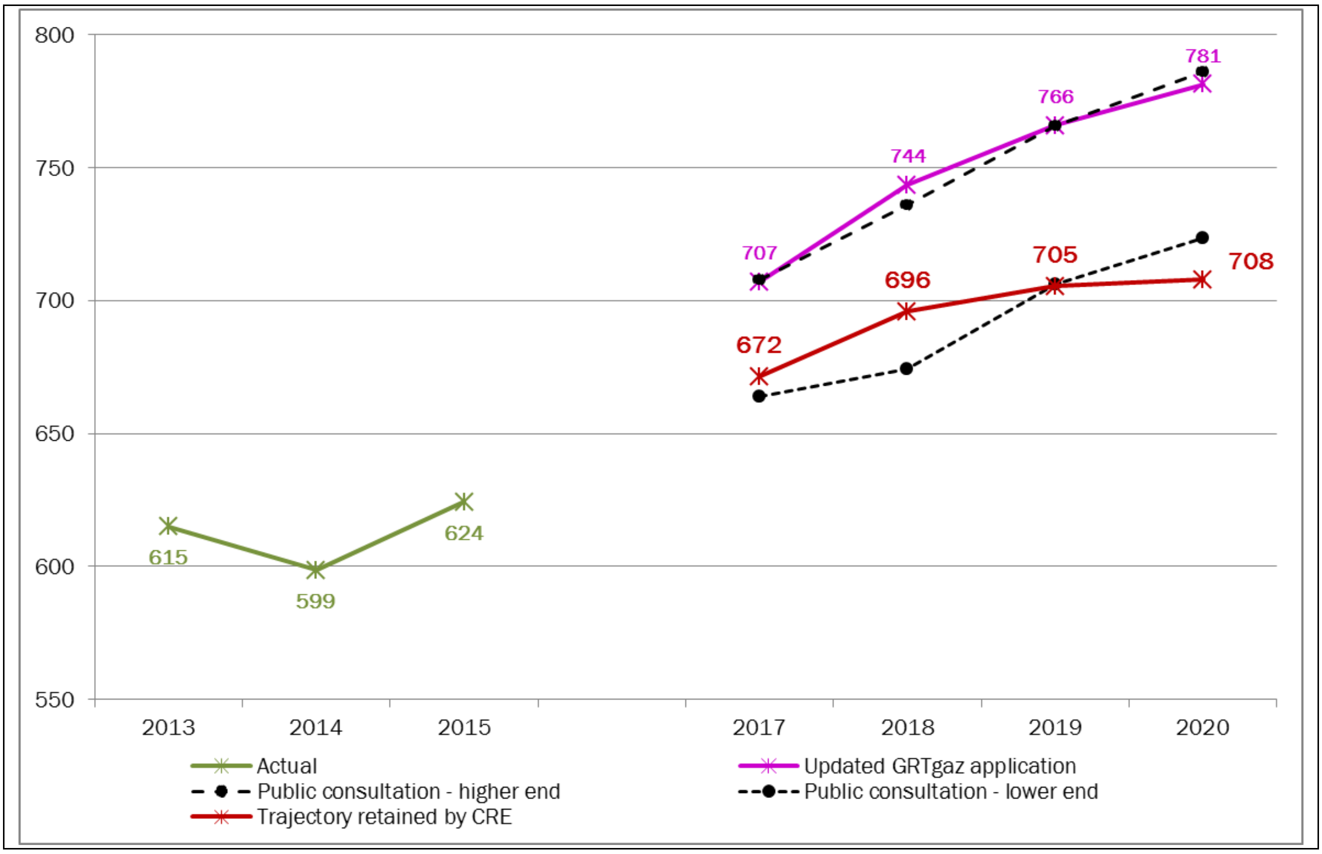
GRTgaz, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application - Energy		97	97	92	96	95
Adjustment retained by the CRE		-4	-7	-6	-9	-7
Retained trajectory - Energy	113	92	90	87	87	89

GRTgaz, in €m current	Actual 2015*	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application, excluding energy		707	744	766	781	750
Adjustments suggested by the external auditor and retained by the CRE - base - GRTgaz 2020		-16 -12	-20 -13	-18 -20	-22 -21	-19 -17
Other adjustment retained by the CRE		-0.5	-1	-2	-2	-1
Additional efficiency		-7	-14	-21	-28	-17
Trajectory retained by the CRE, excluding energy Change (%)	624	672 +7.6%	696 +3.6%	705 +1.4%	708 +0.3%	695 +1.8%

* the actual 2015 results were restated for the 3R charges (by €15.7m) to maintain a like-for-like basis with the period 2017-2020.

Thus, the annual net growth rate in GRTgaz's net operating expenses (excluding energy) retained for the ATRT6 tariff is +1.8% for the period 2017-2020. The increase between the actual 2015 and projected 2020 figures is 13.4%.

Graph 1: Trajectory of GRTgaz's net operating expenses, excluding energy



b) <u>TIGF</u>

<u>Adjustments recommended by the external auditor</u>

Upon completion of its analyses, the auditor recommends the following adjustments:

TIGF - Adjustments recommended by the auditor

TIGF, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
Final adjustments recommended by the auditor*	-5	-10	-11	-14	-10
Compared to the TIGF application (%)	-5.6%	-12.6%	-12.6%	-14.9%	-11.6%

* apart from the suggested adjustment for the transfer of maintenance costs for delivery points and distribution connections (€3.9m adjustment), the TIGF application was restated to this effect in order to maintain a like-for-like basis.

The total adjustments suggested by the auditor are €10m per annum on average.

Given the auditor's conclusions, the supplementary documents provided by TIGF to the CRE, and all of the information brought to its attention, CRE has decided to retain the adjustments recommended by the auditor, valuing €4.2m per annum on average.

CRE has not retained the adjustments suggested by the auditor with regards to staffing costs, the storage contract price and energy costs, as these have been analysed by the CRE.

TIGF - Adjustments recommended by the auditor and retained by the CRE

TIGF, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
Adjustments suggested by the external auditor and retained by the CRE	-3.8	-4.0	-4.0	-4.8	-4.2

Other adjustments

CRE has retained the following additional adjustments:

- an adjustment to the "energy" item aiming to bring volumes up to the levels of fuel consumption observed in 2015 and to take market price changes into account;

TIGF - Additional adjustment retained by CRE for the "energy" item

TIGF, in €m current	2017	2018	2019	2020	Average 17-20
Additional adjustment retained by CRE for the "energy" item	-1.4	-2.2	-3.4	-4.1	-2.8

- an adjustment for Research and Innovation (R&I) of €0.3m per year on average, as TIGF did not supply sufficient justification for some elements of the programme;
- an adjustment that affects the increase in cost levels covered, under storage repayments: the "shared resources"[38] sub-item is reassigned between the TIGF transport and storage activities using the cost allocations. The adjustments suggested by the auditor did not take into account this breakdown, and the repayment from TIGF Transport to TIGF Storage must be automatically revised downward by €1.5m per annum on average.

Analysis of TIGF's proposed efficiency

TIGF did not present a target efficiency figure in its tariff application for the ATRT6 period, but states nevertheless that it has put forward a tariff trajectory that incorporates the productivity gains from the ATRT5 period, which can cover future changes using existing resources.

After accounting for the adjustments mentioned previously, the annual average for net operating expenses (excluding energy) is €72m for the next tariff period. The change between the actual 2015 and projected 2017 figures is +5.4%. The annual net growth rate anticipated in the net operating expenses (excluding energy) is +3.0% for the period 2017-2020. This change is more than the inflation forecasts, and would result in a cost increase of 15.4% between the reported 2015 figures and forecast 2020 figures.

Regarding these elements, CRE has decided to retain an additional efficiency objective of 1% per year for the total covered net costs (excluding energy) from 2018 onwards:

TIGF - Additional efficiency retained by CRE

TIGF, in €m current	2017	2018	2019	2020	Average 17-20
Additional efficiency retained by CRE	0	-0.7	-1.4	-2.2	-1.1

[38] Rental, IT, travel, communication and governance costs

Trajectory of net operating expenses resulting from the adjustments retained by the CRE

To summarise, the following table and graph show the trajectory for the net operating expenses resulting from the adjustments retained by CRE for the ATRT6 tariff.

TIGF - Adjusted trajectory - Net operating expenses

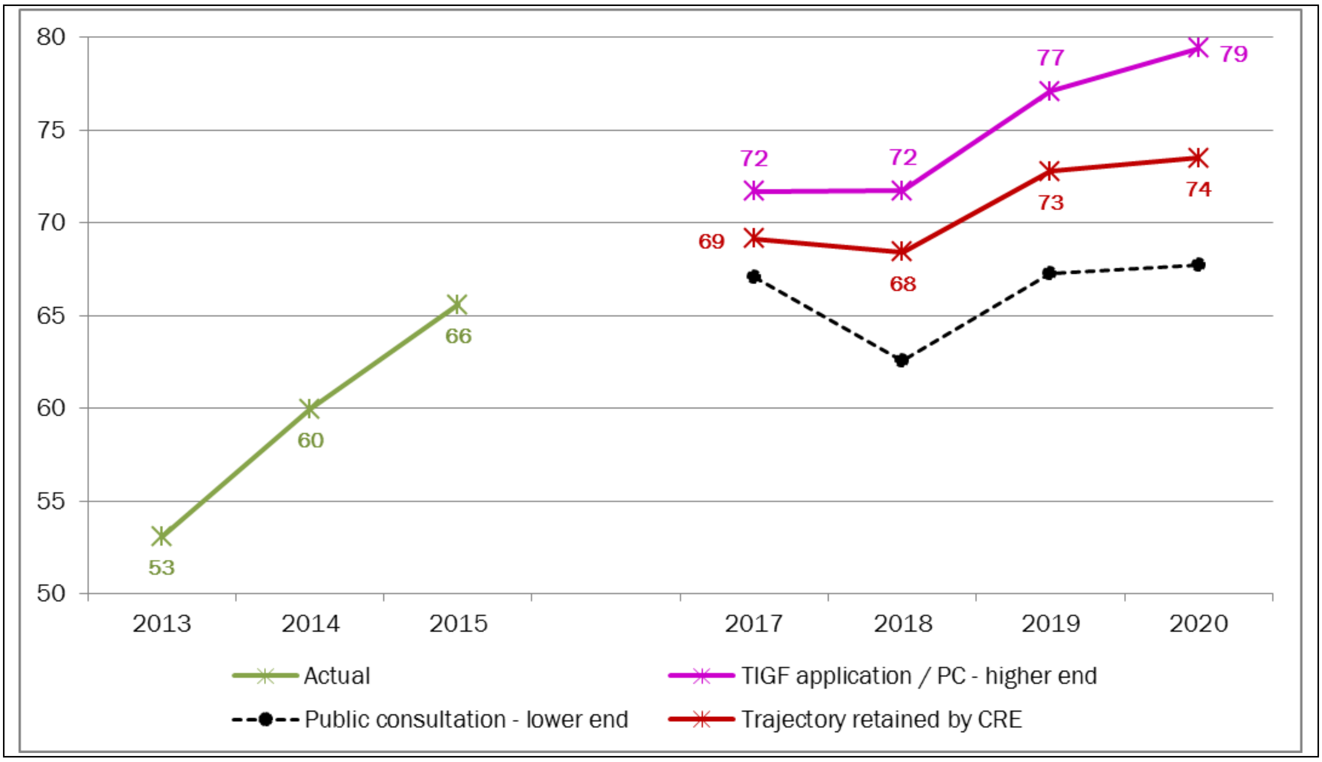
TIGF, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
TIGF application - Energy		**9**	**9**	**12**	**12**	**10**
Adjustment retained by the CRE		-1.4	-2.2	-3.4	-4.1	-2.8
Retained trajectory - Energy	**9**	**7**	**7**	**8**	**8**	**8**

TIGF, in €m current	Actual 2015*	2017	2018	2019	2020	Average 17-20
TIGF application, excluding energy		**72**	**72**	**77**	**79**	**75**
Adjustments suggested by the external auditor and retained by the CRE		-3.8	-4.0	-4.0	-4.8	-4.2
Additional adjustments retained by the CRE		+1.3	+1.4	+1.1	+1.1	+1.2
Efficiency		-	-0.7	-1.4	-2.2	-1.1
Trajectory retained by the CRE, excluding energy	**66**	**69**	**68**	**73**	**74**	**71**
Change (%)		+5.4%	-1.1%	+6.4%	+1.0%	+2.1%

* the actual 2015 results were restated for the maintenance costs for delivery points and distribution connections (by €3.9m) to maintain a like-for-like basis with the period 2017-2020.

Thus, the annual net growth rate in TIGF's net operating expenses (excluding energy) retained for the ATRT6 tariff is +2.1% for the period 2017-2020. The increase between the actual 2015 and projected 2020 expenses is 12.1%.

Graph 2: Trajectory of TIGF's net operating expenses, excluding energy



2.1.2.2 Analysis of adjustments for the "energy" item

a) <u>GRTgaz</u>

In its March 2016 file, GRTgaz submitted an application based on average energy costs of €114m per year. When updating its tariff application in July 2016, GRTgaz revised its request downward, essentially by including the prices of its latest energy purchases (made in the first quarter of 2016). These were lower than anticipated in the original application, resulting in a request of €95m per year on average. This trajectory, which is lower for the ATRT6 period, incorporates energy savings linked to several items in the GRTgaz 2020 project (such as the energy saving and leak reduction programmes) at a total of -€7.7m.

GRTgaz - Requested energy costs

GRTgaz, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
Gas (€m)	74	56	54	53	53	**54**
Fuel volumes and venting (GWh)	*1,819*	*2,009*	*1,976*	*1,935*	*1,909*	***1,957***
Technical Imbalance (GWh)	*1,208*	*1,200*	*1,200*	*1,200*	*1,200*	***1,200***
Gas price (€/MWh)[39] end of July 2016	25.3	*17.6*	*16.9*	*16.8*	*16.9*	***17.0***
Electricity (€m)	29	30	30	30	29	**30**
Volumes (GWh)	*412*	*423*	*421*	*412*	*404*	**415**
Electricity price (€/MWh)	*70.1*	*70.5*	*71.2*	*71.9*	*72.6*	***71.6***
CO_2	-	-	-	-	4	**1**
TIC[40]	5	10	10	10	10	**10**
Total energy costs (excluding fixed assets)	**108**	**96**	**93**	**92**	**95**	**94**
Capitalised gas (€m)	5	0	3	0	0	**1**
Total energy costs	**113**	**97**	**97**	**92**	**96**	**95**

CRE retains numerous adjustments in relation to this application:

- the fuel volumes have been adjusted in line with the actual 2015 level of equivalent gas;
- the level of Technical Imbalance (EBT) was aligned with historic trends;
- gas prices were updated based on the average of the first 15 forward quotes on the TTF market in October 2016. Similarly, CO_2 quotas are valued based on the first 15 EU ETS quotes in October 2016;
- the CO_2 quotas are deemed as purchased in 2017 instead of 2020.

As a result, the trajectory retained for the ATRT6 tariff is the following:

GRTgaz - Retained energy costs

GRTgaz, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
Gas (€m)	74	53	49	48	48	**50**
Fuel volumes and venting (GWh)	*1,819*	*1,903*	*1,871*	*1,830*	*1,804*	***1,852***
Technical Imbalance (GWh)	*1,208*	*1,100*	*1,100*	*1,100*	*1,100*	***1,100***
Gas price (€/MWh) October 2016	25.3	*17.7*	*16.3*	*16.5*	*16.5*	***16.8***
Electricity (€m)	29	28	28	29	29	**28**
Volumes (GWh)	*412*	*396*	*396*	*396*	*396*	***396***
Electricity price (€/MWh)	*70.1*	*70.5*	*71.2*	*71.9*	*72.6*	***71.6***
CO_2	-	1.0	-	-	-	**0**
TIC	5	10	10	9	9	**10**
Total energy costs (excluding fixed assets)	**108**	**92**	**86**	**86**	**86**	**88**
Capitalised gas (€m)	5	0	3	0	0	**1**
Total adjusted energy costs	**113**	**92**	**90**	**87**	**87**	**89**

The projected energy costs (price and volumes) will be revised during the annual updates.

b) TIGF

In its May 2016 file, TIGF submitted an application based on average energy costs of €10m per year.

[39] The gas price is an average weighted price of the TSO's stored gas and its purchases on the market.
[40] TIC: Domestic Consumption Tax

TIGF - Requested energy costs

TIGF, in €m$_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
Gas (€m)	8	7	7	7	7	7
Fuel volumes and venting (GWh)	198	227	226	188	188	207
Technical Imbalance (GWh)	113	110	110	110	110	110
Gas price (€/MWh)[41] end of May 2016	*24.5*	*20.7*	*21.7*	*22.4*	*22.8*	*21.9*
Electricity (€m)	1	2	2	5	5	3
Volumes (GWh)[42]	11	12	13	40	43	27
Electricity price (€/MWh)	*119.1*	*132.3*	*138.8*	*124.4*	*122.2*	*129.4*
CO_2	0	0	0	0.1	0.4	0.1
Total energy costs	9	9	9	12	12	10

CRE retains numerous adjustments in relation to this application:

- the fuel volumes have been adjusted in line with the actual 2015 level of equivalent gas;
- the electricity prices have been adjusted based on the cost borne by TIGF in 2015, revised downward by 10% to take into account the transition to market offer in 2016;
- gas prices were updated based on the average of the first 15 forward quotes on the TTF market in October 2016 and a price spread between PEG Nord and TRS of €1.3/MWh until the creation of the single marketplace. Similarly, CO_2 quotas are valued based on the first 15 EU ETS quotes in October 2016;
- the CO_2 quotas are deemed as purchased in 2017 instead of 2020.

As a result, the trajectory retained for the ATRT6 tariff is the following:

TIGF - Retained energy costs

TIGF, in €m$_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
Gas (€m)	8	6	5	4	4	5
Fuel volumes and venting (GWh)	*198*	*200*	*197*	*119*	*109*	*157*
Technical Imbalance (GWh)	113	110	110	110	110	110
Gas price (€/MWh) October 2016	*24.5*	*18.3*	*17.9*	*17.5*	*17.1*	*17.7*
Electricity (€m)	1	1	1	4	5	3
Volumes (GWh)	11	12	13	40	43	27
Electricity price (€/MWh)	*119.1*	*107.2*	*107.2*	*107.2*	*107.2*	*107.2*
CO_2	0	0.2	0	0	0	0
Total adjusted energy costs	9	7	7	8	8	8

The projected energy costs (price and volumes) will be revised during the annual updates.

2.1.2.3 Analysis of adjustments, excluding energy

a) <u>GRTgaz</u>

[41] The gas price is an average weighted price of the TSO's stored gas and its purchases on the market.
[42] TIGF is planning to install three additional electric compressors in the ATRT6 period and thus move towards using mainly electricity as its power source. This is in the interests of flexibility and minimising CO_2 emissions.

The approach adopted by the auditor to analyse the net operating expenses levels of GRTgaz consisted of assessing the projected trajectories submitted by the operator for each of its cost items, as compared with the actual cost levels over the 2013-2015 period and in 2015 in particular.

Industrial system

The "industrial system" item encompasses the costs of industrial real estate, R&D expenditure, major maintenance projects and all other maintenance costs (networks, measuring and compression).

GRTgaz has requested an increase of €21m to the "industrial system" item (of which €11m are linked to the GRTgaz 2020 project), or +15.8% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +1.8% per annum on average.

Industrial system, excluding R&D

With regards to the "industrial system, excluding R&D" sub-item, GRTgaz was unable to provide satisfactory justification for its changes to maintenance, compression and measurement expenses compared to the period 2013-2015. The auditor suggested maintaining the cost control measures implemented by GRTgaz during the ATRT5 period, and then an identical change in inflation for the period 2017-2020. The auditor therefore suggests a downward adjustment to this cost item, of around €3m per year on average. CRE retains this adjustment.

No further adjustments are retained by CRE for the "industrial system" item.

Therefore, the trajectory for the "industrial system" item is the following:

GRTgaz - Industrial system

GRTgaz, in €m current	Actual 2015	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application		154	166	166	162	162
Adjustments retained by the CRE*		-7	-7	-6	-6	-7
Retained trajectory	**133**	**147**	**159**	**160**	**156**	**155**

* including an adjustment linked to the GRTgaz 2020 project of €3m per year on average, detailed below.

Gas system, excluding energy

The "gas system, excluding energy" item includes the costs of contracts signed with other operators to ensure network functionality: flexibility, H/B conversion, Swiss transit at Pontarlier, royalties for TIGF and adjacent operators.

GRTgaz has requested an increase of €7m to the "gas system, excluding energy" item (of which €3m are linked to the GRTgaz 2020 project), or 5.4% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +2.9% per annum on average.

Contracts with adjacent operators

Several operators supply GRTgaz with odourisation, metering, compression, mixing and interconnection services. For these contracts, GRTgaz retains a margin of 2-5% for technical risks, depending on the service. The auditor recommends that this not be incorporated. CRE retains this adjustment, of approximately €3m per annum on average.

No further adjustments are retained by CRE for the "gas system, excluding energy" item.

Therefore, the trajectory for the "gas system" item is the following:

GRTgaz - Gas system, excluding energy

GRTgaz, in €mcurrent	Actual 2015	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application		129	135	140	141	136
Adjustments retained by the CRE		-2	-2	-3	-3	-3
Retained trajectory	**123**	**127**	**133**	**137**	**138**	**134**

Operational support

The "operational support" item includes expenditure on information systems, costs for non-industrial real estate, vehicles, and other operational support expenses.

GRTgaz has requested an increase of €20m to the "operational support" item (of which €13m are linked to the GRTgaz 2020 project), or +12.9% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +1.6% per annum on average.

Information systems

The internalisation of key skills to the Information Systems Division has allowed GRTgaz to eliminate the costs for external services allocated to the "IS support" sub-item. This allows GRTgaz to save €1.5m per year on average. The auditor has recalculated the avoided cost, based on average cost per member of staff, and recommends an additional adjustment of €1.2m per annum on average.

In the "increase to network costs" sub-item, GRTgaz has submitted a projected increase of +20% per year in the volume of data to be managed by the IS, or an impact of €2.4m per year on average. The auditor considers that the projected increase in data volumes can be absorbed within the recurrent costs, and as a result recommends adjusting this increase.

CRE retains these adjustments.

No further adjustments are retained by CRE for the "operational support" item.

Therefore, the trajectory for the "operational support" item is the following:

GRTgaz - Operational support

GRTgaz, in €mcurrent	Actual 2015	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application		171	180	178	179	177
Adjustments retained by the CRE*		-4	-8	-16	-18	-12
Retained trajectory	**152**	**167**	**172**	**162**	**161**	**165**

* including an adjustment linked to the GRTgaz 2020 project of approximately €8m per year on average, detailed below.

Operating products

Operating products, excluding capitalised production, encompasses a number of income items mainly linked to connection and engineering works, which are billed to third parties, and other everyday management products.

GRTgaz forecasts a decrease in operating products (excluding capitalised production) of €3m, or -4.2%, between the actual 2015 results and 2017, after incorporating the restated 3R costs for 2015 in order to maintain a like-for-like basis. During the period 2017-2020, the products then increase by +0.9% per annum on average.

Works for reimbursable services (WRS)

The auditor recommends adjusting the projected trajectory of exceptional WRS to take account of the actual level in the ATRT5 period and not just the 2016 estimate, as GRTgaz has currently done. CRE retains this adjustment, which increases the WRS trajectory by approximately €7m per annum on average.

Other everyday management products

In its projected trajectory, GRTgaz has not incorporated actual income considered exceptional during the ATRT5 period from various everyday management products. The auditor recommends that these elements are not entirely passed on in each year of the ATRT6 period, but that a part at least is included in the trajectory. CRE retains this adjustment, which increases the trajectory of other everyday management products by approximately €3m per annum on average.

No further adjustments are retained by CRE for operating products.

Therefore, the retained trajectory for operating products, excluding capitalised production, is the following:

GRTgaz - Operating products, excluding capitalised production

GRTgaz, in €m$_{current}$	Actual 2015*	2017	2018	2019	2020	Average 17-20
Updated GRTgaz application		65	68	71	67	68
Adjustments retained by the CRE		11	9	8	11	10
Retained trajectory	**68**	**76**	**77**	**79**	**78**	**77**

* the actual 2015 results were restated for the 3R charges (by €15.7m) to maintain a like-for-like basis with the period 2017-2020.

GRTgaz 2020 project

Expenditure associated with the GRTgaz 2020 project is distributed among the various items of the tariff application.

The auditor has analysed the projected expenses linked to this project, to estimate the sums needed for new services and the relevance of their inclusion within the scope of the ATRT6 tariff. He recommends an adjustment of €22m on average per year.

CRE thinks it necessary the TSOs be involved in the energy transition, especially to plan the future of gas transmission systems. It welcomes GRTgaz's launch of the GRTgaz 2020 project, insofar as it allows future changes in the energy sector to be incorporated into activities led by the TSO over the ATRT6 period.

Nonetheless, it also believes, as does the auditor, that some of the subject areas covered by the GRTgaz 2020 project are normal and expected changes to the TSO's activity, and could wholly or partially be carried out as part of its current organisation. It also believes that a small portion of these services stray too far from GRTgaz's core business area, and consequently has not retained the costs associated with these in its trajectory for ATRT6. Finally, it holds that some of the new activities could be performed more efficiently by the TSO, and has revised the associated figures.

CRE retains an adjustment of €17m per year on average for the GRTgaz 2020 project (-32%) compared to the operator's request, consisting of:

- -€6m per year on average for the mean payroll per FTE recruited as part of the GRTgaz 2020 project, halfway between GRTgaz's suggestion and the auditor's recommendation;
- -€11m in other adjustments, which affect the operational support (-€8m) and industrial system (-€3m) items, incorporated in the sub-item tables in question.

CRE also believes that some areas of the GRTgaz 2020 project should fall under the scope of R&D, and must be subject to the R&D incentive regulations introduced by the ATRT6 tariff (section 1.3.3) in the same way as recurrent R&D expenses. These areas are:

- biomethane (2nd and 3rd generation);
- *Power to Gas;*
- support for efficient uses in industry (partial);
- leakage reduction (partial);
- H_2 transmission;
- direct support to research and innovation in green gas;
- de-optimisation costs linked to extrication of CRIGEN's R&D activities;
- data analysis.

The total trajectory subjected to the R&D incentive regulation is given in section 2.1.2.5.

The trajectory retained by CRE for the GRTgaz 2020 project is the following (excluding energy):

GRTgaz - Trajectory of operating costs for the GRTgaz 2020 project

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
GRTgaz application	41	59	54	52	51
Trajectory retained by the CRE	**28**	**46**	**34**	**31**	**35**
of which R&D	4	10	10	12	9

b) <u>TIGF</u>

The approach adopted by the auditor to analyse the net operating expenses levels of TIGF consisted of assessing the projected trajectories submitted by the operator for each of its cost items, as compared with the actual cost levels over the 2013-2015 period and in 2015 in particular.

<u>Production costs</u>

The "production costs" item includes routine technical costs (maintaining the network in working order - upkeep, measurements, technical studies, IS, etc.), costs linked to safety and the environment (network inspections and monitoring, sustainable development, etc.), storage costs, and operating costs for new projects.

TIGF has requested an increase of €1.7m to the "production costs" item, or +5.3% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +0.2% per annum on average.

<u>Routine technical costs - Industrial IS</u>

TIGF has highlighted its desire to adapt to the changing market in the information systems sector. The auditor recommends a downward adjustment of €0.1m per annum on average, or -5.1% compared to TIGF's application, for recurrent industrial IS costs, so as to recalibrate the projected expenses based on the 2013-2015 history without incorporating the 2016 estimate. CRE retains this adjustment.

<u>Safety and environment - R&I</u>

TIGF forecasts the implementation of a research and innovation (R&I) strategy, which did not exist at the start of the ATRT5 tariff but which was initiated at the end of 2015. CRE welcomes this step. The subject areas covered by the R&I strategy are detailed in section 2.1.1.2. For this, TIGF requests a budget of €2.4m per year on average for operating costs.

CRE has adjusted the trajectory requested by TIGF for R&I by €0.3m per year on average. Some of the projects in TIGF's programme, especially those scheduled to take place near the end of the ATRT6 period, are not sufficiently detailed.

No further adjustments are retained by CRE for the “production costs” item.

Therefore, the trajectory for the “production costs” item is the following:

TIGF - Production costs

TIGF, in €m$_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
TIGF application		33	33	33	33	33
Adjustments retained by the CRE		-0.2	-0.2	-0.5	-0.5	-0.4
Retained trajectory	**31**	**32**	**33**	**32**	**32**	**32**

Major revisions and repairs

The “major revisions and repairs” item includes costs associated with revisions and repairs.

TIGF has requested a decrease of €0.8m to the “major revisions and repairs” item, or -11.9% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +12.2% per annum on average.

Major upkeep

TIGF began to optimise the replacement programme for the preventive maintenance of its machines in 2013. Expenditure related to the “major upkeep” sub-item totalled €1.2m less than projected for the period 2013-2015.

Upkeep forecasts are stable for the ATRT6 period, except for the year 2020 with an increase of €2.2m compared to 2019. This is because TIGF is planning to carry out maintenance on two turbo-compressors that year. The auditor recommends 50% be hedged off the cost of these works, to account for the risk of the project running over into the following tariff period.

Given the lack of certainty regarding the schedule, CRE believes that the 50% reduction to the cost of these works as recommended by the auditor is relevant.

No further adjustments are retained by CRE for the “major revisions and repairs” item.

Therefore, the retained trajectory for the “major revisions and repairs” item is the following:

TIGF - Major revisions and repairs

TIGF, in €m$_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
TIGF application		6	6	7	9	7
Adjustment retained by the CRE		-	-	-	-1.1	-0.3
Retained trajectory	**7**	**6**	**6**	**7**	**8**	**7**

Staff and shared resources

The “staff and shared resources” item encompasses staffing costs, capitalised production, shared resources, and the repayment of running costs to TIGF Storage.

TIGF has requested an increase of €5.7m to the “staff and shared resources” item, or +10.1% between the actual 2015 figures and 2017. During the period 2017-2020, the costs would then increase by +2.8% per annum on average.

Shared resources

The supporting documents provided by TIGF did not explain all of the operator’s requested changes between the actual 2013-2015 figures and its application for the ATRT6 tariff in the following sub-items:

- management service agreement for TIGF Investment, which includes the costs of the TIGF Group's new governance structure;
- the new communication strategy.

The auditor therefore suggests a downward adjustment to the "shared resources" item, of around €4m per year on average. CRE retains this adjustment.

Repayment of running costs

As described in section 2.1.2.1, the breakdown between transport and storage activities was not taken into account by the auditor in his adjustments. The repayment by TIGF Transport to TIGF Storage must therefore be revised downward, by €1.5m per year on average.

No further adjustments are retained by CRE for the "staff and shared resources" item.

Therefore, the retained trajectory for the "staff and shared resources" item is the following:

TIGF - Staff and shared resources

TIGF, in $€m_{current}$	Actual 2015	2017	2018	2019	2020	Average 17-20
TIGF application		62	62	68	68	65
Adjustments retained by the CRE		-2.3	-2.4	-2.4	-2.1	-2.3
Retained trajectory	**57**	**60**	**60**	**65**	**66**	**63**

2.1.2.4 Summary

a) <u>GRTgaz</u>

The level of net operating expenses for GRTgaz as a result of the adjustments retained by CRE is as follows:

Summary of adjustments - Net operating expenses for GRTgaz

GRTgaz, in €$m_{current}$	Actual 2015*	2017	2018	2019	2020	Average 17-20
Net operating expenses - Updated GRTgaz application		**804**	**840**	**858**	**877**	**845**
Adjustments retained by the CRE						
Energy		-4	-7	-6	-9	-7
Industrial system		-2	-5	-3	-3	-3
Gas system, excluding energy		-2	-2	-3	-3	-3
Operational support		-2	-3	-4	-5	-4
Operating products *- of which service products* *- of which other products*		+11 *8* *3*	+9 *7* *3*	+8 *5* *3*	+11 *8* *3*	+10 *7* *3*
GRTgaz 2020 project		-12	-13	-20	-21	-17
Other		-0	-1	-2	-2	-1
Additional efficiency		-7	-14	-21	-28	-17
Net operating expenses retained by the CRE	**738**	**764**	**786**	**792**	**794**	**784**

* the actual 2015 results were restated for the 3R charges (by €15.7m) to maintain a like-for-like basis with the period 2017-2020.

To account for variations linked to inflation, the ATRT6 tariff indexes the trajectory of net operating expenses to the CPI, which equates to:

GRTgaz, in €$m_{current}$	2017	2018	2019	2020
Net operating expenses - Smoothed trajectory indexed to CPI	**764**	**CPI + 0.74%**		

b) TIGF

The level of net operating charges for TIGF as a result of the adjustments retained by CRE is as follows:

Summary of adjustments - Net operating expenses for TIGF

TIGF, in €m$_{current}$	Actual 2015*	2017	2018	2019	2020	Average 17-20
Net operating expenses - TIGF application	-	80	81	89	92	85
Adjustments retained by the CRE						
Energy	-	-1.4	-2.2	-3.4	-4.1	-2.8
Production costs	-	-0.2	-0.2	-0.5	-0.5	-0.4
Major modifications and repairs	-	-	-	-	-1.1	-0.3
Staff and shared resources		-2.3	-2.4	-2.4	-2.1	-2.3
Additional efficiency	-	-	-0.7	-1.4	-2.2	-1.1
Net operating expenses retained by the CRE	75	76	75	81	82	79

* the actual 2015 results were restated for the maintenance costs for delivery points and distribution connections (by €3.9m) to maintain a like-for-like basis with the period 2017-2020.

To account for variations linked to inflation, the ATRT6 tariff indexes the trajectory of net operating expenses to the CPI, which equates to:

TIGF, in €m$_{current}$	2017	2018	2019	2020
Net operating expenses - Smoothed trajectory indexed to CPI	76	CPI + 1.04%		

2.1.2.5 Trajectory of projected R&D expenses

The ATRT6 tariff introduces an incentive regulation mechanism for R&D expenses, described in section 1.3.3.

2.1.2.5.1 GRTgaz

The trajectory that will be subject to the R&D incentive regulation mechanism incorporates research and development expenditure linked to transmission system technology, as well as certain areas covered by the GRTgaz 2020 project.

Projected R&D expenses for GRTgaz

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
R&D “within ATRT5”	12	12	12	12	**12**
GRTgaz 2020 project	4	10	10	12	**9**
ATRT6 total	**16**	**22**	**22**	**24**	**21**

2.1.2.5.2 TIGF

The trajectory that will be subject to the incentive regulation mechanism is the same as the expenditure retained by CRE for TIGF's R&I programme. It covers the following main subject areas:

- integrity of facilities;
- energy efficiency;
- biomethane;
- biodiversity.

Projected R&D expenses for TIGF

TIGF, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
ATRT6	2.3	2.2	2.1	2.0	2.2

2.1.3 Normative capital charges

Normative capital charges (NCC) comprise the return on and depreciation of fixed capital. To calculate the capital charges to be covered by the tariffs, CRE retained the projected investment figures provided by GRTgaz and TIGF, after deducting their projections for certain projects that seem unlikely to reach completion (see section 2.1.3.5).

CRE applied the methods for calculating capital charges used when setting previous tariffs. It however amended its assessment of the weighted average cost of capital (WACC) for the natural gas transmission activity.

CRE relied in particular on the results of the critical analysis of the requests from GRTgaz and TIGF concerning the remuneration rate. As part of its public consultation of July 2016, CRE presented its preliminary analysis of the operators' rate of return application.

2.1.3.1 Rate of return on the RAB

For the ATRT6 tariff period, GRTgaz and TIGF submitted a WACC request of 6.5% (real, pre-tax), which is identical to the rate of return for the ATRT5 tariff.

During the public consultation of July 2016, CRE published of range of expected WACC values (4.75 - 5.5%). Among the contributors, some of the stakeholders claimed that a rate of return within such a range is overestimated, especially given current market conditions. Other stakeholders welcomed the decrease of the rate of return suggested by CRE compared to the rate used for the ATRT5 period. Gas infrastructure operators and their shareholders argued for stable rates of return, and for the distinction between gas distribution and gas transmission to be retained.

CRE has re-examined the various parameters used to calculate the WACC. Additionally, it has commissioned an external service provider to carry out a study with a view to auditing the capital return application submitted by GRTgaz and TIGF, based mainly on the updated results from the 2015 study assessing the rates of return of electricity and natural gas network operators in France, in order to establish the GRDF ATRD5 tariff.

For the ATRT6 tariff, CRE sets the value of 5.25% as the weighted average cost of capital (actual rate before tax) to provide a return on the TSOs' RAB, based on ranges of values for each of the parameters included in the WACC formula. The values used by CRE for each of these parameters are shown in the table below :

WACC parameters

Real risk-free rate*	1.6%
Debt spread	0.6%
Asset beta	0.45
Equity beta	0.75
Market risk premium	5.0%
Gearing (debt/(debt + equity))	50%
Corporation tax rate	34.43%
Tax deductibility of financial expenses	75%
Debt cost (real before tax)	2.4%
Equity cost (real before tax)	8.1%
WACC (real before tax)	**5.25%**

***i.e. assumed nominal risk-free rate of 2.7%**

In comparison to the values used to define the WACC for the ATRT5 tariff, the main modifications, in line with changes to the macro-economic and financial data, focus on :

- the risk-free rate – fixed at 1.6% – lower than the risk-free rate used in the ATRT5 tariff period (2.0%). This decrease is justified by the significant and long-lasting drop in interest rates compared to the levels seen when the previous tariff was set;
- the asset beta – fixed at 0.45 – lower than the value used for the ATRT5 tariff period (0.58). The retained value mainly takes into account market observations and asset betas for gas transport in Europe, as well as the uncertainty around the long-term prospects for gas;
- the tax deductibility for net financial expenses – fixed at 75% – according to the provisions of article 212a of the General Taxation Code which introduces a 75% cap (instead of the previous 100%) on the portion of net financial expenses that are deductible from the taxable revenue of companies whose total net financial expenses are greater than three million euros. This provision increases the operators' cost of debt.

2.1.3.2 Return on fixed assets under construction

In accordance with section 1.2.1.2.4, fixed assets under construction (AuC) are remunerated at the pre-tax nominal cost of debt, i.e. 3.7% under the ATRT6 tariff.

The method for calculating the AuC amount to be remunerated is explained in section 1.2.1.2.4.

2.1.3.3 Incorporating stranded costs to be covered

The costs to be covered by the tariff include coverage for stranded costs, in accordance with the conditions described in section 1.2.1.2.5.

As part of the ATRT6 tariff, CRE has decided to retain an annual amount of €3.25m for stranded costs to be covered by the GRTgaz tariff. TIGF has not forecast any stranded costs for the period 2017-2020.

2.1.3.4 Tariff adjustments

As per CRE proceedings of 28 October 2010[43] on gas transmission tariffs, the GRTgaz and TIGF capital charges are adjusted for the ATRT6 tariff period, with the amounts shown in the table below.

With regards to GRTgaz, the adjustment is linked to safety and compliance costs (relating to the 2006 multi-fluid decree) stated in the accounts as investments by the operator, whereas they were covered as operating costs for the period 2009-2010 when establishing the ATRT4 tariff trajectory. CRE has corrected the corresponding GRTgaz capital charges insofar as, in terms of the tariff, the same cost was counted as both an operating cost (in the projected ATRT4 tariff trajectory) and a capital charges (via the clawback account). During the ATRT5 tariff period, this adjustment led CRE to deduct an average of €12m per year from the NCC to be covered.

[43] http://www.cre.fr/documents/deliberations/proposition/tarifs-d-utilisation-des-reseaux-de-transport-de-gaz-naturel

With regards to TIGF, the adjustment is linked to the conclusion of the audit commissioned by CRE into the Guyenne branch project, due to which CRE suggested deducting €3m from TIGF's regulated asset base. During the ATRT5 tariff period, this restatement led CRE to deduct approximately €0.3m per year from the NCC to be covered.

The ATRT6 tariff projects for these adjustments to continue, by correcting the amounts detailed below from the capital charges trajectories for GRTgaz and TIGF to be covered during the period 2017-2020 :

NCC restatements for GRTgaz and TIGF tariffs

In €m$_{current}$	Average 2013-16	2017	2018	2019	2020	Average 17-20
NCC corrections for GRTgaz	-12.2	-4.8	-4.7	-4.5	-2.2	-4.0
NCC corrections for TIGF	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3

2.1.3.5 GRTgaz and TIGF investment programmes

Calculating the RAB and capital expenditure for the ATRT6 tariff incorporates the investment forecasts provided by the operators and, where necessary, revised by the CRE.

Any discrepancies between the investment forecasts and actual expenditure are covered by the clawback account mechanism, subject to any audit results and the effects of incentive mechanisms for controlling the costs of investment programmes and "non-network" costs.

2.1.3.5.1 GRTgaz investment programme

The ATRT6 period is marked by a drop in investment expenditure by GRTgaz, with average expenses of €544m per year during this period, whereas they were around €660m per year during the ATRT5 period.

Over the next tariff period GRTgaz forecasts an investment peak in 2017, associated with the Val de Saône and Gascogne-Midi construction projects, which are necessary for the creation of the single marketplace. The trajectory for network development investments subsequently decreases through to 2020.

CRE has restated the expenditure forecast supplied by GRTgaz, by removing projected expenses linked to certain projects that CRE believes too unlikely to reach completion to warrant incorporation into the trajectory at this stage. If necessary, these projects will be subject to CRE approval as part of the annual TSO investment budget approval, and any discrepancies with the projected trajectory retained will be wholly covered by the clawback account mechanism.

As a result, CRE shall retain a restated trajectory for efficiency projects deemed likely by GRTgaz, as well as for some uncertain projects planned as part of the GRTgaz 2020 project.

GRTgaz - Investment programme

GRTgaz, in €m$_{current}$ (gross subsidies)	2017	2018	2019	2020	Average 17-20
GRTgaz application	762.0	601.6	562.9	651.0	644.2
of which "base"	*687.0*	*496.1*	*466.1*	*549.2*	*549.6*
of which "GRTgaz 2020"	*75.0*	*105.5*	*96.8*	*101.8*	*94.6*
Adjustments	-121.6	-27.2	-56.1	-196.2	-100.3
of which "base"	-89.5	-15.1	-46.4	-185.1	-84.0
of which "GRTgaz 2020"	-32.1	-12.1	-9.7	-11.1	-16.3
Trajectory retained by the CRE	640.3	574.0	506.7	454.9	544.0
of which "base"	*597.5*	*481.0*	*419.7*	*364.1*	*465.6*
of which "GRTgaz 2020"	*42.9*	*93.4*	*87.1*	*90.7*	*78.3*

In addition, the ATRT6 tariff introduces a specific regulation mechanism for "non-network" investments, described in section 1.3.1.2.2. The investment trajectory for these assets is described below:

GRTgaz, in €m$_{current}$ (gross subsidies)	2017	2018	2019	2020	Average 17-20
"Non-network" investments	77.8	78.1	80.0	77.5	78.4
Property	*17.6*	*9.0*	*9.0*	*9.0*	*11.2*
Information systems	*49.1*	*59.4*	*61.9*	*59.4*	*57.5*
Mobile assets (including vehicles)	*11.1*	*9.7*	*9.0*	*9.1*	*9.7*

2.1.3.5.2 TIGF investment programme

Primarily linked to the Gascogne-Midi project at the start of the period, TIGF's investment expenses also include the reinforcement of the AGU compression station. TIGF also forecasts expenditure linked to the STEP project (the first phase of MidCat)[44] for a total of €91m during the ATRT6 period.

CRE has restated the expenditure forecast supplied by TIGF, by removing projected expenses linked to certain projects that CRE believes too unlikely to reach completion to warrant incorporation into the trajectory at this stage. If necessary, these projects will be subject to CRE approval as part of the annual TSO investment budget approval, and any discrepancies with the projected trajectory retained will be wholly covered by the clawback account mechanism.

As a result, CRE shall retain a restated trajectory for the MidCat project, as well as for some uncertain projects planned as part of the R&I programme.

CRE retains the costs associated with conducting a study for the STEP project in collaboration with Enagas. This study was requested by the European Commission for a budget of €8m for TIGF, subsidised 50%. These costs will be incorporated into the fixed assets under construction for as long as the STEP project is being studied. CRE will examine the coverage of these stranded costs should the project fail to go ahead.

TIGF - Investment programme

TIGF, in €m$_{current}$ (gross subsidies)	2017	2018	2019	2020	Average 17-20
TIGF application	108.3	150.3	112.1	135.0	126.4
of which non R&I	*106.5*	*148.5*	*110.4*	*133.2*	*124.7*
of which R&I	*1.8*	*1.8*	*1.7*	*1.8*	*1.8*
Adjustments	-0.6	-3.5	-13.2	-73.4	-22.6
of which non R&I	*-0.1**	*-2.5**	*-11.7*	*-71.8*	*-21.5*
of which R&I	*-0.5*	*-1.0*	*-1.5*	*-1.6*	*-1.1*
Total	107.7	146.9	98.9	61.6	103.8
of which non R&I	*106.5*	*146.1*	*98.7*	*61.4*	*103.1*
of which R&I	*1.3*	*0.8*	*0.2*	*0.2*	*0.6*

** updated with the latest known trajectory*

In addition, the ATRT6 tariff introduces a specific regulation mechanism for "non-network" investments, described in section 1.3.1.2.2. The investment trajectory for these assets is described below:

[44] STEP is a direct interconnection project with Spain that, on the French side, is exclusively comprised of a linear structure linking Le Perthus to Barbaira. STEP is the first phase of the MidCat project, which aims to establish interruptible capacities between Spain and France. It has a budget of €320m.

TIGF, in €m$_{current}$ (gross subsidies)	2017	2018	2019	2020	Average 17-20
"Non-network" expenses	16.4	17.0	17.1	13.6	16.0
Property	*2.5*	*3.5*	*2.8*	*1.4*	*2.5*
Information systems	*14.0*	*13.5*	*14.3*	*12.2*	*13.5*
Mobile assets (including vehicles)	-	-	-	-	-

2.1.3.6 Projected capital charges trajectories for the period 2017-2020

2.1.3.6.1 Projected capital charges trajectory for GRTgaz

The table below shows the projected trajectory for GRTgaz from 2017 to 2020 in terms of RAB and fixed assets under construction (AuC):

Regulated asset base (RAB) and fixed assets under construction (AuC)

GRTgaz, in €m$_{current}$	Average 13-16	2017	2018	2019	2020	Average 17-20
RAB at 01/01/yyyy	7,453.6	8,281.2	8,270.3	8,863.8	8,941.6	8,589.2
Assets commissioned*		367.1	980.1	488.9	506.8	585.7
Depreciation		-461.8	-470.7	-500.6	-503.4	-484.1
Revaluation		83.8	84.1	89.5	90.4	86.9
RAB at 31/12/yyyy		8,270.3	8,863.8	8,941.6	9,035.3	8,777.8
Fixed assets under construction (AuC)	1,034.6	705.0	887.7	402.0	384.5	594.8

* Investments entered in the RAB

The table below shows the projected trajectory for GRTgaz from 2017 to 2020 in terms of normative capital charges (NCC):

GRTgaz, in €m$_{current}$	Average 13-16	2017	2018	2019	2020	Average 17-20
Depreciation of assets in service	400.2	461.8	470.7	500.6	503.4	484.1
Return on assets in service	532.2	503.1	500.8	547.8	546.2	524.5
Return on AuC	47.6	26.1	32.8	14.9	14.2	22.0
Return on subsidies	1.4	4.0	4.0	6.0	5.9	5.0
Coverage of stranded costs	2.0	3.3	3.3	3.3	3.3	3.3
Tariff adjustment	-12.2	-4.8	-4.7	-4.5	-2.2	-4.0
Total normative capital charges *of which "non-network" NCC*	**971.1**	**993.4** *93.9*	**1,006.9** *98.3*	**1,068.1** *104.1*	**1,070.8** *101.1*	**1,034.8** *99.4*

2.1.3.6.2 Projected capital expenditure trajectory for TIGF

The table below shows the projected trajectory for TIGF from 2017 to 2020 in terms of RAB and fixed assets under construction (AuC):

Regulated asset base (RAB) and fixed assets under construction (AuC)

TIGF, in €m$_{current}$	Average 13-16	2017	2018	2019	2020	Average 17-20
RAB at 01/01/yyyy	1,199.2	1,338.4	1,353.4	1,496.1	1,560.0	1,437.0
Assets commissioned*		69.7	199.7	123.5	64.2	114.3
Depreciation		-68.0	-71.9	-75.1	-78.4	-73.4
Revaluation		13.4	14.8	15.4	15.5	14.8
RAB at 31/12/yyyy		1,353.4	1,496.1	1,560.0	1,561.1	1,492.7
Fixed assets under construction (AuC)	119.5	107.8	142.8	65.9	22.6	84.8

* Investments entered in the RAB

The table below shows the projected trajectory for TIGF from 2017 to 2020 in terms of normative capital charges (NCC):

TIGF, in €m$_{current}$	Average 13-16	2017	2018	2019	2020	Average 17-20
Depreciation of assets in service	58.7	68.0	71.9	75.1	78.4	73.4
Return on assets in service	90.3	85.8	86.5	96.6	99.9	92.2
Return on fixed assets under construction	5.5	4.0	5.3	2.4	0.8	3.1
Return on subsidies	0.8	1.1	1.5	1.5	1.5	1.4
Coverage of stranded costs	-	-	-	-	-	-
Tariff restatement	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Total normative capital charges	**155.0**	**158.7**	**164.9**	**175.3**	**180.4**	**169.8**
of which “non-network” NCC		*18.9*	*21.7*	*20.7*	*22.4*	*20.9*

2.1.3.6.3 Trajectory of "non-network" capital charges for GRTgaz and TIGF

The table below details the projected RAB, AuC and NCC trajectory for GRTgaz's "non-network" assets from 2017 to 2020, which are subject to specific regulations defined in section 1.3.1.2.2:

GRTgaz, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
RAB at 01/01/yyyy	356.7	354.4	361.3	371.5	361.0
Depreciation of assets in service	73.1	77.4	82.9	79.8	78.3
Return on assets in service	19.0	18.8	19.1	19.7	19.1
Fixed assets under construction (AuC)	47.1	57.7	56.2	45.5	51.6
Return on fixed assets under construction	1.7	2.1	2.1	1.7	1.9
Total "non-network" NCC	**93.9**	**98.3**	**104.1**	**101.1**	**99.4**

The table below details the projected RAB, AuC and SCE trajectory for TIGF's "non-network" assets from 2017 to 2020, which are subject to specific regulations defined in section 1.3.1.2.2:

TIGF, in €m$_{current}$	2017	2018	2019	2020	Average 17-20
RAB at 01/01/yyyy	72.9	79.5	80.3	82.2	78.7
Depreciation of assets in service	14.6	17.2	16.1	17.9	16.4
Return on assets in service	3.9	4.2	4.2	4.3	4.2
Fixed assets under construction (AuC)	12.4	8.7	8.6	6.8	9.1
Return on fixed assets under construction	0.5	0.3	0.3	0.3	0.3
Total "non-network" NCC	**18.9**	**21.7**	**20.7**	**22.4**	**20.9**

2.1.4 Inclusion of the ATRT5 tariff revenues and expenses clawback account

The clawback account balance on 31 December 2016 will be cleared over a period of four years. It is updated to the 2.7% interest rate, which corresponds to the nominal risk-free rate (see section 2.1.3.1).

2.1.4.1 GRTgaz

In its March 2016 tariff file, GRTgaz estimated the clawback account balance on 31 December 2016 at €120.3m after deducting the charges to be covered. In its July 2016 tariff file, GRTgaz re-evaluated the clawback account balance on 31 December 2016 to be €109.3m after deducting the charges to be covered.

The clawback account balance on 31 December 2016 used by CRE to calculate GRTgaz's allowed revenue is €104.6m, after deducting the charges to be covered. This figure is taken from the updated outstanding balances of previous clawback accounts, the updated difference between the actual 2015 clawback account balance and the estimated 2015 clawback account balance when updating the ATRT5 tariff on 1 April 2016, as well as the updated estimated clawback account balance for 2016. The discrepancy with the GRTgaz application stems from corrections made to the assumptions for capital expenditure and estimated income from capacity subscriptions for 2016.

GRTgaz - clawback account on 31 December 2016

GRTgaz	Amount in €m
Outstanding balance from previous clawback accounts	**-55.9**
Difference between estimated 2015 clawback account balance on 1 April 2016 and actual 2015 clawback account balance	**-0.3**
Estimated discrepancies for costs and products in 2016	**-48.3**
of which transmission revenue covered 100%	*15.8*
of which transmission revenue covered 50%	*1.6*
of which CCGT and CT connection revenue	*14.5*
of which normative capital charges	*-94.8*
of which energy costs	*11.5*
of which inter-operator contract	*-1.4*
of which OPEX deviation due to inflation	*-0.5*
of which service quality	*0.6*
of which coverage for delayed commissioning of the Dunkirk LNG terminal	*4.4*
Clawback account on 31 December 2016	**-104.6**

The total clawback account balance on 31 December 2016 will be cleared in four equal instalments of -€27.9m over the ATRT6 period, deducted from the allowed revenue. The total including discrepancies for the year 2016 is provisional: the final value will be incorporated into the clawback account when the tariff is updated on 1 April 2018.

2.1.4.2 TIGF

In its May 2016 tariff file, GRTgaz estimated the clawback account balance on 31 December 2016 at €5.7m, which are added to the charges to be covered. In its application, TIGF included a retroactive coverage of the tariff difference for the ATRT5 period, which it assesses at an impact of €12.9m. It proposes incorporating this sum into the clawback account for 2016.

The clawback account balance on 31 December 2016 used by CRE to calculate TIGF's allowed revenue is €3.4m, after deducting the charges to be covered. This figure is taken from the updated outstanding balances of previous clawback accounts, the updated difference between the actual 2015 clawback account balance and the estimated 2015 clawback account balance when updating the ATRT5 tariff on 1st April 2016, as well as the updated estimated clawback account balance for 2016. The discrepancy with the TIGF application firstly stems from the non-inclusion of the request to recover the tariff difference for the ATRT5 period, and secondly from corrections made to the assumptions for capital expenditure and estimated income from capacity subscriptions for 2016.

TIGF - Clawback account on 31 December 2016

TIGF	Amount in €m
Outstanding balance from previous clawback accounts	**-5.5**
Difference between estimated 2015 clawback account balance on 1 April 2016 and actual 2015 clawback account balance	**-0.3**
Estimated discrepancies for costs and products in 2016	**2.4**
of which transmission revenue covered 100%	*4.3*
of which transmission revenue covered 50%	*-*
of which CCGT and CT connection revenue	*-*
of which normative capital charges	*-5.0*
of which energy costs	*0.9*
of which inter-operator contract	*1.7*
of which OPEX deviation due to inflation	*-*
of which service quality	*0.5*
Clawback account on 31 December 2016	**-3.4**

The total clawback account balance on 31 December 2016 will be cleared in four equal instalments of €0.9m over the ATRT6 period, deducted from the allowed revenue. The total including discrepancies for the year 2016 is provisional: the final value will be incorporated into the clawback account when the tariff is updated on 1st April 2018.

2.1.5 Inter-operator compensation

The compensation from TIGF to GRTgaz as part of the income received at the Pirineos PIR exit point is determined based on the sum of the tariff charges at the North-South link carried forward to the Pirineos PIR exit charge once the single marketplace has been created, applied to the projected subscriptions at this exit point. This is a source of income for GRTgaz and a cost for TIGF. These sums will be 100% covered by the clawback account mechanism, so that the subscriptions made at the Pirineos PIR are included in the final calculation.

Inter-operator compensation

In current €m	2017	2018	2019	2020	Average 17-20
Projected subscriptions at the Pirineos PIR exit point (GWh/d/yr)	149	149	149	149	149
Of which firm annual/seasonal	148	148	148	148	148
Of which firm quarterly	1	1	1	1	1
Of which firm monthly	1	1	1	1	1
Amount carried forward to the Pirineos PIR exit charge (€/MWh)	-	117.9	119.1	120.3	89.3
GRTgaz - Income received (current €m)	-	**-3**	**-18**	**-18**	**-10**
TIGF - Charges paid (current €m)	-	**3**	**18**	**18**	**10**

2.1.6 Allowed revenue for tariff period 2017-2020

The allowed revenues for GRTgaz and TIGF for the period 2017-2020 are defined as the sum of the following items:

- the net operating expenses (see section 2.1.2);
- capital expenditure (see section 2.1.3);

- the financial flow of inter-operator compensation, from TIGF to GRTgaz, as part of carrying forward some of the income previously received at the North-South link at the Pirineos exit (see section 2.1.5);
- clearance of the clawback account balance calculated on 31 December 2016 (see section 2.1.4).

2.1.6.1 Allowed GRTgaz revenue for tariff period 2017-2020

The allowed revenue for GRTgaz is broken down as follows:

GRTgaz - Projected allowed revenue

GRTgaz, in €m$_{current}$	2016	2017	2018	2019	2020	Average 17-20
Net operating expenses *	719	764	777	791	804	**784**
Normative capital charges	1,142	993	1,007	1,068	1,071	**1,035**
Clearance of the balance in the revenues and expenses clawback account (remainder from previous clawback accounts + 2015 balance + 2016 estimate)	-20	-28	-28	-28	-28	**-28**
Allowed revenue excluding repayments *Change*	**1842**	**1729** *-6.1%*	**1756** *+1.5%*	**1831** *+4.2%*	**1847** *+0.9%*	**1791** ***-1.1%***
Inter-operator repayments	-	-	-3	-18	-18	-10
Allowed revenue *Change*	**1,842**	**1,729** *-6.1%*	**1,753** *+1.4%*	**1,813** *+3.4%*	**1,829** *+0.9%*	**1,781** ***-1.3%***

* in this table, the net operating cost trajectory has been smoothed

2.1.6.2 Allowed TIGF revenue for tariff period 2017-2020

The allowed revenue for TIGF is broken down as follows:

TIGF - Projected allowed revenue

TIGF, in €m$_{current}$	2016	2017	2018	2019	2020	Average 17-20
Net operating expenses *	71	76	78	79	81	**79**
Normative capital charges	177	159	165	175	180	**170**
Clearance of the balance in the revenues and expenses clawback account (remainder from previous clawback accounts + 2015 balance + 2016 estimate)	-1.9	-0.9	-0.9	-0.9	-0.9	**-0.9**
Allowed revenue excluding repayments *Change*	**246**	**234** *-5.0%*	**242** *+3.3%*	**254** *+4.9%*	**261** *+2.7%*	**248** ***+0.2%***
Inter-operator compensation	-	-	3	18	18	**10**
Allowed revenue *Change*	**246**	**234** *-5.0%*	**245** *+4.6%*	**272** *+11%*	**279** *+2.6%*	**257** ***+1.7%***

* in this table, the net operating cost trajectory has been smoothed

2.2 Assumed capacity subscriptions for 2017-2020

2.2.1 Changes observed in the period covered by the ATRT5 tariff

2.2.1.1 Change in GRTgaz subscriptions

Over the 2013-2016 period, ATRT5 tariff forecasted an average increase in capacity subscriptions on the transmission system of +1.2% per year, not counting the repercussions of the Midi PIR disappearing when the TRS was created.

In reality, the increase observed over the period was +0.1% per year on average. GRTgaz claims this discrepancy is mainly due to:

- the delay in starting up the Dunkirk LNG terminal;
- decreasing subscriptions at the transport storage interface points;
- a larger than anticipated drop in subscriptions on the regional network: there was a dramatic reduction in use by industrial clients. Similarly, the tariff forecast an increase in CCGT subscriptions, whereas in fact these fell slightly;
- the slight decrease in exits to Switzerland, whereas the tariff had predicted an increase;
- the drop in revenues from the North-South link and JTS and Market Coupling products, again where the tariff had forecast an increase.

2.2.1.2 Change in TIGF subscriptions

Over the 2013-2016 period, the ATRT5 tariff forecast an average increase in capacity subscriptions on the transmission system of +2.5% per year.

In reality, the increase observed over the period was +2.3% per year on average. TIGF claims this discrepancy is mainly due to:

- lower subscriptions at the Pirineos PIR exit point than forecast by the tariff;
- increased subscriptions at the transport storage interface points during the period, due to changes in storage options;
- a drop in subscriptions at delivery points on the regional network from 2015.

2.2.2 Trajectories retained for the ATRT6 tariff

GRTgaz and TIGF have established projected subscription trajectories for the ATRT6 period. These incorporate capacity subscriptions already in their portfolios, as well as their predictions of how natural gas consumption will change up until 2020 and of new capacity subscriptions at the various network points during the ATRT6 period. CRE has analysed the trajectories submitted by the TSOs and proceeded to adjust those it deemed necessary, which are set out below.

2.2.2.1 Trajectory for GRTgaz capacity subscriptions

GRTgaz has provided two trajectories in its tariff application: a “benchmark” scenario and an “optimistic” scenario. The predicted subscriptions put forward by GRTgaz for the ATRT6 period are detailed below:

- In the “benchmark” scenario:

GRTgaz, subscription forecasts (GWh/d)	2017	2018	2019	2020	Average 16-20
Change in main network	-2.2%	-2.4%	-7.7%	-2.1%	**-3.3%**
Change in regional network	-1.5%	-1.3%	-2.2%	-1.5%	**-1.6%**
Total subscription change	-1.8%	-1.8%	-4.9%	-1.8%	**-2.4%**

- In the “optimistic” scenario:

GRTgaz, subscription forecasts (GWh/d)	2017	2018	2019	2020	Average 16-20
Change in main network	-1.4%	-1.7%	-7.5%	-0.4%	**-2.6%**
Change in regional network	-1.2%	-0.8%	-1.3%	+0.3%	**-1.0%**
Total subscription change	-1.3%	-1.3%	-4.4%	0.0%	**-1.8%**

The substantial drop in subscriptions on the main network between 2018 and 2019 is linked to the disappearance of the North-South link once the single marketplace has been created.

- Main network

The subscriptions retained by CRE for the main network for the ATRT6 tariff match those given in GRTgaz’s “optimistic” scenario, which better fits the observed past trends and benefits offered by the GRTgaz 2020 project, with the exception of:

- interruptible and returnable subscriptions at the Dunkerque PIR: GRTgaz’s “optimistic” scenario has included subscription projections for interruptible and returnable capacities. At present, these forecasts are inconsistent with the changes seen over the past few months (only firm annual subscription projections are retained for this PIR);
- exits to the regional network, which must be consistent with the regional network subscription forecasts, given below.

- Regional network

On the regional network, CRE has retained the forecasts from the “optimistic” scenario, with the exception of:

- industrial subscriptions and subscriptions at the PITDs: CRE has retained the benchmark trajectories from the ten-year development plan published by the TSOs in late 2016. These figures fall in between the two scenarios submitted by GRTgaz in its tariff application;
- CCGT subscriptions: given the resurgence of CCGT activity since the end of 2015, and the entry into service of the Bouchain plant, CRE has not retained the prediction that the two plants will be mothballed, and has instead used the level of subscriptions logged in 2016. As suggested by GRTgaz, it has retained the prediction that the Landivisiau plant will enter into service in early 2020.

As a result, the projected subscription trajectory retained for the ATRT6 tariff is the following:

GRTgaz, subscription forecasts (GWh/d)	2017	2018	2019	2020	Average 16-20
Change in main network (excluding repercussions of disappearing of the N-S link)[45]	-1.4% (-1.4%)	-1.6% (-0.6%)	-7.3% (-0.7%)	-0.6% (-0.6%)	**-2.6% (-0.9%)**
Change in regional network	-1.2%	-0.6%	-0.7%	-0.1%	**-0.8%**
Total subscription change (excluding repercussions of disappearing of the N-S link)[41]	-1.3% (-1.3%)	-1.1% (-0.6%)	-3.9% (-0.7%)	-0.4% (-0.3%)	**-1.7% (-0.9%)**

2.2.2.2 Trajectory for TIGF capacity subscriptions

The predicted subscriptions put forward by TIGF for the ATRT6 period are detailed below:

TIGF, subscription forecasts (GWh/d)	2017	2018	2019	2020	Average 16-20
Change in main network	-0.1%	-0.1%	0.0%	0.0%	**-0.1%**
Change in regional network	-2.9%	0.0%	0.0%	0.0%	**-1.1%**
Total subscription change	-1.3%	-0.1%	0.0%	0.0%	**-0.5%**

- Main network

TIGF projects a slight decrease in subscriptions at the Pirineos PIR exit point in 2017 and 2018 and does not foresee any additional subscriptions, compared to 2016. It does however forecast consistent subscriptions at transport storage interface points between 2017 and 2020.

- Regional network

For 2017, TIGF believes that subscriptions on the regional network will be 2.9% lower than the forecasts retained by CRE for 2016 when the ATRT5 tariff was updated on 1st April 2016. The forecasts used when the tariff was updated were not met. TIGF suggests lowering the figure to match the actual subscriptions for the months from February 2015 to January 2016. This level will remain the same between 2017 and 2020.

CRE shall retain, for the most part, the projections put forward by TIGF, which it believes to be reasonable. To take into account the improved market liquidity once the single marketplace has been established, CRE has slightly revised TIGF's projections upwards for PEG exchanges between 2017 and 2020, in line with the forecasts retained for GRTgaz.

2.3 Tariff changes on 1st April 2017 and projected trajectory for the ATRT6 tariff for the period 2018-2020

2.3.1 Tariff change trajectory for GRTgaz

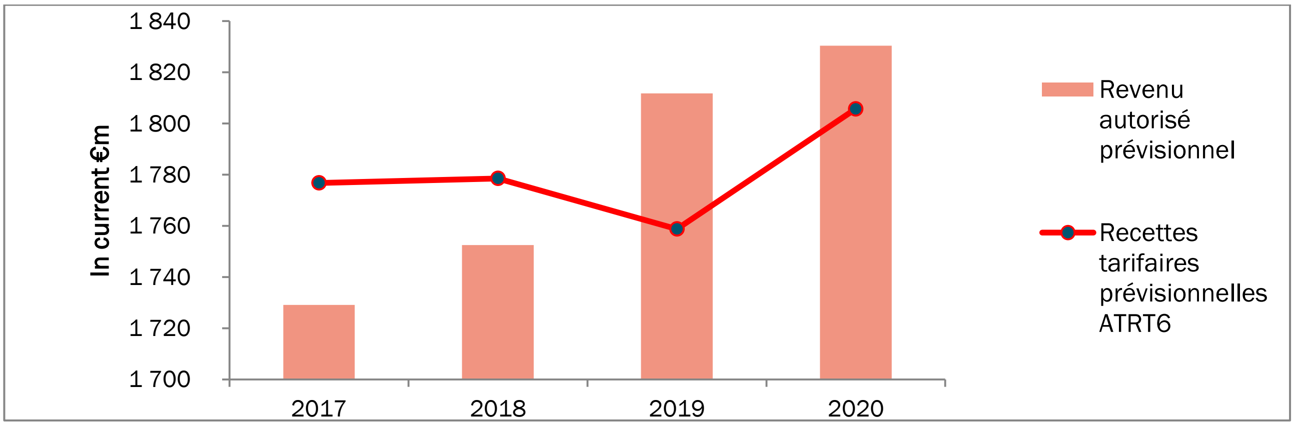
The tariff schedule applicable on 1st April 2017 is defined in part 3 of these proceedings. It equates to an average decrease of 3.1% in the unit tariff (-4.3% after restating the transferred 3R costs) compared to the current tariff schedule, excluding structural effects and inter-operator compensation.

Not counting any parameter changes incorporated into the annual updates, the GRTgaz tariff schedule will change by -0.4% per annum on average (-0.8% per annum after the transferred 3R costs are restated) during the ATRT6 period, excluding structural effects and inter-operator compensation.

The tariff changes on 1st April 2017, as well as annual changes to the tariff schedule for years 2018 to 2020, are calculated so that the total projected income from applying the ATRT6 tariff schedule to the capacity subscription forecasts is equal to the total allowed revenue for the period, based on the updated 2017-2020 figures.

[45] The change is restated with the disappearance of the North-South link and the Market Coupling and JTS products

Allowed revenue and projected tariff income



Given the balance between income and allowed revenue for the period 2017-2020 and annual changes to the tariff schedule, there may be annual differences between the income and allowed revenue figures. The updated sum of these annual differences for the period is equal 0.

As such, the projected allowed revenue and projected income for the ATRT6 tariff period are as follows:

Allowed revenue and projected tariff income

GRTgaz, in $€m_{current}$	2017	2018	2019	2020	Net updated value
Projected allowed revenue	1,729	1,753	1,813	1,829	6,664
Projected tariff income used to calculate annual tariff changes (excluding clearance of the clawback account balance)	1,777	1,780	1,759	1,805	6,664
Annual difference between projected income and projected allowed revenue	-48	-26	54	24	0

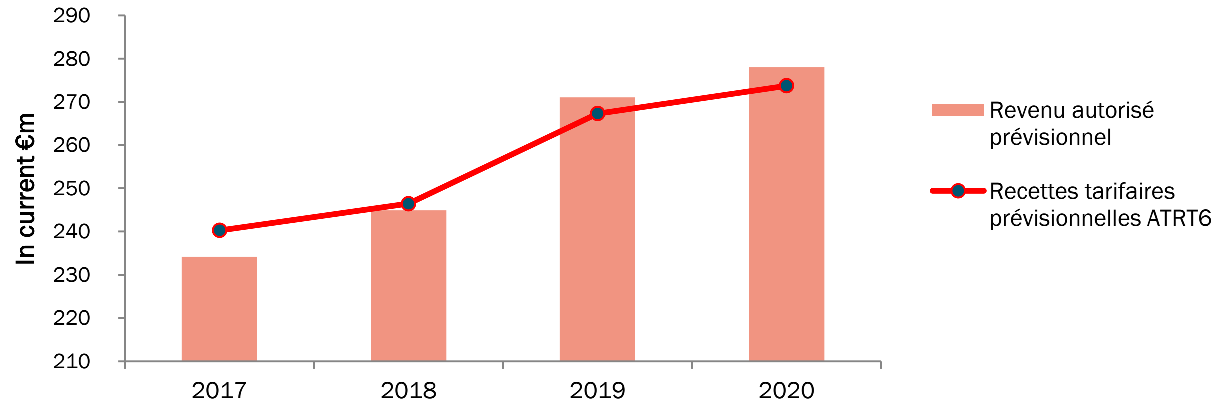
2.3.2 Tariff change trajectory for TIGF

The tariff schedule applicable on 1st April 2017 is defined in part 3 of these proceedings. It equates to an average decrease of 2.2% in the unit tariff (-4.3% after restating the transferred maintenance costs for delivery points and distribution connections) compared to the current tariff schedule, excluding structural effects and inter-operator compensation.

Not counting any parameter changes incorporated into the annual updates, the TIGF tariff schedule will change by +0.8% per annum on average (+0.1% per annum after the transferred maintenance costs are restated) during the ATRT6 period, excluding structural effects and inter-operator compensation.

The tariff changes on 1st April 2017, as well as annual changes to the tariff schedule for years 2018 to 2020, are calculated so that the total projected income from applying the ATRT6 tariff schedule to the capacity subscription forecasts is equal to the total allowed revenue for the period, based on the updated 2017-2020 figures.

Allowed revenue and projected tariff income



Given the balance between income and allowed revenue for the period 2017-2020 and annual changes to the tariff schedule, there may be annual differences between the income and allowed revenue figures. The updated sum of these annual differences for the period is equal to 0.

As such, the projected allowed revenue and projected income for the ATRT6 tariff period are as follows:

Allowed revenue and projected tariff income

TIGF, in €m$_{current}$	2017	2018	2019	2020	Net updated value
Projected allowed revenue	234	245	272	279	961
Projected tariff income used to calculate annual tariff changes (excluding clearance of the clawback account balance)	239	246	268	276	961
Annual difference between projected income and projected allowed revenue	-5	-1	4	3	0

3. TARIFF FOR THE USE GRTGAZ AND TIGF NATURAL GAS TRANSMISSION NETWORKS, APPLICABLE FROM 1 APRIL 2017

3.1 Tariff rules

3.1.1 Definitions

Network Interconnection Point (PIR):

Physical or notional interconnection point between main transmission systems of two transmission system operators (TSOs).

Regional Network Interconnection Point (PIRR):

Physical or notional interconnection point between a regional transmission system and a foreign operator network.

LNG Terminal Transmission Interface Point (PITTM):

Physical or notional interconnection point between a transmission system and one or more LNG terminals.

Transport Storage Interface Point (PITS):

Physical or notional interface point between a transmission system and a storage group.

Transport/Production Interface Point (PITP):

Physical or notional interface point between a transmission system and a gas or biomethane gas production facility.

Transport Distribution Interface Point (PITD):

Physical or notional interface point between a transmission system and a public distribution system.

TCE: capacity charge for entry to the main network, applicable to the daily capacity subscription at points of entry to the main network from a PIR or a PITTM.

TCES: capacity charge for entry to the main network from storage, applicable to the daily capacity subscription for entry to the main network from a PITS.

TCST: capacity charge for exit at the transmission system interconnection points, applicable to the daily capacity subscription for exit to a network interconnection point (PIR).

TCS: capacity charge for exit from the main network, applicable to the daily capacity subscription for exit from the main network, except to a PITS or a PIR.

TCSS: capacity charge for exit from the main network to storage, applicable to the daily capacity subscription for exit from the main network to a PITS.

TP: proximity charge, applicable to quantities of gas injected at a point of entry to the transmission system and exiting immediately within the vicinity of this point.

TCLZ: capacity connection charge, applicable to the daily capacity subscription for connection between balancing zones of the main network of the same TSO.

TCR: transmission capacity charge in the regional network, applicable to the daily capacity subscription for transmission in the regional network.

TCL: delivery capacity charge, applicable to the daily capacity subscription for delivery to a delivery point.

Firm capacity:

Gas transmission capacity, guaranteed under contract by the operator as uninterruptible.

Climatic firm capacity:

Gas transmission capacity, guaranteed under contract by the TSO as uninterruptible, depending on domestic consumption. This definition mainly applies to entry and exit capacities at the PITS.

Overhaul capacity:

Capacity allowing the shipper to make nominations in the opposite direction to the dominant direction of gas flow when the gas flow can only run in one direction. It may only be used, on a given day, if the global flow resulting from all nominations from shippers is in the dominant direction of the flow.

Interruptible capacity:

Gas transmission capacity that may be interrupted by the TSO according to the conditions stipulated in the gas transmission system supply agreement.

Returnable capacity:

Firm capacity, which the shipper agrees to return to the TSO at any time on request.

Shipper:

Individual or legal entity that enters into a transmission contract with a TSO on the gas transmission system. The shipper is, depending on the case, the eligible customer, the supplier or their representative.

3.1.2 Capacity subscription

3.1.2.1 PIR capacity subscription at auctions

The daily transmission capacities at network interconnection points (PIRs) at Taisnières B, Taisnières H, Obergailbach, Oltingue, Pirineos and Alveringem can be subscribed at auctions via the PRISMA capacity marketing platform. These capacities are marketed according to the terms laid out by EU regulation no. 984/2013, establishing a network code on capacity allocation mechanisms in gas transmissions systems known as the “CAM network code”. The detailed auction procedures and products on offer are published by GRTgaz and TIGF on their respective websites or the PRISMA auction platform.

Examples of available products are firm, interruptible and backhaul daily transmission capacities for annual, quarterly, monthly, daily and intra-day durations.

The auction reserve price is the same as the price fixed by the present tariff.

Contractualisation and billing for the network interconnection points (PIRs) at Taisnières B, Taisnières H, Obergailbach, Oltingue and Alveringem are carried out by GRTgaz.

Contractualisation and billing for the Pirineos network interconnection point (PIR) are carried out by TIGF.

3.1.2.2 Capacity subscription at the Dunkerque and Jura PIRs

Daily capacity subscriptions at the Dunkerque and Jura PIRs are subject to specific marketing mechanisms, which are defined in accordance with rules made public on the GRTgaz website.

At the Dunkerque PIR in particular, firm capacities are defined, which are known as "returnable" and which the shipper undertakes to return at any time in the event of a request from GRTgaz, for a period of one, two, three or four years.

For any shipper that has subscribed to more than 20% of the firm annual capacities marketable at the Dunkerque PIR, a 20% fraction of the part of its subscription above 20% of the firm annual capacities marketable at this point is converted into returnable capacity.

3.1.2.3 Capacity subscription at the PITS

At the Transfer Storage Interconnection Points (PITS), the TSO automatically allocates to the shipper entry and exit capacities in line with the nominal injection and withdrawal capacities the shipper has for a storage group, insofar as maximum network capacities.

3.1.2.4 Capacity subscription at the PITTMs

Holding regasification capacities at a LNG terminal involves the right and obligation to subscribe entry capacities on the transmission system for the relevant periods and levels. In the specific case of the Dunkerque LNG terminal, due to the presence of a dual outlet, this obligation applies on the sum of the reserved capacity on GRTgaz’s network at the Dunkerque PITTM and reserved capacity from the terminal to Belgium.

At the Dunkerque PITTM, the firm entry capacities in 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 bands lasting 10 days or more.

At the Montoir and Fos PITTMs, all shippers who have subscribed to capacities with LNG terminal operators are allocated daily firm entry capacities by the TSO, for the entire subscription period for the corresponding regasification capacities:

- for multi-year regasification capacity subscriptions, the daily firm entry capacity allocated is a share of the total daily firm entry capacity at the PITTM. This share is calculated using the ratio:
    - the annual regasification capacity subscribed to by the shipper at the terminals;
    - to the total annual firm technical regasification capacity of the Montoir LNG terminal for the Montoir PITTM, or the sum of the total annual firm technical regasification capacity of the Fos Cavaou LNG terminal and the total annual firm subscribed regasification capacity of the Fos

Tonkin terminal for the Fos PITTM;

- where regasification capacity subscriptions last less than one year, the shipper will be allocated a firm entry capacity band for the subscribed period, with a minimum duration of 10 days. The allocated capacity corresponds with the subscribed regasification capacity, expressed in GWh, divided by the associated subscription duration, express in days.

At the start of each month, the TSO calculates, for each shipper, the daily emissions for each day of the previous month. Should they exceed the shipper's reserved capacity on any given day, the shipper will be billed for an additional daily capacity subscription, at the daily capacity tariff, equal to the positive difference between the actual daily emission and the capacity allocated to the shipper.

As stated in these tariff decision in section 3.1.4, shippers have the option to sell their capacities at the PITTMs.

3.1.2.5 Capacity subscription at exit points from the main network and on the regional network

Reservations of delivery capacities at delivery points and Regional Network Interconnection Points (PIRRs), of transmission capacities on the regional network and of capacities at the main network exit points are made with the TSOs as per the terms published by the TSOs.

Firm delivery capacities at the Transport Distribution Interface Points (PITDs) are automatically allocated by the TSOs. These capacities are calculated by the TSOs using the information provided by the public gas distribution system operator. Standardised delivery capacities are calculated objectively and transparently, with no discrimination, and made public.

The shipper is allocated of an exit capacity from the main network and a transmission capacity to the regional network that are equal to the delivery capacity at each delivery point and for each PIRR.

3.1.2.6 Capacity subscription at the North-South link for GRTgaz

The daily transmission capacities at the GRTgaz North-South link can be subscribed in both south-to-north and north-to-south directions. The marketing rules for these capacities are specified in CRE decision dated 3 February 2016[46].

For reference purposes, the following products are available:

- firm daily transmission capacities for annual, quarterly, monthly, daily and intra-day durations;
- interruptible daily transmission capacities for annual durations only.

Products with annual, quarterly and monthly durations can be subscribed to at auctions via the PRISMA capacity marketing platform.

Daily and intra-daily products are accessed in different ways:

- daily capacities are incorporated into market coupling and marketed in implicit auctions on Powernext;
- the JTS service is marketed in auctions on PRISMA on D-1 for day D, for the north-to-south direction only;
- any unsold capacity is marketed as Use It or Buy It (UBI) on GRTgaz's TRANS@ctions platform. The terms for the auction procedures and characteristics of the products on offer are published by GRTgaz on its website.

Contractualisation and billing are carried out by GRTgaz.

3.1.3 Redistribution of surplus auction capacity revenue

3.1.3.1 Reminder on the calculation of unit amounts applicable from 1 October 2016 to 30 September 2017

The unit redistribution amounts are calculated until 30 September 2017 according to the procedures specified by CRE decision dated 10 December 2015[47].

3.1.3.2 Surplus auction revenue

The price paid by a shipper that acquires capacity at auction is equal to the amount of the auction premium and the regulated price in force at the time of use of the capacity.

[46] CRE proceedings of 3 February 2016 concerning the marketing rules for transmission capacities at the GRTgaz North-South link
[47] CRE proceedings of 10 December 2015 regarding changes to tariff for the use of natural gas transmission systems on 1 April 2016

The excess income related to capacity auctions is equal to the auction premium, in €/MWh/d, multiplied by the capacity sold, in MWh/d.

The surpluses received:

- at the North-South link in the north-to-south direction, and at the interconnections in GRTgaz South and TIGF zones, will be redistributed to shippers delivering to final customers in the GRTgaz South and TIGF balancing zones, pro rata to the volumes consumed in the GRTgaz South and TIGF zones for the period concerned;
- at the North-South link in the south-to-north direction, and at the interconnections in the GRTgaz North zone, will be redistributed to shippers delivering to final customers in the GRTgaz North zone, pro rata to the volumes consumed in the GRTgaz North zone for the period concerned.

3.1.3.3 Calculation of unit amounts applicable from 1 October 2017 to 30 September 2018

3.1.3.3.1 General principles

The surplus income related to capacity auctions will include, from 1 October 2017:

- surplus income from auctions of quarterly and annual capacity for the period from 1 October 2017 to 30 September 2018;
- surplus income from auctions of monthly and daily capacity over the period from 1 July 2016 to 30 June 2017;
- redistribution variations from 1 July 2016 to 30 June 2017.

The unit redistribution amount is equal to the quotient of the surplus income to be redistributed by the reference value of the quantities eligible for redistribution.

For each shipper, the redistribution amount, implemented by each TSO, is equal to the unit redistribution amount multiplied by the quantities eligible for redistribution for the period concerned.

Concerning income surpluses generated by the North-South link, in the north-to-south direction, the volumes consumed pursuant to capacity obtained between 1 October 2014 and 30 September 2018 by a gas-intensive site or by the agent of a gas-intensive site during the capacity allocation phase at regulated prices are not eligible for this redistribution. For each shipper delivering to a gas-intensive site, the volumes excluding redistribution are calculated by multiplying:

- the total volume consumed by this site for the period in question;
- by the capacity quotient obtained during the capacity allocation phase at regulated prices by the site concerned or its agent and the average of the total delivery capacity subscribed to in 2012 and 2013 for the site from the operator to which it is connected (GRTgaz or DSO). In the case where the site is connected to a distribution system, the DSO concerned will send GRTgaz the volumes consumed by the site connected to its network.

If the gas-intensive site is connected downstream of another site directly connected the GRTgaz or DSO network, the volumes excluded from redistribution are calculated by multiplying:

- the total volume measured by GRTgaz at the metering point for the site directly connected to the network;
- by the capacity quotient obtained during the capacity allocation phase at regulated prices by the shipper for the gas-intensive site downstream of the connected site and the average of the total delivery capacity subscribed to in 2012 and 2013 for the site directly connected to the network. In the case where the gas-intensive site is downstream of a site connected to a distribution system, the DSO concerned will send the volumes consumed by the site connected to its network to GRTgaz.

There are two types of capacity obtained during the capacity allocation phase at regulated prices: firm or interruptible. In order to take into account the nature of the capacity, the volume calculations excluded from the scope of redistribution will use a capacity equal to:

- 100% of the firm capacity obtained;
- 50% of the interruptible capacity obtained.

3.1.3.3.2 The calculation of annual redistribution unit amounts for annual product auction surpluses from 1 October 2017 to 30 September 2018

The unit redistribution amount for annual products between 1 October 2017 and 30 September 2018 is equal to a quotient of:

- the surplus income from auctioning annual capacity;
- by the consumption observed in the GRTgaz South and TIGF zone (GRTgaz North respectively) from 1 January to 31 December 2016 reduced, for the North-South link only, by the volumes excluded in relation to capacity obtained during the capacity allocation phase at regulated prices for gas-intensive sites located in the GRTgaz South and TIGF zone;

3.1.3.3.3 The calculation of quarterly redistribution unit amounts for quarterly product auction surpluses from 1 October 2017 to 30 September 2018

For each quarter, the unit redistribution amount for quarterly products between 1 October 2017 and 30 September 2018 is equal to the quotient of:

- the surplus income from auctioning quarterly capacity for the quarter in question;
- by the consumption observed in the GRTgaz South and TIGF zone (GRTgaz North respectively) for the quarter corresponding to the 2016 calendar year reduced, for the North-South link only, by the volumes excluded in relation to capacity obtained during the capacity allocation phase at regulated prices for gas-intensive sites located in the GRTgaz South and TIGF zone.

3.1.3.3.4 The calculation of quarterly redistribution unit amounts for monthly and daily product auction surpluses from 1 July 2016 to 30 June 2017

For each quarter, the unit redistribution amount for monthly and daily products between 1 October 2017 and 30 September 2018 is equal to the quotient of:

- the surplus income from auctions of monthly and daily capacity for the corresponding quarter between 1 July 2016 and 30 June 2017;
- by the consumption observed in the GRTgaz South and TIGF zone (GRTgaz North respectively) over the quarter corresponding to the 2016 calendar year reduced, for the North-South link only, by the volumes excluded in relation to capacity obtained during the capacity allocation phase at regulated prices for gas-intensive sites located in the GRTgaz South and TIGF zone.

3.1.3.3.5 The calculation of quarterly redistribution unit amounts for redistribution variations observed from 1 July 2016 to 30 June 2017

For each quarter, the quarterly unit redistribution amount between 1 October 2017 and 30 September 2018 pursuant to redistribution variations is equal to the quotient:

- of the positive or negative variations between:
  - o the projected redistribution amounts in relation to annual and quarterly capacity for the corresponding quarter between 1 July 2016 and 30 September 2017;

  and
  - o the amounts actually redistributed for the corresponding quarter between 1 July 2016 and 30 June 2017 in relation to annual and quarterly capacities;
- by the consumption that took place in the GRTgaz South and TIGF zone (GRTgaz North respectively) over the quarter corresponding to the 2016 calendar year reduced, for the North-South link only, by the volumes excluded in relation to capacity obtained during the capacity allocation phase at regulated prices for gas-intensive sites located in the GRTgaz South and TIGF zone.

3.1.3.4 Publication of the unit redistribution amounts from 1 October 2017 to 30 September 2018

The unit redistribution amounts from 1 October 2017 to 30 September 2018 will be calculated by each TSO, communicated to CRE before 30 August 2017, and published by the TSO before 15 September 2017 except in the case of objection by the CRE.

For each quarter, the total unit redistribution amount is equal to the sum of:

- the annual unit redistribution amount for annual product auction surpluses from 1 October 2017 to 30 September 2018;

- the quarterly unit redistribution amount for quarterly product auction surpluses from 1 October 2017 to 30 September 2018;
- the quarterly unit redistribution amount for monthly and daily product auction surpluses from 1 July 2016 to 30 June 2017;
- and the quarterly unit redistribution amount of redistribution variations observed from 1 July 2016 to 30 June 2017.

3.1.3.5 Conditions for redistributing surplus auction revenue

Redistribution will be performed once per quarter at the latest on the transmission invoice for the first month of the following quarter.

For each shipper, the redistribution will be calculated by each TSO by multiplying the total unit redistribution amount for the quarter in question by the volumes that are allocated to it by the TSO at points of consumption, minus the volumes excluded pursuant to the capacity allocation phase at regulated prices for gas-intensive sites in the case of the North-South link.

In the case of the North-South link, for each shipper delivering to a gas-intensive site that has obtained, directly or through an agent, capacity during the capacity allocation phase at regulated prices for gas-intensive sites, the volumes excluded from redistribution are calculated by multiplying:

- the total volume consumed by this site during the quarter in question;
- by the quotient of:
  - o the sum of the firm capacity and half of the interruptible capacity obtained during the capacity allocation phase at regulated prices for gas-intensive sites for the site in question;
  - o by the average delivery capacity subscribed for the site during years 2012 and 2013.

3.1.4 Transfer of transmission capacity on the GRTgaz and TIGF networks

The subscribed transmission capacity at the entry and exit points towards the PIRs and connections between balancing zones may be freely transferred without additional cost.

In case of a complete transfer, the acquirer recovers all rights and obligations related to these subscriptions.

In case of transferring usage rights, the initial owner retains its obligations in relation to the TSO. The usage right that is traded may go as low as a daily time-step, whatever the initial subscription period.

The usage rights for downstream transmission capacity, between the PEG and delivery point at an industrial site directly connected to the transmission system, is transferable in the case where the industrial partner concerned has subscribed capacity from the TSO.

The procedures for these transfers of transmission capacity are defined by the TSOs, on an objective and transparent basis that prevents any discrimination, and made public by the TSO on their website.

3.2 Usage tariff schedule for GRTgaz and TIGF networks applicable from 1 April 2017

3.2.1 Allowed revenues to be collected by the transmission tariff

The tariffs and projected tariff changes are fixed depending on capacity subscription forecasts, so as to cover the allowed revenues for each of the TSOs. The 2017 allowed revenue and projected 2018-2020 allowed revenues are shown in the following tables:

- GRTgaz:

GRTgaz, in €m current	2017	2018	2019	2020
Net operating expenses *	764	777	791	804
Normative capital charges	993	1,007	1,068	1,071
Clearance of the CRCP (remainder from previous CRCP accounts + 2015 balance + 2016 estimate)	-28	-28	-28	-28
Inter-operator financial compensation	-	**-3**	**-18**	**-18**
Allowed revenue *Change*	**1,729** *-6.1%*	**1,753** *+1.4%*	**1,813** *+3.4%*	**1,829** *+0.9%*

* Based on a CPI forecast of 1%

- TIGF:

TIGF, in €m current	2017	2018	2019	2020
Net operating expenses *	76	78	79	81
Normative capital charges	159	165	175	180
Clearance of the CRCP (remainder from previous CRCP + 2015 balance + 2016 estimate)	-0.9	-0.9	-0.9	-0.9
Inter-operator financial compensation	-	3	18	18
Allowed revenue *Change*	**234** *-5.0%*	**245** *+4.6%*	**272** *+11%*	**279** *+2.6%*

* Based on a CPI forecast of 1%

3.2.2 Tariffs applicable to annual subscriptions for daily transmission and delivery capacity

3.2.2.1 Pricing for Network Interconnection Points (PIRs)

The applicable tariffs for annual daily capacity subscriptions are defined in the following tables. When marketing at auctions, the auction reserve prices are equal to these tariffs.

- <u>Entry capacity charges (TCEs) for the main network</u>

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm annual*	TCE (coefficient on firm) *Interruptible annual*
Taisnières L	GRTgaz – North B	79.57	50%
Taisnières H	GRTgaz - North	102.30	50%
Dunkerque (PIR)	GRTgaz - North	102.30	N/A
Obergailbach	GRTgaz - North	102.30	50%
Pirineos	TIGF	102.30	75%

- Exit capacity charges at the PIRs (TCST)

Exit at	Balancing zone	TCST (€/MWh/day per year) *Firm annual*	TCST (coefficient on firm) *Interruptible annual*
Alveringem	GRTgaz - North	40.32	N/A
Oltingue	GRTgaz - North	396.64	75%
Jura	GRTgaz - South	94.07	75%
Pirineos	TIGF	494.22	75%

- Backhaul entry capacity charges

Entry at	Balancing zone	coefficient on firm *Backhaul annual*
Alveringem	GRTgaz - North	125%
Oltingue	GRTgaz - North	20%
Jura	GRTgaz - South	20%

- Backhaul exit capacity charges

Exit at	Balancing zone	coefficient on firm *Backhaul annual*
Taisnières H	GRTgaz - North	20%
Obergailbach	GRTgaz - North	20%

- Returnable capacity

The price of an annual returnable capacity is equal to 90% of the price of the corresponding firm annual capacity.

3.2.2.2 Pricing for LNG Terminal Transmission Interface Points (PITTMs)

- Entry capacity charges (TCEs) for the main network

Entry at	Balancing zone	TCE (€/MWh/day per year) *Firm subscriptions*
Dunkerque GNL	GRTgaz - North	96.62
Montoir	GRTgaz - North	96.62
Fos	GRTgaz - South	96.62

3.2.2.3 Pricing for the link between the GRTgaz North and South balancing zones

- Capacity charges for connection between balancing zones (TCLZ)

Connection	Link direction	TCLZ (€/MWh/day per year) *Firm annual*	TCLZ (coefficient on firm) *Interruptible annual*
GRTgaz North/South	North to South	208.04	50%
	South to North	50.00	50%

3.2.2.4 Pricing at Transport Storage Interface Point (PITS)

- Storage entry and exit capacity charges (TCES and TCSS)

PITS	Balancing zone	Capacity type	Entry - TCES (€/MWh/day per year) *Annual*	Exit - TCSS (€/MWh/day per year) *Annual*
North-West	GRTgaz - North	Climatic firm	8.92	20.84
North-East	GRTgaz - North	Climatic firm	8.92	20.84
North B	GRTgaz – North B	Climatic firm	8.92	20.84
North Atlantic	GRTgaz - North	Partially interruptible	6.24	14.59
South Atlantic	GRTgaz - South	Partially interruptible	6.24	14.59
South-East	GRTgaz - South	Climatic firm	8.92	20.84
South-West	TIGF	Climatic firm	8.92	20.84

3.2.2.5 Pricing of the exit capacity from the main network to delivery points

- Main network exit capacity charges

Exit from	TCS (€/MWh/day per year) *Firm annual*	TCS (firm price coefficient) *Interruptible annual*
GRTgaz	89.44	50%
TIGF	89.44	50%

3.2.2.6 Pricing for regional network transmission

- Regional network transmission capacity charges (TCR)

Regional network	TCR (€/MWh/day per year) *Firm annual*	TCR (firm price coefficient) *Interruptible annual*
GRTgaz	74.30 x NTR	50%
TIGF	71.84 x NTR	50%

The charges applicable to annual firm daily capacity subscriptions for regional network transmission (TCR) shall be the product of a fixed unit charge and the regional tariff level (NTR) for the delivery point concerned.

The list of delivery points on the GRTgaz and TIGF network, along with their exit zone and NTR value, is provided in appendix 3 of this document.

When a new delivery point is created, GRTgaz or TIGF will calculate the NTR value transparently and in a non-discriminatory way, using a calculation method published on their respective websites.

- Delivery capacity charges (TCL)

Regional network	**Delivery point type**	**TCL (€/MWh/day per year)** ***Firm annual***	**TCL (firm price coefficient)** ***Interruptible annual***
GRTgaz	End consumer connected to the transmission system	29.57	50%
	Highly modulated[48] end consumer connected to the transmission system	30.91	50%
	PIRR	37.96	N/A
	PITD	43.65	N/A
TIGF	End consumer connected to the transmission system	26.03	50%
	PITD	47.04	N/A

If several shippers simultaneously supply an end consumer connected to the transmission system or a PIRR, the fixed charge is split in proportion to their delivery capacity subscriptions.

As of 1 April 2017 the tariff for delivery to the PITD includes, for GRTgaz, charges relating to repair, renewal and replacement operations (called "3R" operations) for delivery point equipment, and for TIGF the operating, maintenance and repair costs for delivery points and network connections, as well as the identical renewal of delivery points.

- Fixed charges per delivery station

Shippers that supply end consumers connected to the transmission system and PIRRs pay a fixed charge per delivery station:

Fixed charge per station	**€/point per station**
GRTgaz	5,705.77
TIGF	2,879.23

3.2.3 Tariff multipliers for transmission and delivery capacity subscriptions lasting less than one year

3.2.3.1 At the Network Interconnection Points (PIRs)

Capacity	**Special conditions**	**Coefficient**
Quarterly	In the event of congestion	1/4 of the annual charge
	Without congestion	1/3 of the annual charge
Monthly	In the event of congestion	1/12 of the annual charge
	Without congestion	1/8 of the annual charge
Daily	N/A	1/30 of the monthly charge
Intra-daily	N/A	Pro rata daily charge based on the number of hours remaining

A point shall be considered congested if, upon allocation of the annual firm products at auction, the capacity sale price is strictly above the reserve price.

3.2.3.2 At the LNG Terminal Transmission Interface Points (PITTMs)

[48] Consumers with an average daily modulated volume higher than 0.8 GWh per day of operation (see section 17)

Capacity	Coefficient
Daily	1/365 of the annual charge

3.2.3.3 At the link between the GRTgaz North and South balancing zones

- Direction: North to South

Capacity	Special conditions	Coefficient
Quarterly	N/A	1/4 of the annual charge
Monthly	N/A	1/12 of the annual charge
Daily	Marketing via “market coupling”	without reserve price
	Other	1/30 of the monthly charge

- Direction: South to North

Capacity	Special conditions	Coefficient
Quarterly	In the event of congestion	1/4 of the annual charge
	Without congestion	1/3 of the annual charge
Monthly	In the event of congestion	1/12 of the annual charge
	Without congestion	1/8 of the annual charge
Daily	Marketing via “market coupling”	without reserve price
	Other	1/30 of the monthly charge

A point shall be considered congested if, upon allocation of the annual firm products at auction, the capacity sale price is strictly above the reserve price.

3.2.3.4 At the Transport Storage Interface Points (PITS)

Capacity	Coefficient
Quarterly	1/3 of the annual charge
Monthly	1/8 of the annual charge
Daily	1/240 of the annual charge

3.2.3.5 At the main network exit, on the regional network, and at delivery

Capacity	Special conditions	Coefficient
Monthly	January - February	8/12 of the annual charge
	December	4/12 of the annual charge
	March - November	2/12 of the annual charge
	April – May – June – September – October	1/12 of the annual charge
	July – August	0.5/12 of the annual charge
Daily	N/A	1/30 of the monthly charge

- Hourly delivery capacity subscription

The hourly delivery capacity shall only apply to end-customers connected to the transmission system.

Any annual, monthly or daily subscriptions for daily delivery capacity gives an entitlement to an hourly delivery capacity equal to 1/20th the subscribed daily delivery capacity (except in the specific case where this hourly capacity is not available).

To receive a higher hourly capacity where possible on the network, the shipper must pay a price supplement *p* equal to:

$$p = (Cmax - C) \times 10 \times (TCL+TCR)$$

Where:

Cmax: Hourly delivery capacity requested by the shipper;

C: Hourly delivery capacity reserved through the annual, monthly or daily subscription for daily delivery capacity;

TCL: Annual, monthly, or daily charge for daily delivery capacity;

TCR: Annual, monthly, or daily charge for daily transmission capacity on the regional network.

3.2.4 Applicable tariffs for annual capacity subscriptions for gas injections into the transmission system from a gas production facility

The charges applicable to annual daily entry capacity subscriptions for the GRTgaz network from Transport Production Interface Points (PITPs) shall be as follows:

- For PITPs with a network entry capacity less than or equal to 5 GWh/d, the applicable charge shall be €9.40/MWh/day per year;
- For PITPs with a network entry capacity greater than 5 GWh/d, the applicable charge shall be defined through a special study and specific decision;
- For PITPs for biomethane production facilities with a network entry capacity of less than or equal to 5 GWh/d, the applicable charge shall be 0.

3.2.5 Pricing for notional gas exchange points

From 1 April 2015, two notional gas exchange points (PEG) allow shippers to exchange quantities of gas:

- The PEG Nord, relating to GRTgaz's North balancing zone;
- the TRS (Trading Region South), relating to the trading region composed of the GRTgaz South and TIGF balancing zones.

The functioning procedures of the PEG are defined by the TSOs, based on objective and transparent criteria and made public on their website.

The access tariff to gas exchange points includes:

- a fixed annual charge, equal to €6,000 per exchange point;
- a charge proportional to the quantities exchanged equal to €0.01 per MWh.

When a shipper has signed a transmission contract with GRTgaz, it pays the tariffs for access to the PEG Nord and TRS to GRTgaz.

When a shipper has signed transmission contracts with GRTgaz and TIGF, it pays the tariffs for access to the PEG Nord and TRS to GRTgaz.

When a shipper has signed a transmission contact only with TIGF, it pays the tariff for access to the TRS to TIGF.

Gas exchanges carried out on an electronic platform may be the subject of deliveries at a gas exchange point by an entity in charge of compensating the exchanges taking place on the platform. The nominations to PEG of a given entity for the purposes of compensation, neutral in relation to the market, are not subject to the charge proportional to quantities exchanged.

3.2.6 Intra-day flexibility service for highly modulated sites

The intra-day flexibility service shall apply to customers connected to the transmission system that have a modulated daily volume greater than 0.8 GWh.

For existing sites, GRTgaz shall evaluate this criterion based on the consumption history for the preceding year. For newly connected sites, this criterion shall be evaluated based on the modulated daily volume for the operating days declared by the site, and then based on a quarterly statement, retroactive to the past period when the criterion is achieved.

Operators of sites subscribing to the intra-day flexibility service must declare an hourly consumption profile to the TSO the day before for the following day and, where applicable, a new profile during the day, in compliance with the published advance notice deadlines. For any change in hourly consumption for the site that is less than ± 10% of its subscribed hourly capacity, the site shall benefit from a margin of tolerance enabling it not to notify GRTgaz of its new hourly consumption profile.

The intra-day flexibility service is not billed.

3.2.7 Short-notice interruptible transmission offers

3.2.7.1 GRTgaz short-notice interruptible transmission offer

An optional interruptible transmission offer is proposed for customers connected to the GRTgaz H gas network, which simultaneously meet the following conditions:

- The annual daily delivery capacity subscription is greater than 10 GWh/d;
- The site's connection point to the GRTgaz network is less than 50 km, as the crow flies, from a PITTM or one of the Dunkerque, Taisnières H or Obergailbach entry points.

To be eligible for this offer, the customer in question must commit to subscribing to this offer or having a shipper subscribe to it with GRTgaz before the connection decision is made.

This offer sets out a reduction or interruption in supply to the sites in question by request from GRTgaz, with advance notice of at least 2 hours, when both of the following conditions are met:

- The quantity of gas physically injected into the network at the closest entry point is less than the daily delivery capacity subscription for the sites benefiting from this interruptible offer within the scope of this entry point;
- The day's temperature is less than the average daily temperature statistically liable to be reached or negatively exceeded more than 20 days per year, with a 2% risk of occurrence.

The interruption conditions shall be defined by GRTgaz, based on objective and transparent criteria to prevent any discrimination, and made public on its website.

Shippers subscribing to this offer shall benefit from a tariff reduction equal to the delivery capacity that they subscribed for this delivery point, multiplied by the sum of:

- 50% of the main network exit capacity charge;
- 50% of the main network entry capacity charge at the nearest entry point.

For a single site, a shipper may not accumulate the tariff reduction granted under this optional offer with tariff reductions granted for:

- Interruptible transmission on regional networks;
- The proximity charge for customers located within the "Dunkerque Region", "Taisnières H Region", or "Obergailbach Region" exit zones;
- The temporary short-notice interruptible transmission offer in the GRTgaz South zone.

Termination of this optional offer shall be subject to a minimum advance notice of four years.

3.2.7.2 Temporary short-notice interruptible transmission offer in the GRTgaz South zone

An optional interruptible transmission offer is proposed, temporarily until the creation of a single marketplace in France, for highly modulated customers connected to the network in the GRTgaz South zone with an annual daily delivery capacity subscription greater than 10 GWh/d.

This offer sets out a reduction or interruption in supply to the sites in question by request from GRTgaz, with advance notice of at least 2 hours, when the interruption rate for interruptible capacity at the North-South link in the north-to-south direction is equal to 100%.

The interruption conditions shall be defined by GRTgaz, based on objective and transparent criteria to prevent any discrimination, and made public on its website.

Shippers subscribing to this offer shall benefit from a tariff reduction equal to the delivery capacity that they subscribed for this delivery point, multiplied by the sum of:

- 50% of the main network exit capacity charge;
- 25% of the regulated tariff at the North-South link in the north-to-south direction.

For a single site, a shipper may not accumulate the tariff reduction granted under this optional offer with tariff reductions granted for:

- Interruptible transmission on regional networks;
- The short-notice interruptible transmission offer.

3.2.8 Proximity charge

The proximity charge is deducted from the monthly invoice of each shipper concerned. It is applied, for each shipper, to the quantity of gas equal, each day, to the minimum between the quantity of gas allocated at the transmission system entry point and the quantity of gas extracted in the associated exit zone.

The proximity charge is also applied to the following entry point / exit zone pairs:

Balancing zone	Entry point	Associated exit zone	TP (€/MWh)
GRTgaz – North B	Taisnières L	Taisnières L Region	0.17
GRTgaz - North	Taisnières H	Taisnières H Region	0.22
GRTgaz - North	Dunkerque	Dunkerque Region	0.22
GRTgaz - North	Obergailbach	Obergailbach Region	0.22

3.2.9 Gas quality conversion

3.2.9.1 H gas to L gas peak conversion service:

GRTgaz markets a firm annual "peak" H gas to L gas conversion service. This service is available to all shippers having H gas in the North balancing zone.

The rate for this tariff is defined in the following table:

	Capacity charge (€/MWh/day per year)	Quantity charge €/MWh
"Peak" service	161.60	0.02

GRTgaz shall define the operating rules for the H gas to L gas quality conversion service, based on objective and transparent criteria preventing any discrimination and published on its website.

3.2.9.2 L gas to H gas conversion service

The L gas to H gas conversion service is available to shippers providing their own L gas from the Taisnières L PIR or a PITP, up to the limit of the physical quantities of L gas in question.

The rate for the L gas to H gas quality conversion service is as follows:

- For the annual interruptible offer, a charge proportional to the annual capacity subscription equal to €22.72/MWh/day per year;
- For the monthly interruptible offer, a charge proportional to the monthly capacity subscription equal to €2.84/MWh/day per month;
- For the daily firm offer, a charge proportional to the daily capacity subscription equal to €0.19/MWh/day per day.

A post hoc control of the L gas quantities physically converted to H gas shall be made based on a calculation of the daily difference between the quantities converted and the quantities allocated to Taisnières L and the PITPs for the L gas network, between 1 April of year N and 31 March of year N+1.

The converted quantities, from which the quantities allocated to Taisnières L and the PITPs for the L gas network are deducted, between 1 April of year N and 31 March of year N+1, shall be entered into a cumulative daily account:

- Each day there is a positive balance in this cumulative account, the shipper shall be invoiced a penalty of €1/MWh up to the cumulative daily imbalance observed, until it is rebalanced;
- If there is a positive balance on 31 March of year N+1, the balance shall be carried forward to the period from 1 April of year N+1 to 31 March of year N+2;

- If there is a negative or zero balance on 31 March of year N+1, the account shall be reset to zero on 1 April of year N+1.

3.2.9.3 Contractual post hoc L to H conversion rate

A contractual L gas to H gas conversion rate shall be billed after the fact to any shipper with use of the Taisnières L PIR, the North L PITS, and physical conversion tools (H to L peak converter) leading to injection of a quantity of L gas into the L network greater than the total consumption of its customers connected to the L network.

This rate shall apply to the difference calculated daily, for each shipper, between the quantity of L gas injected into the network and the total consumption of its customers connected to the L network. However, this rate shall not apply to quantities of L gas injected into the PITPs, nor to shippers providing GRTgaz with an H gas to L gas exchange service.

This rate shall not apply to L gas imbalances that can be attributed to a revision of nominations following a request from GRTgaz as described at 3.2.9.4 below.

The rate for this tariff is set at €1.05/MWh after application of the following tolerance level:

Delivery capacity subscribed on the L gas network	≤ 0.5 GWh/day	> 0.5 GWh/day and ≤ 1 GWh/day	> 1 GWh/day
Tolerance before application of the conversion price	15%	10%	2.5%

3.2.9.4 Inspection of nominations on the L gas physical infrastructure

In circumstances where the physical balance of the L network so requires, GRTgaz may require shippers with capacity on the L transmission system physical infrastructure to revise their nominations on this infrastructure up or down.

3.2.10 Balancing service based on linepack

GRTgaz and TIGF market a balancing service based on linepack, the subscription tariff of which is €0.12/MWh/d/month[49] for any delivery point at industrial sites directly connected to the transmission system or for any delivery point at unprofiled sites attached to a PITD. The subscription price for this service is subject to a tariff rebate of 50% for any delivery point at a profiled site connected to a distribution system.

3.2.11 Penalties for exceeding capacity

3.2.11.1 Penalties for exceeding daily capacity

3.2.11.1.1 Penalty calculation methods for exceeding daily capacity

Each day, overruns on daily exit capacity from the main transmission system on the regional network and on daily delivery capacity will be subject to penalties.

For the part of the overrun less than or equal to 3% of the subscribed daily capacity, no penalty is invoiced.

For the part of the overrun greater than 3%, the penalty calculation is based on the firm daily subscription price for daily capacity, as follows:

- for the part of the overrun between 3% and 10%, the penalty is equal to 20 times the firm daily subscription price for daily capacity;
- for the part of the overrun greater than 10%, the penalty is equal to 40 times the firm daily subscription price for daily capacity.

The TSOs allow shippers to quickly adjust their capacity subscriptions when a capacity overrun is noticed, subject to network availability.

3.2.11.1.2 Calculation methods for daily capacity overruns

- Overrunning daily capacity for regional transmission and delivery for end consumers connected to the transmission system and the PIRRs:

For a given day, the daily capacity overrun value used is equal to the difference, if it is positive, between the quantity of gas delivered and the daily delivery capacity subscribed.

[49] For details of this service, see CRE proceedings of 9 September 2015 regarding changes to the balancing rules on gas transmission systems on 1 October 2015

- <u>Overrunning daily capacity for regional transport and delivery for the PITDs:</u>

For a given day, the daily capacity overrun value used is equal to the difference, if it is positive, between the following two values:

- the value of 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 value of the difference between the sum of the daily quantities delivered to "not for subscription" delivery points and the sum of standardised capacity for "not for subscription" delivery points, if this difference is positive, or zero if this difference is negative.

- <u>Overrunning daily exit capacity from the main network:</u>

For a given day, the daily capacity overrun value used is equal to the difference, if it is positive, between the following two values:

- the value of the difference between the daily quantity of gas delivered and the daily capacity on output from the corresponding main network, if this difference is positive, or zero if this difference is negative;
- the value of the difference between the sum of the daily quantities delivered to "not for subscription" delivery points in the exit zone and the sum of exit zone standardised capacity for the "not for subscription" delivery points, if this difference is positive, or zero if this difference is negative.

In case the option to interrupt is exercised by the TSO, the above overrun calculations are carried out by reducing the interruptible capacity for the interrupted portion requested by the TSO.

3.2.11.2 Penalties for exceeding hourly capacity

Each day, overruns in hourly transmission capacity on the regional and in delivery capacity, in order to supply end consumers connected to the transmission system, are subject to penalties. For a given day, the hourly capacity overrun is calculated by considering the maximum value of the hourly average of quantities delivered to the delivery point concerned over four consecutive hours.

For the part of the overrun less than or equal to 10% of the subscribed hourly capacity, no penalty is invoiced.

For the part of the overrun greater than 10%, the penalty calculation is based on the daily subscription price for hourly capacity, as follows:

- for the part of the overrun between 10% and 20%, the penalty is equal to 45 times the daily subscription price for hourly capacity;
- for the part of the overrun greater than 20%, the penalty is equal to 90 times the daily subscription price for hourly capacity.

The penalties for overrunning hourly capacity are not applied by GRTgaz if the shipper corrects its annual hourly capacity subscription up to the observed level of overrun.

3.2.11.3 Annual redistribution of penalties for exceeding capacity

Each TSO redistributes the amount of penalties for exceeding capacity collected each year, no later than June of the following year.

For each TSO, the amount of penalties to redistribute is divided between shippers in proportion to the quantities of gas delivered to end consumers connected to the transmission system and to PIRRs. Each TSO publishes on its website the unit amount of penalties redistributed this way, expressed in euros per MWh used by end consumers connected to the transmission system.

3.3 References for the annual update of GRTgaz and TIGF networks usage tariff from 1 April 2018

The TSO tariff schedules are updated on 1 April 2018, 2019 and 2020 in accordance with the below procedures:

3.3.1 Update of normative capital charges

For 2017 to 2020, the normative capital charges used to update the tariff schedule on 1 April of each year is that defined in the following table:

Projected NCC, in €m$_{current}$	2017	2018	2019	2020
GRTgaz	993	1,007	1,068	1,071
TIGF	159	165	175	180

3.3.2 Update of net operating expenses

For 2018 to 2020, the net operating expenses (NOE) are updated as shown below:

- the NOE for 2018 (or 2019 or 2020) shall be calculated by applying a variation percentage equal to the CPI + 0.74% for GRTgaz and + 1.04% for TIGF to the net OPEX values for 2017 (or 2018 or 2019), where CPI is the average annual variation actually observed for the previous calendar year for the consumer price index excluding tobacco, as calculated by the French National Statistics Office (INSEE) for all households throughout France[50]. If the observed CPI value is not available at the time of the tariff update, the CPI projection retained for the draft finance law will be used instead. The difference between the inflation actually observed and the forecast from the draft finance law shall be covered 100% by the revenues and expenses clawback account;
- The difference between the projected “energy and CO_2 quotas” item used in the NOE trajectory and the revised projection for this item for 2018 (or 2019 or 2020) is added to the NOE amount for 2018 (or 2019 or 2020);
- Where applicable, the amounts retained by CRE for the increase in any costs linked to flexibility of the L gas network are added to this NOE amount for 2019 and 2020;
- Where applicable, the amounts retained by CRE for the review clause are added to this NOE amount for 2019 and 2020.

Projected NOE, in €m$_{current}$	2017	2018	2019	2020
GRTgaz, with CPI of 1%	764	777	791	804
TIGF, with CPI of 1%	76	78	79	81

3.3.3 Update of compensation level by TIGF to GRTgaz as a portion of the income collected at the Pirineos PIR exit point

The projected repayment amount by TIGF to GRTgaz as a portion of the income received at the Pirineos PIR exit point is determined based on the sum carried over to the exit charge once the single marketplace has been created, applied to the projected subscriptions at this exit point. The projected repayment rate will be reviewed every year to take into account revised subscription forecasts retained by the CRE.

Inter-operator compensation, in €m$_{current}$	2017	2018	2019	2020
GRTgaz	-	-3	-18	-18
TIGF	-	3	18	18

3.3.4 Update of the annual difference between projected income and projected allowed revenue

A charge to take into account the annual difference between projected income and projected allowed revenue, the updated value of which at the risk-free rate of 2.7% is zero over the ATRT6 tariff period, is added to the allowed revenue for operators according to the following figures:

[50] The mean annual variation over the year Y-1 is equal to the rate of change, by percentage, of the annual average index corresponding to the simple arithmetic mean of the 12 monthly indexes for the year, from January to December, of consumer prices excluding tobacco for all households in the whole of France (series no. 641194), between years Y-2 and Y-1.

Annual difference, in €m$_{current}$	2017	2018	2019	2020
GRTgaz	+48	+26	-54	-24
TIGF	+5	+1	-4	-3

3.3.5 Calculation and clearance of the revenues and expenses clawback account balance (CRCP)

The overall clawback account balance is equal to the amount paid into or deducted from the clawback account for the past year and the year before that, plus the clawback account balance not cleared for previous years.

The amount to be paid into or deducted from the clawback account is calculated by the CRE, for each full year, based on the actual difference with each item to the reference amounts given below. All or part of the difference is paid to the clawback account, and the quota is determined based on the coverage rate stipulated by this decision.

GRTgaz, in €m$_{current}$	Rate	2017	2018	2019	2020
"Downstream" transmission revenues	100%	**1,327**	Updated annually as per 1.2.2		
"Upstream" transmission revenues	80%	**451**			
CCGT and CT connection products	100%	**2**	3	6	0
"Network" normative capital charges	100%	**900**	909	964	970
Motive energy costs and difference between income and expenditure related to CO_2 quotas	80%	**92**	Updated annually as per 1.2.2		
Charges for H-L conversion services (difference in converted volumes)	100%	**46**	51	56	56
Charges to be paid by GRTgaz after the pilot project to convert the area supplied by L gas to H gas	100%	**0**	0	0	0
Charges linked to extricating R&D activities from those of the parent company	100%	**4**	3	1	0
Service products for third parties associated with major landworks projects	100%	**34**	34	32	37
Any potential charges associated with remunerating consumers connected to the transmission system linked to implementing the provisions of article L.431-6-2 of the Energy Code	100%	**0**	0	0	0
Charges and products relating to the contract between GRTgaz and TIGF (expenditure)	100%	**34**	34	34	35
Inter-operator compensation between GRTgaz and TIGF (income)	100%	**0**	3	18	18

TIGF, in €m_{current}	Rate	2017	2018	2019	2020
"Downstream" transmission revenues	100%	**146**	Updated annually as per 1.2.2		
"Upstream" transmission revenues	80%	**94**			
CCGT and CT connection products	100%	**0**	0	0	0
"Network" standard capital charges	100%	**140**	143	155	158
Motive energy costs and difference between income and expenditure related to CO_2 quotas	80%	**7**	Updated annually as per 1.2.2		
Service products for third parties associated with major landworks projects	100%	**0**	0	0	0
Any potential charges associated with remunerating consumers connected to the transmission system linked to implementing the provisions of article L.431-6-2 of the Energy Code	100%	**0**	0	0	0
Charges and products relating to the contract between GRTgaz and TIGF (income)	100%	**34**	34	34	35
Inter-operator compensation between GRTgaz and TIGF (expenditure)	100%	**0**	3	18	18

To determine the final differences to repay to the clawback account for 2016, the reference amounts and coverage rates are defined in the proceedings of 19 March 2016[51].

Furthermore, the following points are also incorporated into the clawback account:

- differences in operating costs or "non-network" capital expenditure due to differences between the forecast CPI and actual CPI;
- rewards/sanctions as part of the service quality incentive regulation;
- bonuses/penalties as part of the investment incentive regulation mechanisms.

An interest rate equal to the risk-free rate, 2.7%, shall apply annually to the overall clawback account balance.

For the years 2018 to 2020, the annual update to the tariff schedule on 1 April includes the clearance of a quarter of the overall clawback account balance on 31 December the previous year.

3.3.6 Update of the capacity subscription estimates

For 2018 to 2020, the annual estimates for capacity subscriptions will be reviewed while updating the tariff schedule on 1 April each year.

3.3.7 Tariffs evolution

Tariffs will evolve during the 2018-2020 according the following rule:

- Tariffs at PIR,PITTM and PITS will grow each year at inflation rate, except for the PIR Pirineos exit point that will be raised of a part of the North-South link price at the creation of the single French market place;
- North-South link fares will remain constant until the creation of the single French market place;
- Exit term from the main network to regional network will evolve according inflation rate and regional networks tariffs of GRTgaz and TIGF will evolve of respectively +4.5%/y and +5.4%/y, in order to cover the allowed revenue updated with up to date hypothesis on charges and capacity subscriptions.

[51] http://www.cre.fr/documents/deliberations/decision/tarifs-atrt5

APPENDIX 1: TARIFF SCHEDULE SUMMARY TABLE APPLICABLE FROM 1 APRIL 2017

This appendix summarises the main tariff charges described in part 3.

Access to the Notional Gas Exchange Points (PEG)

Fixed annual charge: **€6000/exchange point/year**
Variable charge: **€0.01/MWh exchanged**

Charges applicable to the main network

	Capacity charge (€/MWh/d/year)		
Entry to Network Interconnection Points (PIRs)	Firm	Interruptible	Backhaul
GRTgaz - Taisnières L	79.57	50%	
GRTgaz - Taisnières H	102.30	50%	20%
GRTgaz - Dunkerque	102.30		
GRTgaz - Obergailbach	102.30	50%	20%
TIGF - Pirineos	102.30	75%	

	Capacity charge (€/MWh/d/year)		
Exit to Network Interconnection Points (PIRs)	Firm	Interruptible	Backhaul
GRTgaz - Alveringem	40.32		125%
GRTgaz - Oltingue	396.64	75%	20%
GRTgaz - Jura	94.07	75%	20%
TIGF - Pirineos	494.22	75%	

	Capacity charge (€/MWh/d/year)
Entry to LNG Terminal Interconnection Points (PITTMs)	Firm
GRTgaz - Dunkerque LNG	96.62
GRTgaz - Montoir	96.62
GRTgaz - Fos	96.62

	Capacity charge (€/MWh/d/year)	
Entry/exit to Transport Storage Interface Points (PITS)	Entry	Exit
GRTgaz - North-West, North-East, North L, South-East	8.92	20.84
GRTgaz - North-Atlantic, South-Atlantic	6.24	14.59
TIGF – South-West	8.92	20.84

	Capacity charge (€/MWh/d/year)	
North-South link	Firm	Interruptible
North to South Direction	208.04	50%
South to North Direction	50.00	50%

	Capacity charge (€/MWh/d/year)	
Exit from main network to delivery points (TCS)	Firm	Interruptible
GRTgaz	89.44	50%
TIGF	89.44	50%

Charges applicable to the regional networks

	Capacity charge (€/MWh/d/year)	
Transmission capacity on the regional network (TCR)	Firm	Interruptible
GRTgaz	74.30 x NTR	50%
TIGF	71.84 x NTR	50%

The Regional Tariff Level (NTR) is defined for each delivery point from 0 to 10

	Capacity charge (€/MWh/d/year)	
Delivery capacity (TCL)	Firm	Interruptible
GRTgaz - End consumer connected to the transmission system	29.57	50%
GRTgaz - Highly modulated end consumer	30.91	50%
GRTgaz - PIRR	37.96	
GRTgaz - PITD	43.65	
TIGF - End consumer connected to the transmission system	26.03	50%
TIGF - PITD	47.04	

	Charge per station (€/point/year)
Delivery station	Firm
GRTgaz	5,705.77
TIGF	2,879.23

APPENDIX 2: INDICATORS FOR MONITORING TSO SERVICE QUALITY

In application of the principles defined in the method section of the present tariff ruling, a mechanism for monitoring service quality is established for the two TSOs in the key areas of their activity. This monitoring is composed of indicators submitted by the TSOs each month to CRE and made public on their website.

Some indicators that are especially important for correct operation of the market are subject to a system of financial incentives.

The following indicators are subject to a financial incentive:

- quality of measured quantities at the PITDs and sent to the DSOs the day after to calculate provisional allocations;
- quality of daily quantities remotely read at the delivery points for consumers connected to the transmission system and sent the day after;
- quality of intra-day quantities remotely read at the delivery points for consumers connected to the transmission system and sent during the day;
- quality of overall forecasts for end of gas day consumption performed the night before and during the day;
- monitoring the provision of the five items of information most useful for balancing on the TSOs' public sites.

The following indicators are monitored without being subject to a financial incentive:

- availability rate of TSO user portals and public data platforms;
- provision of additional firm capacity on the market at the North-South link;
- reliability of the projected working stock indicator published by the TSOs on their public page;
- reduction of available capacity;
- reduction of subscribed capacity;
- compliance with the annual maintenance programme published at the beginning of the year by the TSO;
- compliance with the committal maintenance programme published in M-2 by the TSO;
- compliance with the non-committal maintenance projection published in M-2 by the TSO;
- compliance with the maintenance programme relating to interruptible capacity on the North-South link published in M-2 by GRTgaz;
- greenhouse gas emissions;
- greenhouse gas emissions related to the volume of gas transported.

The service quality regulation system may change during the ATRT6 tariff period. It may be subject to any audit that CRE considers relevant.

The TSOs are authorised to write off one day per year to calculate the indicators, during the commissioning of a major version of an application contributing to the production of said indicators. They are required to communicate to market participants the tentative date for commissioning at least one month in advance, and then to confirm one week before the actual date of this commissioning.

1. TSO service quality monitoring indicators that give rise to financial incentives

1.1 Quality of measured quantities at the PITDs and sent to the DSOs the day after to calculate provisional allocations

Calculation:	Number of non-compliant(1) days per balancing zone and per month (one value monitored per balancing zone, so two values monitored by GRTgaz and one value monitored by TIGF)
Scope:	- all shippers combined - all DSOs combined - per Transmission Balancing Area (ZET)
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly - frequency of financial incentive calculation: monthly
Objective:	GRTgaz: - basic objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month TIGF: - basic objective: 1 non-compliant day per month - target objective: 0 non-compliant days per month
Incentives:	GRTgaz: - penalties/month: • €20k for the 2nd non-compliant day; • €30k per non-compliant day after the 3rd non-compliant day; - bonuses/month: €25k if the target objective is achieved; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is capped at around €600k per year for all balancing zones. TIGF: - penalties/month: • €20k for the 2nd non-compliant day; • €30k per non-compliant day after the 3rd non-compliant day; - bonuses/month: €25k if the target objective is achieved; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by TIGF, is capped at around €300k per year.
Implementation date	- 1 April 2016

(1): For a given transmission balancing zone (ZET), a day D of month M is non-compliant if the variation, in absolute terms, between the following values is strictly greater than 2%:

- *the provisional quality measurement of the gas delivered to all PITDs in the ZET on day D and sent to the DSOs on day D+1 of month M;*
- *the final quality measurement of the gas delivered to all PITDs in the ZET on day D and sent to the DSOs on the 20th of month M+1.*

1.2 Quality of daily quantities remotely read at the delivery points for consumers connected to the transmission system and sent the day after

Calculation:	- Very good quality rate of information(4) - Good quality rate of information - Poor quality rate of information (three values monitored for each TSO)
Scope:	- all shippers combined - all ZETs combined - all remotely-read industrial delivery points - rounded to one decimal place
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly - frequency of financial incentive calculation: monthly
Incentives:	**GRTgaz:** The financial incentive relates to the monthly average of very good and poor quality rates of information. - penalties/month: €60k per percent of poor quality information; - bonuses/month: €1k per percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by each TSO, is capped at around €600k per year. **TIGF:** The financial incentive relates to the monthly average of very good and poor quality rates of information. - penalties/month: €30k per percent of poor quality information; - bonuses/month: €500 per percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by TIGF, is capped at around €300k per year.
Implementation date	- 1 April 2015

(4): Information is said to be of very good quality if the variation, in absolute terms, between the energy reading for day D sent on day D+1 and the final reading for day D sent in M+1 is strictly below 1%. If the deviation is between 1% and 3% (or strictly higher than 3%), the value is of good quality (or poor quality).

1.3 Quality of intra-day quantities remotely read at the delivery points for consumers connected to the transmission system and sent during the day

Calculation:	- Very good quality rate of information(1) - Good quality rate of information - Poor quality rate of information (three values monitored by GRTgaz and TIGF per timeslot)
Scope:	- calculation for the following timeslots: 06:00-10:00, 06:00-14:00, 06:00-18:00, 06:00-22:00 and 06:00-01:00 - all shippers combined - all ZETs combined - all remotely-read industrial delivery points - rounded to the nearest percent
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly - frequency of financial incentive calculation: monthly
Incentives:	The financial incentive relates to the average, all timeslots combined, of very good and poor rates of information. GRTgaz: - penalties/month: €20k per percent of poor quality information; - bonuses/month: €1k per percent of very good quality information; - cap: the total annual amount, corresponding to the sum, over all timeslots, of penalties to be paid and bonuses to be received by GRTgaz, is capped at around €600k per year. TIGF - penalties/month: €10k per percent of poor quality information; - bonuses/month: €500 per percent of very good quality information; - cap: the total annual amount, corresponding to the sum, over all timeslots, of penalties to be paid and bonuses to be received by TIGF, is capped at more or less €300k per year.
Implementation date	- 1 April 2014

(1): Information is said to be of very good quality if the variation, in absolute terms, between the energy reading in the timeslot for day D sent on day D and the final reading in the timeslot for day D sent in M+1 is strictly below 1%. If the deviation is between 1% and 3% (or strictly higher than 3%), the value is of good quality (or poor quality). If the deviation is less than 100kWh, the information is of very good quality.

1.4 Quality of overall forecasts for end of gas day consumption performed the night before and during the day

Calculation:	- Very good quality rate of information(1) - Good quality rate of information - Poor quality rate of information (one rate per balancing zone for the values published the day before and during the day, so six values monitored by GRTgaz and three values monitored by TIGF)
Scope:	- all shippers combined - one value per ZET - rounded to one decimal place
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly - frequency of financial incentive calculation: monthly
Incentives:	The financial incentive relates to the average of very good and poor quality rates of information. **GRTgaz:** For the values published the day before (D-1) and during the day (D): - penalties: €40 per tenth of a percent of poor quality information; - bonuses: €10 per tenth of a percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is capped at around €600k per year for all balancing zones. **TIGF:** For the values published the day before (D-1) and during the day (D): - penalties: €40 per tenth of a percent of poor quality information; - bonuses: €10 per tenth of a percent of very good quality information; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by TIGF, is capped at around €300k per year.
Implementation date:	- 1 April 2014

(1): For the forecast made the day before, information is said to be of very good, good, and poor quality if the variation, in absolute terms, between the following values is strictly less than 4%, between 4% and 7%, and strictly greater than 7% respectively:

- *the consumption forecast for day D published the day before at 17:00;*
- *the final reading for energy used on day D sent on the 20th of M+1.*

For the forecast made during the day, information is said to be of very good, good, and poor quality if the variation, in absolute terms, between the following values is strictly less than 3%, between 3% and 5%, and strictly greater than 5% respectively:

- *the consumption forecast for day D published on day D at 15:00;*
- *the final reading for energy used on day D.*

The overall forecasts for end of gas day consumption used to calculate the indicator concern industrial customers, excluding highly modulated sites, and public distributions connected to the TSO's network.

1.5 Monitoring the provision of the five items of information most useful for balancing on the TSOs' public sites

An indicator used to monitor the regular updating of the five most important pieces of information published on the TSOs' public websites was introduced on 1 April 2016. This indicator is now incentivised.

The five pieces of information monitored via this indicator are:

Information	Publishing frequency	Inspection frequency	Quality threshold
Projected working stock	Once an hour with a one-hour delay	Once per hour(1) (information published or not at H+1:15)	**Monitored value: availability rate before H+1:15**
Forecast imbalance	Once an hour with a one-hour delay	Once per hour(1)	**Monitored value: availability rate before H+1:15**
Price of regulating imbalances	Hourly, each time Powernext is refreshed	1 inspection per hour(1)	**Monitored value: average of overall monthly availability rates for each price** (average weighted price, marginal sale price, marginal purchase price)
Overall consumption forecast per zone D and D+1	-15:00: D forecasts -17:00: D+1 forecasts	Twice per day (information published or not at H+15 for 15:00 and 17:00)	**Monitored value: availability rate before H+15**
Pirineos E and L allocations	Daily, before 13:00	Once per day(2)	Indicator indexed on the presence of the data every day at 14:00. **Monitored value: availability rate at 14:00**
Incentives:	Once a month, each TSO calculates the average of all monitored values. The incentive applies to this average, expressed as a percentage rounded to one decimal place. **GRTgaz:** - if this average is equal to 100%, the bonus is €40k/month; - if this average is less than or equal to 95%, the penalty is €40k/month; - if this average is between 95% and 100%, the bonus/penalty applied is linear to the two values stated above: *incentive = average x 1600 – 1560,* expressed in €k; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by GRTgaz, is capped at around €600k per year. **TIGF:** - if this average is equal to 100%, the bonus is €20k/month; - if this average is less than or equal to 95%, the penalty is €20k/month; - if this average is between 95% and 100%, the bonus/penalty applied is linear to the two values stated above: *incentive = average x 800 – 780,* expressed in €k; - cap: the total annual amount, corresponding to the sum of penalties to be paid and bonuses to be received by TIGF, is capped at around €300k per year.		
Implementation date:	- 1 April 2016		

(1) These checks are carried out every hour, except in between the 00:00 - 06:00 timeslot.
(2) Days for which this value is amended after initial publication will be counted as days for which this data is missing.

2. Other indicators for monitoring TSO service quality

2.1 Availability rate of TSO user portals and public data platforms

Calculation:	Number of hours the user portal and public platform for public data are available over the month / Total number of opening hours specified for both interfaces over the month (a value monitored by the TSO)
Scope:	- calculated for a usage time between 07:00 and 23:00, 7 days a week - rounded to one decimal place
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly
Implementation date:	- 1 April 2015

2.2 Provision of additional firm capacity on the market at the North-South link

Calculation:	Annual combined volume of additional firm daily capacity marketed by GRTgaz at the North-South link, in the north-to-south direction
Scope:	- Combined interruptible and firm daily capacity marketed beyond 270 GWh/day
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly
Implementation date:	- 1 January 2015

2.3 Reliability of the projected working stock indicator published by the TSOs on their public page

The projected working stock indicator is an estimation by the TSOs of the gas levels in each balancing zone at the end of the current gas day (05:00). This indicator provides information about the network voltage, in the same way as the imbalance indicator. The difference between the two indicators lies in the view of the system they provide: the first offers a projected view of the system for the current day, whereas the second gives a static view of a specific moment.

The projected working stock indicator affects TSO interventions in the market. As such, it informs shippers about the availability of flexibility services based on the working stock. When asked by CRE during the tariff update public consultation, the shippers unanimously declared that they would like to see an indicator created to monitor the reliability of this information. The resultant indicator aims to highlight aberrant working stock projected values.

Calculation:	The percentage of hours per month for which the published working stock projection is compliant. The working stock projection published at hour H is deemed compliant if the difference from the last compliant projected working stock value is less than 100 GWh in the North zone, 50 GWh in the South zone, and 30 GWh in the TIGF zone. This tolerance range is designed to isolate deviations that cannot cause client rescheduling and/or consumption re-forecasts.
Scope:	- One value per month per balancing zone (North and South) for GRTgaz and TIGF
Monitoring:	- frequency of calculation: monthly - frequency of reporting to the CRE: monthly - frequency of publication: monthly
Implementation date:	- 1 April 2016

2.4 Indicators relating to maintenance programmes

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Reduction of available capacity	**Firm capacity made available during works / technical firm capacity** (one value monitored per point and an aggregate value monitored for each category of network points(1) for each TSO)	Monthly Indicator calculated for the months **January to December**	1 April 2009
Reduction of subscribed capacity	**Firm capacity made available during works / subscribed firm capacity** (one value per type of network point(1) for each TSO)		1 April 2016
Compliance with the annual maintenance programme published at the beginning of the year by the TSO	**Percentage variation of the capacity made available between the projected maintenance programme published at the beginning of the year and the actual maintenance programme** (one value per type of network point(1) for each TSO)		1 April 2009
Compliance with the committal maintenance programme published in M-2 by the TSO	**Percentage variation of the capacity made available between the projected maintenance programme published in M-2 and the actual maintenance programme** (one value per type of network point(1) for each TSO)		GRTgaz: mid-2009 TIGF: 1 April 2009
Compliance with the non-committal maintenance projection published in M-2 by the TSO	**Percentage variation of the capacity made available between the best-case non-committal maintenance programme published in M-2 and the actual maintenance programme** (one value per type of network point(1) for each TSO)		1 April 2016
Compliance with the maintenance programme relating to interruptible capacity on the North-South link published in M-2 by GRTgaz	**Percentage variation between the projected maintenance programme concerning interruptible capacity published in M-2 and the actual maintenance programme for the North-South link**		1 April 2015

(1): 5 point categories are used:
- *the North-South link in both directions;*
- *PIRs in the dominant direction;*
- *entry to the PITTMs;*
- *entry and exit at the PITS;*
- *GRTgaz South / TIGF interface in both directions.*

2.5 Environmental indicators

Indicator name	Indicator calculation	Frequency of reporting to CRE and publication	Implementation date
Greenhouse gas emissions	**Monthly greenhouse gas emissions (in CO_2 equivalent)** (one value monitored per TSO)	Quarterly	1 January 2009
Greenhouse gas emissions related to the volume of gas transported	**Monthly greenhouse gas emissions / Monthly volume of gas transported** (one value monitored per TSO)		1 January 2009

APPENDIX 3: LIST OF NTRS BY SITE

Appendices published on CRE's website for GRTgaz[52] and TIGF[53]. The present deliberation will be published in the Official Journal of the French Republic.

Signed in Paris, 15 December 2016

On behalf of the Energy Regulatory Commission,

Chairman,

Philippe de Ladoucette

[52] List of GRTgaz NTRs
[53] List of TIGF NTRs