Deliberation of the French Energy Regulatory Commission of 3 April 2013 deciding on the tariffs for the use of a high-voltage public electricity grid

Session participants : Philippe de Ladoucette, Chairman, Olivier Challan Belval, Hélène Gassin, Jean-Pierre Sotura and Michel Thiollière, commissioners.

Introduction

The third set of tariffs for the use of public electricity grids, termed “TURPE 3” entered into force on 1 August 2009, pursuant to the decision of 5 May 2009 approving the tariff proposal by the French Energy Regulatory Commission (CRE) of 26 February 2009.

In the present deliberation, CRE defines the methodology for determining the tariffs for the use of a high-voltage public electricity grid (HTB) and establishes the tariffs termed “TURPE 4 HTB” set to apply as from 1 August 2013.

A separate decision will be made for public medium and low-voltage electricity grid user tariffs in order to take into account the reasons for the State Council’s decision of 28 November 2012 invalidating TURPE 3 in so far as it sets the tariffs for the use of public distribution grids. CRE will take into account the effects of the present tariffs on the level of costs for accessing the public transmission grid for distribution system operators. CRE will take into account, for the setting of tariffs for medium and low-voltage grids, the issues raised by certain stakeholders on the synchronisation of annual evolutions of high-voltage tariffs on the one hand, and medium- and low-voltage tariffs on the other hand.

Legal framework

Articles L. 341-2, L. 341-3 and L. 341-4 of the French Energy Code define CRE’s powers regarding the setting of tariffs for the use of public electricity transmission and distribution grids.

Article L. 341-3 sets out the following provisions:

“The methodologies used to establish tariffs for the use of public electricity transmission and distribution grids are set by the French Energy Regulation Commission. […] The Energy Regulation Commission decides […] on the evolution of tariffs for the use of public electricity transmission and distribution grids […]. It may propose a multiannual tariff framework together with appropriate short- or long-term incentives to encourage transmission and distribution grid operators to improve their performance particularly as regards the quality of the electricity, to encourage the integration of the domestic electricity market and security of supply and to find ways to improve productivity”.

The Energy Regulation Commission takes into account the energy policy guidelines indicated by the administrative authority. It regularly informs the administrative authority during the tariff establishment phase. It consults energy market stakeholders as it sees fit.

COMMISSION DE RÉGULATION DE L’ÉNERGIE

The Energy Regulation Commission transmits to the administrative authority, for publication in the Journal Officiel de la République Française*, its reasoned decisions on changes in the level and structure of tariffs for the use of public electricity transmission and distribution grids, [...] on the date of entry into force of these tariffs.*"

Article L. 341-4 of the Energy Code specifies that "*the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which consumption of all consumers is at its highest".*

To establish these new tariffs, CRE has also taken into account the legislative and regulatory framework related to the Third Energy Package which sets independence obligations on French electricity transmission system operator RTE within the framework of the implementation of the independent transmission operator model (ITO model). One of the main aims of the ITO model is to make investment decisions made by RTE independent of the specific interests of the consolidated group to which it belongs. To that end, Article L.111-19 of the Energy Code specifies that the public transmission system operator must have all the financial resources necessary to carry out its transmission activity. Therefore, the vertically integrated undertaking EDF[1] must, as a shareholder, make available to the public transmission system operator the appropriate financial resources for future investment projects and/or for the replacement of existing assets. Pursuant to Article L. 111-13 of the Energy Code, the supervisory board of the public transmission system operator is responsible for making decisions "*regarding the approval of its annual and pluriannual financial plans, its level of debt and the amount of dividends distributed to shareholders*"*.*

<u>Tariff works</u>

RTE requested new tariffs on 27 July 2012. This request led to a 5.2% tariff increase as at 1 August 2013 followed by annual increases from 2014 to 2016 equivalent to inflation plus 1%.

CRE conducted analyses of RTE's business plan and drew on different studies assigned to external consultants:

- an international comparative study on incentive regulation mechanisms;
- a study on the costs structure of public electricity transmission and distribution grids;
- a study on the tarification methods for public electricity grids;
- a study on interconnection development incentives and on the estimated trajectory of income related to the mechanisms for congestion management at interconnections (also called auction income);
- a study on the weighted average cost of capital of electricity and natural gas infrastructure.

CRE carried out four public consultations on the following topics:

[1] Vertically integrated undertaking EDF to which RTE belongs, as defined by CRE in its deliberation of 26 January 2012 deciding to certify the RTE company.

- the structure of the tariffs for the use of public electricity transmission and distribution grids (15 July 2010 then 6 March 2012);
- the regulatory framework for public electricity grid access tariffs (7 June 2012);
- the expenses to be covered by the public electricity grid access tariffs, regulatory framework, tariff structure and tariff rules (6 November 2012).

Summaries of these consultations have been published[2] on CRE's website.

CRE gave audience on several occasions to RTE, its shareholder as well as all market stakeholders in July 2012 and then in December 2012.

Lastly, pursuant to the provisions of Article L. 341-3 of the French Energy Code, CRE took into account the energy policy guidelines posted by the Minister of Ecology, Sustainable Development and Energy on 10 October 2012. These guidelines cover the incentives for interconnection development and improvement of the security of supply, the hourly/seasonal structure of tariffs and the injection tariff. The guidelines can be consulted on CRE's website.

<u>Main developments</u>

On the basis of all of these elements, CRE has renewed and reinforced the existing pluriannual regulatory framework encouraging RTE to improve cost control and the quality of service provided to users. It has introduced a financial incentive for interconnection development as well as follow-up of the actions undertaken by RTE to control the volume of losses. It has also implemented a regulatory framework favourable to research and development (R&D).

With regard to tariff structure, the present tariff decision makes major changes, in particular the introduction of a distinction in the prices for the power subscribed and the use of this power according to the periods of the year and the hours in the day in order to encourage users to limit their demand during peak periods, pursuant to the provisions of Article L. 341-4 of the Energy Code.

With regard to tariff changes, CRE has retained a 2.4% increase at 1 August 2013 followed by inflation-linked indexation, excluding any differences between estimated and actual trajectories for items included within the scope of the expense and income clawback account (CRCP).

The tariff increase retained for 2013 (+2.4%)[3] is due mainly to the following factors:

- the increase in operating and capital expenses (contributing +3.1% to the increase);
- the increase in the level and structure of consumption according to voltage level (for +2.7%);
- the effects of the use of the same reference period for expenses and income (for +1.4%);

[2] The summaries of the consultations of 6 March and 7 June 2012 were published in June and September 2012 respectively. The summary of the public consultation of November 2012 was published in April.

[3] The high-voltage tariff represents approximately 12% of residential customers' electricity bill excluding taxes.

- the drop in the annual annuity of the CRCP deducted from the expenses to be covered (for +3%) partially offset by the tariff developments resulting from the reconciliation of the CRCP during the TURPE 3 tariff period (for -2.3%)[4] ;
- these factors are partially offset by the drop in tariffs due to the increase in estimated auction income and the modification of their tariff treatment[5] (for -5.5%).

The differences between the tariff increases retained by CRE and those requested by RTE are mainly related to the following parameters:

- The non-consideration of RTE's requests concerning the terms for determining and setting the rate of return on assets: remuneration of a mid-year asset base mid-year, fixed assets under construction at the weighted average cost of capital and subsidised assets;
- revisions of estimates retained concerning certain expenses items, in particular purchases related to the grid losses, the interruptibility service, external purchases and taxes and duties.

The Higher Energy Council, consulted by CRE on the draft tariff decision, delivered its opinion on 21 February 2013.

[4] The tariff development of 1 August 2012 intended to reconcile a CRCP balance of €97.1 M in favour of RTE as specified in the deliberation of 24 May 2012.

[5] Elimination of the regulated account for the financing of interconnections (CRFI) and reconciliation of the balance resulting from TURPE 3 over the period (see sections C.2.3 and C.3.1).

Contents

COMMISSION
DE RÉGULATION
DE L'ÉNERGIE

A. Methodological principles

To establish the transmission tariffs, CRE first sets a projected tariff income.

It also defines a regulatory framework for limiting for certain predefined expense or income items the financial risk of the operator and/or user through clawback accounts, and also for encouraging the operator to improve its performance and promote market integration and the security of supply through the implementation of incentive mechanisms. The financial impact of these provisions is included either in the calculation for the projected tariff income or *ex post*.

The projected tariff income is broken down by user in the form of tariffs. There are several tariff components meeting different purposes. However, those that constitute the bulk of operator sales are withdrawal tariffs. These are composed of different coefficients; all these coefficient are referred as "tariff structure".

Taking into account all of these components serves to establish tariffs at their date of entry into force and the way in which they change each year.

<u>Definition of estimated tariff income</u>

CRE defines the operator's estimated tariff income for the period considered based on a business plan[6] submitted by the operator.

This projected tariff income is made up of capital expenses and net operating expenses as well as the impact of the clawback accounts.

$$RT_p = CNE_p + CC_p + A$$

Where:

- RT_p: Projected tariff income for the period;
- CNE_p: Projected net operating expenses for the period;
- CC_p: Projected capital expenses for the period;
- A: clearance of the clawback accounts for the period.

The projected capital charges include the return on and depreciation of the regulatory asset base (RAB). The RAB is determined based on the net book value of fixed assets, net of subsidies and contributions received from third parties.

$$\text{Projected capital charges} = \text{Projected depreciation} + \text{projected RAB} \times \text{WACC}$$

The method adopted to set the rate of return on assets is based on the weighted average cost of capital (WACC) using a normative financial structure. The operator's return should cover debt interest and a return on equity comparable to what investors could obtain for investments with similar risk levels. The cost of equity is estimated based on the capital asset pricing model (CAPM).

Net operating expenses include net running costs (mainly comprising external purchases, staff expenditure and taxes), and purchases related to the electricity system, net of non-tariff-related income (mainly comprising income from congestion management at interconnections).

The level of operating expenses retained is determined based on all of the costs necessary for a system operator's activity insofar as, pursuant to the law, these costs correspond to those of an efficient system operator. All of the projected data communicated by the operator is analysed thoroughly and corrected where necessary. In particular, with regard to net

[6] In the present case, RTE's business plan referred to the 2013 to 2016 period.

running costs, CRE endeavours to retain an operating expense trajectory integrating productivity efforts.

<u>Regulatory framework</u>

The operator's activity is regulated through different mechanisms constituting what is called the "regulatory framework".

First, the provisions of the regulatory framework enable the projected tariff income to be adjusted for inflation in order to protect the operator from inflation-related risks to which its expenses are exposed.

Second, for predefined items eligible for the expense and income clawback account (CRCP), the provisions of the regulatory framework make it possible to adjust, *a posteriori*, the tariff level to account for differences between projected and actual level of those items.

Lastly, in order to encourage the operator to efficiently manage the system, CRE has implemented incentive mechanisms. These provisions concern different fields of activity of the system operator: control of operating expenses, quality of supply to users, management of losses in the power system, interconnection development and the research and development activity. Some of these mechanisms are accompanied by financial incentives (in the form of positive or negative bonuses) which, according to the specific case, are added to or subtracted from the projected tariff income during the tariff period.

$$RT_N = RT'_p + E_{N-1} + I_{N-1}$$

Where:

- RT_N: Tariff income for the year N;
- RT'_p: Projected tariff income for the year N adjusted for actual inflation;
- E_{N-1}: Differences for the year N-1 charged to the CRCP balance;
- I_{N-1}: Incentives for the year N-1.

<u>Tariff structure</u>

Withdrawal tariffs are constructed in such a way as to encourage each user to adopt a consumption behaviour that minimises long-term system costs. The methodology for constructing tariffs also takes into account the provisions of Article L. 341-4 of the Energy Code which stipulates that tariffs are set in order to encourage clients to limit their consumption during periods when consumption of all customers is at its highest.

In order to do so, and based on the projected flow distribution data and projected consumption data provided by the operator, the methodology for establishing withdrawal tariffs is based on an analysis of the distribution of system costs among the different hours of the year and allocates these costs to users based on their respective consumption characteristics.

B. Tariffs' date of entry into force

The third set of tariffs for the use of public electricity systems (TURPE 3) entered into force on 1 August 2009 and applies until 31 July 2013.

The present tariffs are to apply as from 1 August 2013.

These tariffs are designed for a period of approximately four years.

C. Definition of projected tariff income

1. Capital expenses

Capital expenses include depreciations of and financial return on fixed assets. To calculate the capital expenses to be covered by the tariffs, CRE has retained the projected investment amounts presented by RTE. The rate of return on the regulatory asset base is maintained at 7.25%, nominal rate pre-tax.

1.1. Investment trajectory

CRE has retained the investment trajectory proposed by RTE:

In current €M	2013	2014	2015	2016
Investment trajectory	1,500	1,609	1,711	1,769

This trajectory includes a significant increase in investments in the public transmission system to accompany developments in the electricity system.
RTE estimates that the main needs are linked to the arrival of new production sources, the integration of European markets and the increase in interconnection capacity with neighbouring systems, improvement of supply quality and the safety and security of system operation.
This trajectory was analysed within the framework of the approval of RTE's annual investment programme (see CRE's deliberation of 4 December 2012 approving RTE's investment programme for 2013). The investment progression presented by RTE appears to be in line with supply and demand development perspectives.

1.2. Regulatory asset base

The regulatory asset base (RAB) valuation principles used since TURPE 2 have been renewed. Within the framework of TURPE 4, the value of the RAB is calculated from the net book value of assets, minus investment subsidies and income collected in advance from RTE's subsidiary Arteria, according to the principles outlined in CRE's deliberation of 7 December 2006 on the audit of the development of the optic fibre system and valuation of Arteria's high points for the 2005 fiscal year. Fixed assets benefiting from the legal revaluation of 1976 are incorporated in the RAB at their acquisition cost (excluding revaluation).

Conventionally, assets are incorporated into the RAB on 1 January of the year following their commissioning. The RAB increases with commissioned investments and decreases with depreciation of regulated assets covered by the tariffs.
In addition, the principle of remunerating fixed assets under construction at the cost of debt has been renewed. The rate of return retained for RTE's fixed assets under construction is equal to the cost of debt retained in the present deliberation (see section 1.3).
The projected trajectory retained for the RAB over the 2013-2016 period is as follows:

In current €M	2013	2014	2015	2016
Regulatory asset base	11,654	12,114	12,688	13,332

The projected trajectory retained for fixed assets under construction results from the investment trajectory retained and an estimated 18 month period before their commissioning.

1.3. The rate of return on assets

As for each new tariff, CRE has re-examined the different parameters used to calculate the WACC and the resulting range of values. It also:

- commissioned a study by an external consultant on the WACC for electricity and natural gas infrastructures. This study was carried out during the summer of 2011;
- carried out regular in-house assessments of the parameters of the WACC;
- held discussions with the operator which commissioned an external consultant to conduct a study on the analysis of the profitability of the electricity transmission activity;
- gave audience to the shareholder;
- took into account the developments in the tariff framework.

Within the framework of the present tariffs, CRE has retained the value of 7.25%, nominal pre-tax rate, using a range of values for each parameter included in the WACC formula. The estimates for each of these parameters are shown in the table below:

Nominal risk-free rate	4.0 %
Debt spread	0.6 %
Market premium	5.0 %
Asset beta	0.33
Equity beta	0.66
Leverage (debt/(debt + equity capital))	60 %
Corporate tax rate	34.43 %
Cost of debt (*)	4.6 %
Cost of equity (*)	11.2 %
Weighted average cost of capital (*)	**7.25 %**

*Nominal rate before tax

Compared to the values taken into account within the framework of TURPE 3, the main changes, in line with the evolution of macro-economic and financial data, cover:

- the drop in the nominal risk-free rate to 4.0%;
- the increase in the market risk premium to 5.0%.

CRE has maintained a normative approach to corporate tax. It has therefore maintained a reference rate of 34.43% in the calculation of the WACC.

1.4. Capital expenses

The trajectory retained for capital expenses is as follows:

In current €M	2013	2014	2015	2016
Return on assets in service	845	878	920	967
Return on fixed assets under construction	62	72	79	86

Depreciation covered by the tariff	661	696	728	772
Total capital expenses	**1,568**	**1,646**	**1,727**	**1,824**

2. Net operating expenses

Article L. 341-2 of the French Energy Code states that "*the tariffs for using the public transmission network and the public distribution networks shall be calculated 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 operator [...]*". Coverage of the actual costs incurred by the system operator also involves encouraging efficient use of the tariff-based resources allocated to them.

The operating expenses to be covered by the tariffs have been determined based on all operating costs required to run the public transmission system. To set the level of these expenses, CRE referred to the following in particular:

- the trajectory proposed by RTE for 2013-2016;
- the data from RTE's financial statements for the years 2009, 2010 and 2011 and estimated for 2012;
- the feedback on TURPE 3 and the results from analyses conducted by CRE on RTE's operating expenses for the years 2009 to 2016.

The average net operating expenses retained by CRE for RTE for the following tariff period amounts to €2,789 M. The average annual growth rate estimated for these net operating expenses between 2013 and 2016 is +1.4%.

In current €M	2013	2014	2015	2016
Net operating expenses	2,753	2,756	2,778	2,866
of which net running costs	*1,995*	*2,045*	*2,062*	*2,116*
of which costs related to the electrical system	*1,094*	*1,048*	*1,052*	*1,087*
of which non-tariff-related income	*-351*	*-351*	*-349*	*-350*
of which other expenses	*16*	*15*	*15*	*14*

Operating expenses have increased compared to the projected operating expenses used to establish TURPE 3. The main factors behind this increase, apart from inflation, are the regulatory and tax developments, the increase in staff expenditure, offset partially by a decrease in the average cost of losses and reinforcement costs.

2.1. Net running costs

Running costs are made up of other purchases and services, reinforcement costs, staff expenditure, taxes and duties and other operating expenses and income after deduction of capitalised production.

2.1.1. Other purchases and services

In current €M	2013	2014	2015	2016
Other purchases and services, excluding reinforcement	656	683	708	725

The main factors behind the increase in the “Other purchases and services” item are related to new expenses compared to the previous tariff period and the increase in operating assets which generate increased expenses.

The “Other purchases and services” item incorporates costs resulting from the implementation within RTE of a new asset management policy. This consists in moving from assessing the technical condition of each piece of equipment and the risk of obsolescence to assessing equipment components. Renewal, maintenance and restoration operations on these equipment components are recorded as operating expenses. This approach consequently leads to overcosts in terms of operating expenses offset by low increases expected for replacement investments. In the long term, the amount of renewal expenses and the associated operating expenses for the 2011-2030 period that result from this new asset management policy should be less than the amount that would be obtained if the previous asset management policy was maintained. The total cost of this new asset management policy is approximately €30 M on average per year over the TURPE 4 period.

RTE has also taken into account new expenses to cover mainly repair work due to the increase in copper theft, the increase in the volume of expenditure earmarked for damage and maintenance expenses following the purchase of the SNCF's high-voltage network effective since 1 May 2010. The total cost of these expenses is approximately €24 M on average per year over the TURPE 4 period.

RTE requested that a risk of unplanned expenses over the next tariff period be taken into account on the basis of its experience over the TURPE 3 period (in particular unforeseen taxes and the impact of extraordinary climatic events). Since this type of risk is to be assessed by the WACC in the current tariff framework, CRE has not accepted this request. Therefore, it revised downwards by €12.5 M on average per year the trajectory requested by the operator over the 2013-2016 period.

In addition, CRE analysed the productivity efforts proposed by RTE for the "Other purchases and services" item restated for the scope developments described above. The results of this analysis are presented in section C.2.1.5.

In current €M	2013	2014	2015	2016
Adjustments retained by CRE	5	10	15	20

2.1.2. Expenses related to the mechanical reinforcement programme for the public transmission grid

In current €M	2013	2014	2015	2016
Expenses related to the reinforcement programme	196	173	123	101

Following the storms in 1999, RTE implemented, instructed by the government, a mechanical reinforcement programme for the public transmission grid amounting to €1.7 billion to be completed in 2017.

The development of European standards on dimensioning overhead lines, feedback from storm Klaus, probabilistic analyses of the effects of wind on equipment led to, in 2010, a change in the technical reference framework for the mechanical reinforcement policy in agreement with the Directorate-General for Energy and Climate. These new technical provisions enable RTE to optimise the work to be performed and decrease the volume of annual expenditure.

2.1.3. Staff expenditure

RTE's estimates for the increase in staff and emoluments have been retained in the net operating expenses trajectory for the 2013-2016 period. The staff expenditure item represents an average €850 M per year over the TURPE 4 period, an increase compared to the TURPE 3 period, due in particular to:

- the need for additional staff as a result of new activities (internalisation and development of R&D, regulatory developments, deployment of a training mechanism) which has led to an average increase of €12 M per year over the period;
- the consideration of increases in social contributions (increase in employer contributions, increase in the social security contributions rate and widening of their calculation basis) which lead to overcosts for the operator totalling approximately €24 M on average per year over the period.

In addition, CRE analysed the productivity efforts proposed by RTE in terms of staff restated for the scope of developments described above. The results of this analysis are presented in section C.2.1.5.

2.1.4. Taxes

In current €M	2013	2014	2015	2016
Taxes	478	502	525	550

This item is made up mainly of the pylon tax, the flat-rate tax on network businesses (IFER), the local business tax (*contribution économique territorial - CET*) and the property tax. Since 2011, this item has tended to increase by about +4.5% each year (i.e. +€37 M between 2011 and 2013) and approximately +5% on average per year over the TURPE 4 period.
RTE requested that an annual increase of +4% be considered for the IFER rate. Due to the lack of elements to justify this regulatory development taken into account by RTE, CRE has not fulfilled this request. It revised downwards the trajectory for this item for the 2013-2016 period by approximately €5 M on average per year.

In current €M	2013	2014	2015	2016
Adjustments retained by CRE	2	4	6	8

2.1.5. Productivity objectives

Articles L.341-3 of the Energy Code defines the incentive regulation principles to encourage operators to improve their performance particularly by making efforts towards productivity.

Within this framework, CRE has thoroughly analysed the trajectory of RTE’s net operating expenses from the actual expenses in 2011, the last year for which definitive results were available, to the estimates for the 2012-2016 period.

To apply this productivity objective, CRE first distinguished:

- (1) “new” expenses compared to those taken into account within the framework of TURPE 3 (mainly expenses related to new regulatory constraints, additional staff owing to RTE’s new activities, developments in social contribution rates and rules governing their base).
- (2) the specific expense items for which application of a productivity objective is not relevant. These items correspond mainly to tax expenses, reinforcement expenses and other expenses and income (such as insurance, the preferential tariff for active and retired employees, and the income from penalties billed by RTE within the framework of system service contracts and the adjustment mechanism).

The analysis of these expenses is broken down in the relevant sections above (sections C.2.1.1. to C.2.1.4.). Where necessary, CRE adjusted the level of expenses to be covered requested by the operator under these expenses, but it considers that it is not relevant to apply a productivity objective to this type of expenses.

RTE’s other running costs are considered to fall under an identical scope of activity (3) compared to the TURPE 3 period. This scope comprises mainly “Other purchases and services” expenses and “Staff expenditure”. CRE considers that for the portion relating to this identical scope of activity, the trajectory for net running expenses retained must incorporate productivity efforts.

The details for the calculation of the identical scope of activity used by CRE to conduct its analysis are presented below:

In current €M	2011	2013	2014	2015	2016
Total net running costs – RTE's request	**1,855**	**2,006**	**2,062**	**2,092**	**2,152**
- New costs (1)	**-9**	**-83**	**-111**	**-128**	**-148**
of which other purchases - Section C.2.1.1.	*-9*	*-50*	*-76*	*-91*	*-109*
of which staff expenditure (new staff and new social contributions) - Section C.2.1.3.	*0*	*-33*	*-35*	*-37*	*-39*
- Other specific items (2)	**-778**	**-813**	**-816**	**-801**	**-813**
of which taxes - Section C.2.1.4.	*-441*	*-480*	*-505*	*-532*	*-558*
of which reinforcement expenses - Section C.2.1.2.	*-196*	*-196*	*-173*	*-123*	*-101*
of which other income and expenses	*-141*	*-138*	*-138*	*-147*	*-154*
Total expenses under identical scope of activity (3)	**1,067**	**1,111**	**1,135**	**1,163**	**1,190**
other purchases and services (4)	*443*	*465*	*468*	*478*	*481*
including staff expenditure (5)	*624*	*646*	*667*	*685*	*709*

CRE's analysis

With regard to the "Other purchases and services" item (4), the level requested by RTE for an identical scope of activity increased by +1.7%, i.e. "inflation - 0.3%" on average over the 2011-2016 period. CRE observed that this increase is lower than inflation. However, the productivity objective taken into account by the operator is lower than the increase observed in these expenses for the years 2009-2012 (+0.1%, i.e. "inflation - 1.5%" on average per year over the period). RTE highlighted that only a limited residual productivity gain remained for this item after the results of actions already undertaken in the past had been taken into account. While acknowledging these justifications, CRE considers that an additional productivity objective must be incorporated into the projected trajectory for this item proposed by RTE. To set the level of operating expenses for the "Other purchases and services" item over the 2013-2016 period, CRE has retained a trajectory corresponding to an annual percentage change equal to inflation between 2011 and 2013, then "inflation - 1%" between 2013 and 2016. Consequently, it has revised downwards by an average €6 M per year RTE's request over the 2013-2016 period.

For the "Staff expenditure" item (5), CRE analysed the staff trajectory proposed by RTE, excluding the increase in staff due to new activities since 2011. On this like-for-like basis, CRE has observed that the average change in this item is -0.3% per year over the 2013-2016 period. This trend has followed a continuous downward trajectory of -0.3% per year on average since 2005 within an identical scope of activity. CRE has retained the trajectory proposed by RTE.

As a result:

- the level of net running costs, after incorporation of an additional productivity effort retained by CRE increases by €140 M between 2011 and 2013, and then by €40 M per year on average for the 2013-2016 period:

In current €M	2011	2013	2014	2015	2016
Total net running costs – RTE's request	**1,855**	**2,006**	**2,062**	**2,092**	**2,152**
Adjustments made by CRE outlined in		-7	-14	-21	-28

sections C.2.1.1 to C.2.1.4					
Additional productivity efforts within the identical scope of activity retained by CRE		-5	-4	-9	-7
Total net running expenses retained by CRE	**1,855**	**1,995**	**2,045**	**2,062**	**2,116**

- the projected level of net running expenses on a like-for-like scope totals €1,106 M in 2013, up €39 M compared to actual expenses in 2011. The level of this scope increases afterwards by an average €26 M per year for the 2013-2016 period;
- the projected level of net running expenses outside the like-for-like scope amounts to €889 M in 2013, up €101 M compared to actual expenses in 2011. This increase is mainly due to the new expenses in the “other purchases and services” item in the amount of €37 M (described in section C.2.1.1), the increase in taxes in the amount of €37 M (described in section C.2.1.4), and the new expenses in the “staff expenditure” item in the amount of €32 M (described in section C.2.1.3).

2.2. Expenses related to the electricity system

2.2.1. Costs related to compensation for losses in the grid

Pursuant to the provisions of Article L. 321-11 of the Energy Code, RTE freely negotiates with producers and providers of its choice contracts enabling coverage of losses, according to competitive, non-discriminatory and transparent procedures such as public consultations and organised markets.

The implementation of regulated access to historic nuclear power (ARENH) for loss compensation, introduced by Article L. 336-1 of the Energy Code and specified by the provisions of Decree No. 2011-466 of 28 April 2011, offers RTE a new possibility to purchase the energy required for loss compensation. This new mechanism reduces by roughly 18% the average unit cost for loss compensation over the 2013-2016 period.

CRE analysed the trajectory for the cost of losses proposed by RTE and made adjustments on that basis compared to the operator’s request:

- downward revision of the trajectory for the increase in the price of ARENH;
- consideration of the Order of 19 November 2012 amending the Order of 25 November 2011 setting the timetable for the opening-up of rights of access to ARENH for losses;
- consideration of a projection of cost for the capacity guarantee which will be incurred by the providers of losses for winter 2015-2016 in accordance with Decree No. 2012-1405 of 14 December 2012.

All of these adjustments represent an average decrease in the “Purchase of loss” item by €23 M per year over the TURPE 4 period compared to RTE’s request.

The projected volume of energy loss and expenses related to the compensation of this loss retained by CRE for the 2013-2016 period is as follows:

	2013	2014	2015	2016
Volume (TWh)	11.5	11.8	11.8	11.9
Cost (current €M)	677	607	607	632

2.2.2. System services

The present tariffs cover the costs related:

- to the constitution of primary and secondary reserves for frequency-active power control;
- to the constitution of primary and secondary reserves for voltage-reactive power control;
- adjustments for the reconstitution of system services;
- synchronous compensation.

CRE analysed the system services expenses proposed by RTE. The price increase is in line with the price indexation of the system services participation contract model. CRE has retained the trajectory proposed by RTE:

In current €M	2013	2014	2015	2016
Frequency control	206	211	217	224
Voltage control	125	127	129	132
Total cost	**331**	**338**	**346**	**356**

2.2.3. Other expenses related to the operation of the electricity system

The current tariffs cover the costs related to congestions, contracts for exchanges between transmission system operators, the inter-transmission system operator compensation mechanism (ITC) and the interruptibility service.

CRE analysed the trajectory for projected expenses proposed by RTE and on that basis, adjusted the expense trajectory related to the interruptibility service:

- consideration of the Order of 10 December 2012 pursuant to Article L. 321-19 of the Energy Code setting in particular the remuneration terms for the interruptibility mechanism;
- consideration of the time required for implementing the interruptibility service which will generate expenses from the year 2014.

These adjustments are reflected by an average drop in the "Other expenses related to the operation of the electricity system" item by €11 M per year over the TURPE 4 period compared to RTE's request.

For the 2013-2016 period, the projected trajectory for expenses related to system purchases apart from losses and system services retained to define the tariff level is as follows:

In current €M	2013	2014	2015	2016
Other expenses related to the operation of the electricity system	86	102	99	100

2.3. Non-tariff-related income

The forecasts for income received independently of the system user tariffs are deducted from the projected operating income to be covered by the tariffs. For RTE, this concerns mainly the income related to the mechanisms for managing congestion at interconnections. CRE commissioned a study by an external consultant to assess the trajectory of income related to the mechanism for managing congestion at interconnections. The trajectory proposed by RTE is in line with the results of this study.

Therefore, CRE has retained the projected trajectory for non-tariff-related income proposed by RTE:

In current €M	2013	2014	2015	2016
Non-tariff-related income	351	351	349	350
of which income related to the mechanisms for managing congestion at interconnections	*280*	*280*	*280*	*281*

3. Adjustment accounts

3.1. Reconciliation of the regulated account for the financing of interconnections

The regulated account for the financing of interconnections (CRFI) is a specific account set up within the framework of TURPE 3. The goal of this mechanism was to use a portion of the income related to the allocation of interconnection capacity to finance investments aimed at maintaining or increasing interconnection capacity as proposed by Article 16 of European Regulation (EC) No. 714/2009 of 13 July 2009. The total amount of auction income allocated under TURPE 3 to finance interconnections was €202.9 M.

In order to avoid remunerating twice assets financed by auction income and included in the RAB, TURPE 3 made provisions to reduce the expenses to be covered by the tariffs by an annuity equal to the capital expenses corresponding to these assets. This annuity was equal to the remuneration of the stock of the CRFI at the beginning of the year and its depreciation on the basis of a 40-year normative duration.

Within the framework of TURPE 4, all auction income will be deducted from the tariffs (see section D.3). A mechanism for the annual follow-up of investments aimed at maintaining or increasing interconnection capacity, described in section D.3 has been implemented.

At the end of the year 2012, following allocations and depreciation under TURPE 3, the balance of the regulated account for the financing of interconnections (CRFI) was €194 M in favour of users. Since this mechanism has been terminated, this balance, initially intended to be recovered over 40 years, will be completely cleared over the TURPE 4 period.

The discount rate retained for this purpose is the risk-free rate set for the TURPE 4 period (see section 1.3). The four-year annuity resulting from this balance is €54 M in favour of users. It will be deducted from the expenses to be covered.

3.2. Clearance of the expense and income clawback account for previous tariff periods

TURPE 3 provided for the clearance of the CRCP balance under TURPE 2 over five years. At the end of 2012, the non-reconciled balance of the CRCP of TURPE 2 was €306 M in favour of users. The CRCP balance under TURPE 2 is due mainly to income related to the mechanisms for managing congestion at interconnections that was considerably higher than forecasts and to the absence of clearance over the TURPE 2 period.

As from the TURPE 3 period, an annual CRCP clearance mechanism was set up. This method enabled to clear of differences between projected and actual expenditures / income on a more regular basis. Given the balances for the years 2009, 2010 and 2011 and projections established mid-2012 for the year 2012, the TURPE 3 CRCP amounted to -€0.6 M at the end of 2012 in favour of RTE.

As provided for under TURPE 3, the amounts resulting from the application of incentive mechanisms pertaining to controllable operating expenses, the loss purchase cost and the continuity of supply are posted to the CRCP balance at the end of the tariff period. End 2012, the balance of the CRCP Incentives was €5 M in favour of users.

In current €M	2009	2010	2011
Controllable operating expenses	0.0	0.0	3.0
Loss purchase cost	-0.5	-1.0	-2.4
Supply continuity	8.3	4.2	-7.5
Total (excluding remuneration)	**7.8**	**3.2**	**-6.9**
Remuneration	1.0	0.3	-0.3
Total	**8.8**	**3.5**	**-7.2**

As at 31 December 2012 and according to the projections established mid-2012, RTE's CRCP balance breaks down as follows (in €M):

TURPE 2 CRCP	306
TURPE 3 CRCP	-1
CRCP Incentives	5
Commitments at end 2012	**311**

The TURPE 3 CRCP balance is based on estimates from 2012 data. A definitive calculation of the TURPE 3 CRCP balance will be carried out as soon as the final data is known and taken into account in the annual adjustment for 2014.
The CRCP balance will be completely cleared over the TURPE 4 period. The discount rate retained for clearance is the risk-free rate set for the TURPE 4 period (see section 1.30).
The four-year annuity resulting from this balance is €82 M in favour of users. It will be deducted from the expenses to be covered.

4. *Projected tariff income*

The level of expenses to be covered by the tariffs is as follows:

In current €M	2013	2014	2015	2016
Net operating expenses	2,753	2,756	2,778	2,866
Capital expenses	1,568	1,646	1,727	1,824
CRCP annuity	-82	-82	-82	-82
CRFI annuity	-54	-54	-54	-54
Expenses to be recovered	**4,185**	**4,266**	**4,369**	**4,555**

D. Regulatory framework

1. *Annual tariff increase*

From 2014, the tariffs will be mechanically adjusted on 1 August each year using the following percentage:

$$Z_N = IPC_N + K_N$$

Z_N: percentage of change, rounded off to the nearest tenth of a percent, in the tariff scale in application as from 1 August of the year *N* compared to that in application the previous month.

COMMISSION DE RÉGULATION DE L'ÉNERGIE

IPC_N: percentage of change between the average value of the consumer price index excluding tobacco over the calendar year *N-1* and the average value of the same index over the calendar year *N-2*, as published by the French statistics agency INSEE (identifier: 000641194).
K_N: CRCP reconciliation factor for year *N*, calculated on the basis of the CRCP balance as at 31 December of year *N-1* and reconciliations already conducted. The absolute value of the coefficient K_N is limited to 2%.

2. Expense and income clawback account

2.1. Principles

Given the four-year validity of the tariffs, CRE has based the present tariff deliberation on estimates of short- and medium-term trends in expenses and income.
For some categories of expenses and income that are hard to predict or control, CRE has renewed the expense and income clawback account (CRCP) mechanism, set up under TURPE 2, to measure and offset, for previously identified items, the differences between projected and actual expenses and income on which the present tariffs are based.
The CRCP is also the vehicle used for financial incentives resulting from the application of incentive regulation mechanisms.
The CRCP is the account to which is posted, where relevant, RTE's surplus earnings and shortfalls. It is reconciled by adjusting the tariff scale during the annual change in tariffs. The contribution of CRCP reconciliation to the annual variation of the tariff scale is limited to +/-2%.

2.2. Scope

The expense and income items covered by the mechanism are as follows:

- the expenses related to compensation for losses on the grids;
- certain expenses related to interconnection management, namely international congestion costs and net outsourced costs related to management fees for interconnection capacity allocation mechanisms, provided they can be audited;
- expenses related to the net book value of decommissioned fixed assets;
- income received for all tariff components according to the terms stated hereinafter;
- income related to congestion management mechanisms at transmission grid interconnections with neighbouring countries. This income is net of all compensation paid by RTE in the event of a reduction in interconnection capacity;
- income related to contracts between TSOs;
- financial incentives related to the various incentive-based regulation mechanisms;
- R&D operating expenses (according to the terms provided in section D.4.3.1);
- capital expenses.

In addition, the results of audits conducted by CRE will be taken into account within the scope of the CRCP.

2.3. Operating rules

For each item considered eligible for the CRCP, differences are calculated according to the rules stated below.

1. For each expense or revenue item considered, excluding income received for all pricing components, differences posted in the CRCP are calculated on the basis of a comparison between the reference value of forecast annual expenses or income and the actual amounts of these expenses or income for each year of the tariff period.

   As the tariff scale is indexed to the consumer price index (CPI), excluding tobacco, RTE is covered from the risk of inflation for all its expenses. However, changes in expense items covered by the CRCP mechanism, such as the compensation of energy losses on the grids or capital expenses, are not necessarily related to CPI trends. To correct this, CRE has adapted the reference values used to calculate the CRCP balance.

   These reference values, required for the calculation of the CRCP for year *N*, are therefore calculated on the basis of provisional values in 2013 constant Euros and are revaluated annually according to the CPI adopted for the calculation of the tariff scale of year *N* and previous years.

   The provisional values, in 2013 constant Euros, for the various items of operating and capital expenses, are set below:

In €M_{2013}	2013	2014	2015	2016
Expenses related to compensation for losses on the grids	677	597	584	596
International congestion costs	3	3	3	3
Net outsourced expenses related to management fees for interconnection capacity allocation mechanisms	3	3	3	3
Net book value of decommissioned fixed assets	24	23	23	22
Operating expenses	**706**	**626**	**613**	**624**
Income related to the mechanisms for managing congestion at interconnections	280	275	270	265
Income related to contracts between TSOs	0	0	0	0
Operating income	**280**	**275**	**270**	**265**
Capital expenses	**1,568**	**1,617**	**1,663**	**1,722**

2. As regards income received for all pricing components, the tariff income for the year *N* is compared to the projected tariff income adjusted for actual inflation and the CRCP amounts reconciled in year *N*. RTE is thus covered against the risk related to uncertainties in the forecasts for volumes transmitted.

In current €M	2013	2014	2015	2016
Projected tariff income	4,182	4,297	4,397	4,495

3. As regards expenses related to losses compensation, the difference in costs for year *N* between the projected value of the loss purchase cost and the costs actually borne by RTE will be posted to the CRCP in full, excluding the following exceptions:

   - these costs do not cover any premiums paid by RTE for an options ceiling price;

- any excess costs resulting from the reconstitution of RTE's portfolio will be offset via the CRCP: in full for force majeure events or supplier insolvency and 50% for events qualified as circumstances considered as force majeure in contracts;
- if the annual volume of imbalances attributed to RTE's balancing scope (differences between the volume of losses actually recorded, following the process for calculating imbalances and the hourly estimate) is greater than 8% of the volume of recorded losses, an audit will be conducted by CRE to ensure that the causes of the increase in the volume of imbalances could not be controlled. If, following this audit, it is considered that the increase in the volume of imbalances could have been avoided, the difference in expenses related to loss compensation will only take into account the expenses up to the limit of 8% for RTE of the volume of recorded losses.

4. The financial incentives for each of the incentive-based mechanisms will be calculated as stated in the corresponding sections and posted each year to the CRCP balance.

5. In order to ensure the mechanism's financial neutrality, the discounted CRCP balance, for imbalances recorded over the period of application for the present tariffs, is calculated annually using an interest rate equivalent to the risk-free rate adopted within the framework of the present deliberation.

6. The CRCP balance calculated for calendar year *N* is reconciled in part or in full as of the following year. The impact of the annual reconciliation of the CRCP on the development of the tariff scale cannot be higher, in absolute value, than 2%. Where relevant, the amounts not reconciled because of this limit are posted to the CRCP balance to be reconciled the following year.

7. RTE will send the amounts required for the calculation of the CRCP of year *N* to CRE three months before the tariff change at the latest.

3. Regulated account for the financing of interconnections

As stated in section C.3.1, the regulated account for the financing of interconnections (CRFI) is a specific account set up within the framework of TURPE 3. The goal of this mechanism was to use a portion of the income related to the allocation of interconnection capacity to finance investments aimed at maintaining or increasing interconnection capacity pursuant to Article 16 of European Regulation (EC) No. 714/2009 of 13 July 2009.

Since the CRFI is a non-accounting account, the sums posted to it were not deducted from the operator's profit and were therefore subject to corporate tax and the deduction of dividends. The amount available for financing interconnection investments was reduced accordingly.

This mechanism failed to efficiently allocate financial resources for interconnections. The choice was therefore made, over the TURPE 4 period, to deduct all auction income from expenses to be covered.

In order to comply with Article 16 of EC Regulation No. 714/2009 of 13 July 2009, an annual follow-up of investments contributing to maintaining or increasing capacity will be performed. It will ensure that, over the tariff period, the level of investments contributing to maintaining or increasing exchange capacity is in line with auction income received. RTE will have to provide, within the framework of the report on the implementation of its annual investment programme, quantitative and qualitative elements justifying projects' contribution to cross-border exchanges.

4. Incentive regulation

4.1. Operating expenses

The trajectory of RTE's net operating expenses is defined for the 2013-2016 period (see section C.2). It incorporates a productivity objective related to net running expenses on the basis of an identical scope of activity compared to the previous tariff period.
The regulatory framework of TURPE 3 made provisions for an asymmetrical system in which RTE conserved 50% of the productivity gains made compared to the trajectory set and bore 100% of the productivity losses. For the TURPE 4 period, CRE has adopted a symmetrical system in which RTE conserves 100% of additional productivity gains and losses. CRE thus hopes to further encourage RTE to control its costs.

4.2. Interconnection investments

Article 37 of European Directive 2009/72/EC of 13 July 2009 as well as Article L. 341-3 of the French Energy Code state that CRE may introduce appropriate short-term or long-term incentive measures to encourage transmission and distribution system operators to promote integration of the internal market in electricity.
The development of new infrastructure improving cross-border exchange capacity is one of the conditions for the emergence of an integrated European energy market. Interconnections also enable optimisation of the resources in the electricity system at a time when there is a strong development in the production of electricity from intermittent energy sources. Lastly, interconnections contribute to the consolidation of supply security.
Interconnection projects require, among other things, specific efforts from RTE, in particular to overcome difficulties related to coordination with its counterparts in neighbouring countries, administrative authorisations, local acceptance of works and the technical challenges involved with natural obstacles.
CRE carried out several studies to assess the relevance and feasibility of an incentive mechanism for interconnection development based on the assessment of the usefulness of the project. In addition, CRE consulted stakeholders about the value of such an incentive and on the mechanism envisaged.
The present deliberation introduces a regulatory framework aimed at encouraging RTE to develop interconnections. The incentive mechanism thus created is in line with the guidelines forwarded by the Minister of Ecology, Sustainable Development and Energy, by contributing to the development of exchange capacity at borders, in agreement with national and European prospects for system development.
The incentive mechanism is based on the assessment of the value of new interconnection infrastructure for the European electricity system and aims to:

- stimulate interconnection projects that are useful for the community;
- encourage RTE to carry out investments under the best cost and time conditions;
- encourage RTE to properly operate newly created interconnectors, in particular with regard to the additional trade flows brought by the structure.

RTE will provide to CRE, at least seven months before the investment decision, the elements enabling the assessment of the value of the interconnection that it plans to build. CRE will examine the elements and decide, where relevant to grant incentives and will set detailed calculation terms in an *ad hoc* tariff decision.

The financial incentive for interconnection investments will take the form of a fixed annual bonus in euros, defined ahead of the investment decision depending on the value of the interconnection for the community.

Incentives to minimise costs and time required to complete interconnections, as well as the incentive to properly manage them, will take the form of variable bonuses that will be added every year to the fixed annual bonus. The parameters used to calculate these bonuses will be defined in CRE's *ad hoc* tariff decision for each project.

4.2.1. Management of bonuses and payout terms

The bonus amounts will be set in compliance with the following principles:

- the sum of annual bonuses will be positive or zero;
- the bonus relating to costs may, if it is positive, be fully kept by RTE independently of the level of the other bonuses, which increases RTE's incentive to control costs;
- the sum of annual bonuses (fixed and variable) will be limited depending on the value of the interconnection for the community and the investment cost.

Since the incentive is positive, RTE is guaranteed to receive a payout that is at least equal to the applicable WACC. The incentive mechanism therefore does not introduce any additional risk for RTE.

All bonuses will be paid to RTE after the commissioning of the interconnection, for a maximum duration of ten years, by crediting RTE's CRCP.

The calculation terms for the different bonuses are described in the following sections.

4.2.2. Incentive calculation method

a) Incentive for carrying out investments useful to the community

The level of fixed bonus granted to RTE will be determined by taking into account the value of the interconnection for the European electricity system, which will include quantifiable elements, but also qualitative elements such as the security of supply.

The component quantifying the usefulness of the interconnection for the electricity system will be assessed taking into account in particular:

- a yearly estimation of additional trade flows generated by the interconnection;
- a forecast of market prices in the two interconnected countries after the commissioning of the interconnection;
- an estimation of investment costs.

This assessment will be taken into account as an indication of the value created by the project for the community, a fraction of which will constitute the incentive granted to RTE.

When deemed relevant, the usefulness of the interconnection may be assessed by taking into account the borders between France and several countries. These same borders will be used to calculate the variable bonus related to flows.

b) Incentive for carrying out investments at the best cost

RTE will give CRE its best estimate of the investment costs for the given interconnection project. RTE will receive its bonus after the interconnection has been commissioned. The lower the costs the higher the bonus and the higher the costs the lower the bonus. The bonus related to costs will depend on the difference between the forecast and actual budget, and will reflect the gain variation for the community as a result of the variation in the investment costs.

If RTE were to obtain a subsidy from the European Commission for an interconnection investment, this subsidy would be taken into account in RTE's performance calculation, being deducted from actual expenses.

c) Incentive for optimal operation of the interconnection

Once the interconnection is commissioned, the trade flows it creates will be compared to the flows announced by RTE before the investment decision for the year in question. The bonus will depend, similarly to the bonus relating to costs, on the variation in usefulness for the community as a result of a variation in trade flows. The more the actual trade flows exceed the trade flows forecast by RTE, the greater the bonus.

d) Incentive for carrying out investments within the shortest possible time period

Since RTE's capital cost is already covered by the return on the RAB at the WACC, financial incentives will constitute an economic benefit for RTE. The sooner RTE manages to obtain the financial incentives, the higher their value. The incentive for carrying out investments within the shortest possible time period is therefore implicit since the fixed bonus and bonuses related to costs and flows is paid when the interconnection is commissioned.

4.3. Research and development

The present decision introduces a mechanism aimed at providing RTE with the means to carry out R&D and innovation projects required for the construction of the electricity systems of tomorrow by guaranteeing in particular the absence of tariff obstacles to undertaking R&D projects or making innovative investments. It also sets up a follow-up mechanism aimed at giving stakeholders in the electricity sector greater visibility into the R&D projects carried out by RTE.

4.3.1. Tariff treatment of R&D expenses

RTE presented, for the 2013-2016 period, the following R&D expenses trajectory:

In current €M	2013	2014	2015	2016	Total
R&D expenses	23.7	25.6	28.6	30.7	**108.6**

CRE will review, at the end of the tariff period, the sums actually spent by RTE and will return to users, via the CRCP mechanism, the difference between the projected and actual trajectory. Any annual differences between the actual and projected trajectory will have to be justified by RTE within the framework of the annual report sent to CRE.

4.3.2. Developing visibility into RTE's R&D programme

Within the framework of TURPE 4, CRE has introduced a follow-up of R&D projects. This follow-up will take the form of a report, sent by RTE to CRE before the end of the first quarter of each calendar year, for the previous year including in particular the following elements:

- a description of the projects carried out with the associated expenses and results obtained;
- a list of projects in progress and future projects with the expected outcomes;
- the expenses for the past year;
- the forecast expenses for each year until the end of the tariff period;
- the number of full-time equivalents associated with R&D programmes.

In addition, every two years, CRE will publish a report on RTE's innovation and R&D policy. This report will complete the communication tools already set up by CRE, in particular in the field of smart grids. It is aimed at giving stakeholders in the electricity sector visibility into the research and innovation policy led by RTE and financed by TURPE. The first report will cover the years 2013 and 2014.
A description of RTE's R&D programmes is annexed hereto.

4.4. Quality of supply

Article L. 341-3 of the French Energy Code states that CRE "*may propose [...] appropriate short- or long-term incentives to encourage transmission and distribution network operators to improve their performance particularly as regards the quality of the electricity* [...]".
To do so, CRE has renewed and reinforced the incentive mechanism for quality of supply implemented within the framework of TURPE 3.
The reinforcement of the incentive measures is based on:

- an extension of the scope of incentives to include the average frequency of power cuts;
- increase in incentive limits.

CRE has decided to maintain high standards for the reference average duration of power cuts by renewing the value of 2.4 minutes adopted under TURPE 3.
The parameters for incentives related to the average duration of power cuts and the average frequency of power cuts correspond to 50% of the values used for system planning (€26/kWh and €3/kW respectively). These elements have resulted in an incentive for the average duration of power cuts amounting to €10.4 M/minute (compared to €9.6 M/minute under the previous tariffs) and an incentive for the average frequency of power cuts totalling €72.0 M/power cut.
The incentive limit is set at €30 M in line with the incentive parameters.
Notwithstanding the provisions of the present section, RTE may be led to communicate to CRE other indicators of the quality of the public transmission system, in particular within the framework of RTE's activity report. Moreover, RTE may also send to stakeholders concerned and in particular to grid users, indicators of the quality of the public transmission system.

4.4.1. Parameters of the incentive scheme

The average duration of power cuts and the average frequency of power cuts are calculated for power-consuming installations and public distribution networks directly connected to the public transmission grid.

The average duration of power cuts for the year *N* (DMC_N), expressed in minutes, is calculated using the following formula:

$$DMC_N = \frac{Total\ END\ of\ \ year\ N \times 60}{PMDA\ (excluding\ losses)\ of\ \ year\ N}$$

END: Undistributed energy, expressed in MWh. Undistributed energy is determined excluding incidents following exceptional events (see definition below). The calculation of undistributed energy includes load shedding for reasons related to the public transmission grid.
PMDA: average annual distributed power, expressed in MW. PMDA is obtained by dividing the value of energy (excluding losses) distributed in the year by 8,760 hours (or 8,784 hours if year *N* is a leap year).

The average frequency of power cuts for the year N (FMC_N), expressed as the number of power cuts, is calculated using the following formula:

$$FMC_N = \frac{Number\ of\ long\ and\ short\ power\ cuts\ for\ year\ N}{Number\ of\ \text{installations}\ as\ at\ 31\ December\ of\ year\ N}$$

Long power cut: cut in an installation's power supply for more than 3 minutes.

Short power cut: cut in an installation's power supply for between 1 second and 3 minutes. The number of long and short power cuts is determined excluding incidents following exceptional events (see definition below).

The level of financial incentive for year N is calculated using the following formula:

$$I_N = 10{,}4 \times DMC_{réf} \times \ln\left(\frac{DMC_N}{DMC_{réf}}\right) + 72{,}0 \times FMC_{réf} \times \ln\left(\frac{FMC_N}{FMC_{réf}}\right)$$

I_N: financial incentive for year N, expressed in €M, which may result in negative values. The absolute value of annual incentive I_N is limited to €30 M.
$DMC_{réf}$: reference average annual duration of power cuts, expressed in minutes. This value is set at 2.4 mins for the entire duration of the tariff period.
$FMC_{réf}$: reference average annual frequency of power cuts, expressed in the number of power cuts. This value is set at 0.6 for the entire duration of the tariff period.

4.4.2. Follow-up of quality of supply

Before the end of each calendar quarter, RTE must provide CRE with the following information on the previous quarter:

- energy not distributed (for all reasons);
- energy not distributed excluding exceptional events;
- energy not distributed during load shedding;
- energy not distributed during load shedding for reasons related to the public transmission grid;
- the number of long and short power cuts (for all reasons);
- the number of long and short power cuts excluding exceptional events;
- for each exceptional event: all factors justifying the exceptional nature of the event, the energy not distributed, the number of long and short power cuts during the event and all factors demonstrating how quickly RTE took measures to restore normal operating conditions and the relevance of those measures.

Before the end of first quarter of each year, RTE must provide CRE with the following information on the previous year:

- the annual average duration of power cuts (for all reasons);
- the annual average duration of power cuts excluding exceptional events;
- the annual average duration of power cuts following load shedding;
- the annual average duration of power cuts following load shedding for reasons related to the public transmission grid;
- the annual average frequency of power cuts (for all reasons);
- the annual average frequency of power cuts excluding exceptional events.

4.4.3. Exceptional events

Under the incentive regulation for supply continuity, the following are considered to be exceptional events:

- destruction due to war, riots, looting, sabotage, attacks, criminal acts;
- damage caused by accidents and events that cannot be controlled, caused by third parties, such as fires, explosions and plane crashes;
- natural disasters defined by the amended French law No. 82-600 dated 13 July 1982;
- sudden, unplanned and simultaneous unavailability of several production facilities connected to the public transmission grid, if unavailable power is greater than the provisions of the security regulations stipulated in Article 28 of the standard public electricity transmission grid franchise specifications (appended to French Order No. 2006-1731 dated 23 December 2006);
- disconnection of structures decided by public authorities on the grounds of public or police safety if this decision is not due to the actions or inaction of the public electricity system operator;
- atmospheric phenomena of an exceptional nature with regard to their impact on the grids, characterised by an annual probability of incidence of less than 5% for the given geographical area when at least 100,000 final users supplied by the public transmission and/or distribution grids go without electricity in one day and for the same reason.

4.5. Grid losses

In order to contain expenses to cover losses in the public transmission grid, an incentive regulation mechanism related to the purchase price of losses was introduced within the framework of TURPE 3. The mechanism for regulated access to historic nuclear power (ARENH) undermines the relevance of this incentive mechanism since, as from 2014, RTE's energy purchases outside of this regulated mechanism will be highly limited. CRE has therefore not renewed this mechanism for the TURPE 4 application period.

For the 2013-2016 period, the purchase of energy required to compensate losses will represent almost 15% of the expenses to be covered by the present tariffs. In the interest of minimising public transmission grid operating costs, CRE consulted stakeholders about the relevance of implementing an incentive for controlling the volume of losses in the public transmission grid. The mechanism adopted within the framework of the present tariffs provides for a follow-up of the actions undertaken by RTE to contain the rate of losses in the grid it operates, without subjecting these actions to a financial incentive. Discussions with RTE revealed that the system operator's room for manoeuvre to control the rate of losses in the public transmission grid is relatively limited. This observation is shared by stakeholders that gave their opinion on this topic within the framework of CRE's public consultations.

The mechanism adopted is based on RTE's annual report to CRE on the following indicators:

- monthly volume of losses avoided in MWh;
- qualitative elements on the type of actions undertaken during the year to limit the volume of losses;
- volume of losses associated with the main investment projects in MWh;
- rate of losses in the public transmission grid.

E. Tariff structure and rules applicable to users of the high-voltage network

Article L. 341-3 of the French Energy Code states that "*the methodologies used to establish tariffs for the use of public electricity transmission and distribution grids are set by the French Energy Regulation Commission*". It is completed by Article L. 341-2 of the same Code that states that "*the tariffs for using the public transmission network and the public distribution networks shall be calculated 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 operator [...]".* Lastly, Article L. 341-4 specifies that "*the structure and level of the tariffs for the use of the public electricity transmission and distribution grids are set in such a way as to encourage clients to limit their consumption during periods in which client consumption on a whole is at its highest*".

Within the framework of the legislative provisions quoted above, CRE carried out thorough work on the structure of grid infrastructure costs and the cost of losses, which represent the major portion of total expenses to be covered by the tariffs. The methodology used as well as the results of this work were presented to stakeholders within the framework of CRE's public consultations of 6 March 2012 and 6 November 2012, the summaries of which can be consulted on CRE's website.

The new methodology for constructing the tariffs takes into account the time difference of grid costs depending on the hours of the year and allocates to the different users these costs based on their consumption characteristics. Therefore, users with a high level of consumption during periods in which the consumption of all users is highest bear a major portion of the grid costs. They are thus encourage to defer their consumption during the grids' peak times to times during which the grids are the least solicited, which will minimise expenses related to the use of public electricity grids in the long term.

This new tariff structure complies both with the principle of non-discrimination of tariffs specified in Article L. 341-2 of the Energy Code and the goal to control energy demands set forth in Article L. 341-4 of the same code.

On the basis of this new methodology for constructing tariffs, CRE has introduced a time differentiation for tariffs for high-voltage grids (HTB 2 and HTB 1). CRE has maintained a concave tariff for the high-voltage grid 3 (HTB 3).

Before describing in detail the methodology used to construct the present tariffs, CRE wishes to reiterate the general principles on which it based its decision on tariff structure.

1. General principles

To make its tariff decision, CRE has retained the following general principles.

1.1. Tariffs independent of distance

In compliance with the provisions in Article 14, Paragraph 1, of (EC) Regulation No. 714/2009 of 13 July 2009, specifying that network access charges do not depend on the distance separating a producer and a consumer involved in a transaction, CRE has maintained the principle of *"postage stamp"* pricing, which consists in billing withdrawals at the same price regardless of the origin of the electricity consumed, and billing injections regardless of the destination of the electricity produced. The "postage stamp" pricing does not exclude the possibility of a geographical differentiation of tariffs.

1.2. Identical tariffs throughout the territory

The present tariffs are identical throughout the territory.

Against the backdrop of a strong increase in the need for investments in the grids, in particular to respond to the development of new production means and within the framework of European objectives in that area, the matter of the relevance of a locational signal for producers has been raised. A locational signal, which could take the form of a spatially differentiated injection tariff, may enable the improvement of coordination between the different investments in the grid and in production means, and therefore reduce grid costs in the long term.

Initial analyses were conducted on this subject, the results of which were presented to stakeholders within the framework of CRE's public consultation of 6 March 2012. The spatial differentiation of the injection tariff is one tool to improve coordination of production and transmission investments. Other options may be envisaged such as the introduction of nodal prices or the modification of the connection price depending of the area. Each of these options has advantages and disadvantages which require further consideration. Moreover, this issue is the subject of discussions at European level. Given this context, CRE deems it necessary, before envisaging the implementation of such a locational signal for producers, to assess the effects of tools already set up to improve this coordination[7] and to know the guidelines that the European Commission may adopt on this locational signal matter, pursuant to the provisions of Article 18 of EC Regulation No. 714/2009 of 13 July 2009.

Moreover, the heterogeneity of the opinions of stakeholders that gave their opinion on these matters and the guidelines of the energy policy indicated by the Minister of Ecology, Sustainable Development and Energy by letter dated 10 October 2012 consolidated the idea that it was too early to undertake spatial differentiation of the injection tariff.

1.3. Sharing of high-voltage grid costs between withdrawal and injection is based on European texts

Article 4 of Decree No. 2001-365 of 26 April 2001 specifies, on this matter, that the "*tariffs take into account the measures adopted by the European Union to harmonise pricing applicable to international energy exchanges and facilitate international exchanges in electrical energy*".

European guidelines on injection tariffs and the mechanism for compensation among transmission system operators for transit flows, specified by European Regulation No. 838/2010 of 23 September 2010, present the criteria on which the injection tariff must be based. These criteria are met in the present tariffs.

2. Methodology for constructing tariffs

The new tariff construction methodology is based on the following steps:

2.1. Tariffs based on hourly unit costs

The present tariffs, whether or not they propose different time categories, are defined on the basis of hourly unit costs for the use of the grids. Taking into account hourly unit costs in the tariff construction is carried out in two stages described below.

2.2. Distribution of costs over the different hours of the year

A same withdrawal volume does not result in the same grid costs according to the time of day during which this withdrawal is made. An examination of grid costs show that during the hours in which there is a considerable level of transmission in the grids, an incremental

[7] These tools include in particular the "Grid Prospects" commission set up within the committee of clients that use the electricity transmission system (CURTE) in 2011, the calls for tender to develop production in Brittany and to develop production from offshore wind farms and the consultations implemented at regional level to define the regional climate air and energy plans.

COMMISSION
DE RÉGULATION
DE L'ÉNERGIE

withdrawal generates higher incremental costs for losses and infrastructure development than during times when there are fewer loads in the grids.
Grid costs are therefore distributed over the different hours of the year. For each voltage range, unit costs for the use of the grid are calculated for each hours of the year. These hourly unit costs are calculated as the sum of the hourly unit cost of infrastructure and the hourly unit cost of losses. The hourly unit costs of infrastructure are calculated using the average incremental cost resulting from the load increase at each hour of the year. The hourly unit costs of losses are calculated using the electricity spot price profile on the French market, purged of trends.

2.3. *Allocation of hourly costs among users of the different voltage ranges proportionally to energy flows in the grids*

On the basis of the matrix of forecast flows communicated by RTE for the 2013-2016 period, it is observed that energy is injected mainly at very high voltage to be consumed mostly by users connected to downstream voltage ranges. The energy flows successively use portions of the grid at decreasing voltage levels. Therefore, the downstream grid users contribute, by the flow of energy they generate, a large portion of the costs borne by RTE for the management of the grids upstream. This is why the tariff income received from users serves to cover not only the costs of the voltage range to which they are connected but also a portion of the costs of upstream voltage ranges.
The calculation of this contribution of withdrawals from a voltage range to the costs of upstream voltage ranges is based on the matrix of forecast flows and the distribution of accounting costs by voltage range, also sent by RTE to CRE.
Since the allocation of costs of one voltage range to downstream voltage ranges is on an hourly basis, the time differentiation of grid costs is passed on to all users.
Once this allocation of hourly costs is carried out among users of different voltage ranges, it is possible to deduct from it for each voltage range a global envelope of costs to be covered by all users of this voltage range. This global envelope is then distributed among the users of this voltage range depending on their consumption characteristics.

2.4. *Tariffs based on the consumption characteristics of users*

All users of the same voltage range do not consume in the same manner. Users' consumption characteristics are used to distribute the global envelope of costs allocated to the voltage range to which they are connected. The costs that each type of user generates within the same voltage range depend specifically on the rate of use of subscribed power (that can be referred to as duration of use) and the time distribution of withdrawals over the year.
The rate of use of subscribed power serves to determine a variable portion depending on the energy consumed and a fixed portion depending on the power subscribed. While the subscribed power is a decisive variable for grid costs, it is not sufficient on its own to determine the costs generated by a user on the grids. It is also important to know the way in which this subscribed power is used: a customer that uses all of its power subscribed during the grids' on-peak hours generates more grid costs than a customer that uses only a portion of its subscribed power during those times.
The use of hourly grid costs enable the withdrawal profile of the different users to be taken into account in the grid costs allocation process. Thus, for a same annual consumption volume, a user that consumes at times during which grid costs are high will contribute more to grid costs than a user that consumes at times during which grid costs are low.
For each voltage range, the global envelope of costs is therefore distributed among users connected to the same voltage range in question depending on the level of their subscribed

power, the total volume of energy they withdraw over the year, and the distribution of their subscribed power and the volume of energy withdrawn over the different hours of the year. The tariffs with time differentiation are defined by distributing costs among the different time categories. In particular, the "energy" portion of each time category is defined as to be proportional to the average unit cost for the given time category.

2.5. Form of tariff scales

The time categories for tariffs proposed to users connected to high-voltage ranges (HTB 2 and HTB 1) are designed to maximise the homogeneity of hourly unit costs within each time category while maximising the heterogeneity of hourly unit costs between time categories. Further clarity of tariffs, which stakeholders highlighted in their answers to the public consultations of 15 July 2010 and 6 March 2012, requires limiting the number of time categories and distributing them consistently over the year.
Users of HTB 2 and HTB 1 voltage ranges can choose between three tariff options. Each of these tariff options has five time categories. The time categories of tariffs applicable to the HTB 2 and HTB 1 voltage ranges are defined as follows:

On-peak hours ($i = 1$)	Mid-peak winter hours ($i = 2$)	Off-peak winter hours ($i = 3$)	Mid-peak summer hours ($i = 4$)	Off-peak summer hours ($i = 5$)
From 9:00 a.m. to 11:00 a.m. and 6:00 p.m. to 8:00 p.m. on working days in January, February and December	From 7:00 a.m. to 9:00 a.m., 11:00 a.m. to 6:00 p.m. and 8:00 p.m. to 11:00 p.m. on working days in January, February and December From 7:00 a.m. to 11 p.m. on working days in November and March	From 11:00 p.m. to midnight and midnight to 7:00 a.m. on working days in November and March All day on non-working days from November to March	From 7:00 a.m. to 11 p.m. on working days from April to October	From 11:00 p.m. to midnight and midnight to 7:00 a.m. on working days from April to October All day on non-working days from April to October

The concave tariff has been maintained for users connected to the HTB 3 voltage range. As stated in CRE's public consultations of 6 March 2012 and 6 November 2012, a tariff with time differentiation for the HTB 3 voltage range could lead to consumption movements unfavourable to long-term cost minimisation for the large-scale transmission network, which aims to pool production resources at national and European level. This aim, specific to the large-scale network, involves a different architecture and operating mode than those of the distribution networks.
At a given time of the day, economic precedence, geographical location of power plants and the availability of grid serve to determine plans for production and exchanges at borders which enable national and also external demand to be met. These plans give rise to transit distribution across the different elements of the HTB 3 network.
The determination of a geographical equalised tariff structure is based on the hourly profile of aggregated grid costs at the national level. The analysis of this aggregated hourly cost

profile does not reveal any correlation between this profile and the national consumption profile. This absence of correlation is due in particular to the fact that the basic production means are generally far away from the sites towards which the energy is transmitted. Therefore, there are times of the day during which national consumption is at its lowest level and transit flows in the large-scale transmission network are at their highest.
This is why, even if the dimensioning of the HTB 3 grid and therefore its total cost depend on the general consumption level, the hourly profile of costs is not related to the hourly profile of consumption. Therefore, an HTB 3 tariff with time differentiation could increase the costs of the large-scale transmission network in the long term by encouraging users to defer their consumption to off-peak periods at national level, but during which transit flows in the HTB 3 voltage range are already high.
In addition, the impact of the location of production means on the definition of transit plans on the large-scale network, and therefore on the HTB 3 grid costs, raise the question of the relevance of the differentiation of the price paid by producers to use the gird depending on their geographical location. As previously stated, the challenges raised by this matter require further analysis.

3. Tariff structure applicable to users of the high-voltage grid (HTB)

The rules contain 13 sections. The first two define the concepts used and the tariff structure. Sections 3 to 12 describe the tariff components. Section 13 specifies the transitional provisions applicable to the power subscription of HTB grid users.
The rules defined under TURPE 3 are therefore renewed for the most part. However, given the feedback provided by the system operator and the contributions received during CRE's public consultation of 6 November 2012, some provisions of the tariff rules have been modified or completed. Moreover, the introduction of tariffs with time differentiation for the HTB 2 and HTB 1 voltage ranges involves a substantial modification of section 6 of the rules which specifies the provisions for defining annual withdrawal components and monthly components for overruns of power subscribed at high-voltage (HTB) ranges.

3.1. Definitions

The definitions of the terms "lines" and "user" are completed in order to clarify the terms of application of the present tariffs.

3.2. Tariff structure

Section 2 contains a description of the different categories of expenses to be covered by the present tariffs, the tariff structure established so as to reflect these different categories of expenses and the method for applying the different tariffs at each connection point.

3.3. Management

The terms for billing the management component specified under TURPE 3 have been renewed, namely, explicit billing of management fees in the form of a fixed charge applied to all users (producers, consumers and system operators) depending on the voltage range of their connection.
In order to better reflect the system operator's costs, the annual management component is billed by connection point and by access contract.
Contract management costs are made up of costs related to grid user reception, management of user files, billing, debt recovery and outstanding amounts.

3.4. Metering

Pricing of the metering component applicable to users of high-voltage networks depends on the ownership of the meter.
For users who own their metering system, the metering component covers costs:

- for checking that metering equipment is working correctly conducted on the initiative of the system operator;
- for reading or remote reading (including subscription and communication costs);
- for measuring, calculating and recording of metering data;
- for validating, correcting and provisioning validated metering data available.

Metering data is sent to the user or to a third party authorised by the user at a minimum frequency defined according to the subscribed voltage range and withdrawal power to which they have subscribed and/or the connection point's maximum injection power.
For users whose metering system is owned by the system operator or concessionary authorities, the metering component also covers the following costs:

- capital costs of metering devices after deduction of the share of connection contributions regarding metering devices;
- maintenance costs for metering equipment;
- renewal costs of metering equipment;
- where necessary, costs for synchronisation of metering equipment.

However, this metering component does not include the cost to change metering systems at users' request or at the request of a third party authorised by the user, which is subject to specific billing under the tariff rules related to additional services provided under the monopoly of the system operator.

3.5. Injection

Since France is a net exporter of electrical energy, RTE's net contribution to the European inter-TSO compensation mechanism for transits is positive. French grid users must not bear the cost of this contribution, for which exporters are responsible.
The injection tariff is set at €19 c/MWh over the entire tariff period for producers connected to the HTB 3 and HTB 2 voltage ranges. This amount takes into account RTE's contribution to the European inter-TSO compensation mechanism.

3.6. Withdrawal

The rules applicable for the calculation of components used to bill subscribed power withdrawals and power overruns are adapted due to the introduction of tariffs with time differentiation for users connected to the HTB 2 and HTB 1 voltage ranges.
The monthly subscribed power overrun components (CMDPS) are calculated so that users exceeding their subscribed power by 10% for 100 hours of the same time category will pay the same bill as though they had subscribed 10% more power. The renewal of this calculation method preserves users' incentive to subscribe optimum power.

3.7. Complementary and back-up power

For complementary and back-up power lines, only the assigned parts are billed. This billing method takes into account the fact that, given the grid dimensioning rules of "N-1", it is not possible to distinguish surcharges related to supply of complementary or back-up capacity.
A subscribed power overrun coefficient for back-up power, when this is connected to a voltage range that is different to that of the main supply, has been introduced. This provision guarantees that the incentive given to users to subscribe optimal power also applies when they subscribe back-up power.

3.8. Tariff aggregation of connection points

The consolidation mechanism in application since 1 January 2006 has been renewed for the TURPE 4 tariff period.

3.9. Tariff provisions applicable to public distribution system operators

Public distribution system operators have specific characteristics that are defined by law and regulations. To include these specific characteristics in the tariffs applicable to the different voltage ranges, the following special provisions have been maintained:

- transformer use is billed depending on the average direct loads of the transformer station;
- compensation for operating lines at the same voltage as the public grid upstream is determined based on the difference between tariffs in the delivery voltage range and in the voltage range directly below, decreased by the transformer use component and weighted by the parts of these lines operated by the various system operators;
- peak shaving of monthly bills for distributor power overruns is authorised in cases of extreme cold, under the same conditions as for TURPE 2.

The definition of the terms *l1* and *l2*, used to calculate compensation for operating lines at the same voltage as the public grid upstream, are clarified.

3.10. Sporadic use

In order to take into account certain situations when network capacities can transmit power drawn for short periods without any adverse effects for other users, the system for billing scheduled temporary power overruns (DPP) as defined in TURPE 3 has been renewed. These overruns, which must have prior approval by the system operator, are billed at the average price of energy withdrawn by a user with a rate of use of 25%.
DPP requests are conditioned by the completion of work on the electricity facilities of the requesting party.
The DPP mechanism is transitional so that public distribution system operators are not penalised.

3.11. Reactive energy

The specific pricing system applied to reactive energy transit at public distribution grid points of connection to the public transmission grid has been renewed in order to stabilise the volume of HTA condensers and therefore maintain reactive power capacity production in the public distribution grids.

A scale sets the penalties in the event of exceeding a "*phi tangent"* range contractually agreed by the parties with regard to the rules recorded in the reference technical documentation of the public transmission system operator.
Failing such agreement between the parties, the present tariff rules specify the method for determining the upper limit of the "phi tangent" range. This method is based on the use of historical values and provides for the introduction of a limit value.
This limit value is justified in particular by the rapid development of decentralised production and the trend towards natural increase of "phi tangents" in the public distribution grids, and avoids excessive differences in treatment between connection points.

3.12. Indexation of the pricing scale

All of the pricing scale coefficients, except the subscribed power weighting coefficient, coefficient *c* of the withdrawal component applicable to the high-voltage (HTB 3) range and the injection component, are indexed during annual tariff changes.

3.13. Transitional provisions

A learning period for power subscription is defined. The objective of this learning period is to enable, during the initial months of TURPE 4 application, the billing of a catch-up charge to limit the consequences of the loss of income caused by the introduction of tariffs with time differentiation to replace concave tariffs.
This transitional provision will enable users that have modified their withdrawal behaviour in response to the hourly/seasonal signal to receive all the tariff benefits generated.
Two adjustment dates are set: 31 December 2013 and 31 March 2014 (last day of the winter season) in order to facilitate the accounting management of the mechanism and to allow users benefitting from a possible "Peak shaving in extreme cold weather" clause to record the corresponding tariff reduction under the 2013 fiscal year.

F. Annex

1. RTE's R&D programme

RTE intends to carry out, over the next tariff period, R&D projects structured on the basis of four programmes.
The "Environment" programme aims at meeting societal expectations is based on the following streams: research on the interaction between electromagnetic fields and health: research on biodiversity in particular in the underwater environment; study of the tools and methods for reducing the ecological footprint of RTE's activities and academic work in the sociological field to improve the adhesion of stakeholders to grid development or project upgrading. The projects of this programme include:

- a "sustainable development substation" demonstrator in the Somme department aimed at reducing the ecological footprint during the structure's service life, which will be completed in 2014;
- a research project to gain a better knowledge of the threshold above which physiological effects begin to manifest themselves due to exposure to a magnetic field. The outcomes of this project, expected in 2015, will serve to better control worker exposure, in particular during live-line operations;
- a project aimed at proposing methods and tools for dialogue with stakeholders relating to grid projects, the results of which are expected in 2015.

The “Grid assets management and maintenance” programme aims to develop tools and innovative methods to optimise technical grid upgrading and replacement policies, and to optimise maintenance so as to allow maximum availability of the grid. The projects of this programme include:

- *Smartlab*: development of tools for simulation of component ageing phenomena and for optimisation of grid assets management scenarios;
- Drones and robots: this project will provide maintenance operators with tools to facilitate diagnosis by ensuring their safety. The initial results for the diagnosis of joint deterioration, the state of conductors with cut wires will be validated at the end of 2013. The following steps will serve to broaden the range of use of robots and drones.

The “Electric power system” programme is intended to support the development of methods and tools to optimise an electric power system incorporating a larger portion of intermittent renewable energy. The projects of this programme include:

- *iTesla*: an innovative approach to the analysis of the safe operation of grids by a probabilistic approach. The risk models and analysis tools are expected at the end of 2014, and the final delivery of the toolkit for end 2015;
- Models for forecasting intermittent production: the results for photovoltaic energy are expected in 2013, and in 2015 for offshore wind power. Studies are also being conducted on common methods in order to analyse the correlations between forecasting models for photovoltaic energy, wind power and hydro-power, to extract refined forecasts. The results of these studies are also expected in 2015. These tools will be essential for controlling the balance between supply and demand;
- *SmaRTE*: this simulation platform will serve to develop tools and methods for anticipating phenomena related to the insertion of complex components into the power grids such as static VAR compensators, long cable lines and alternating-current/direct-current conversion stations. The development of new models in 2013 will serve to refine studies on the integration of the direct-current line between France and Spain into the grid.

The “Power grid of the future” programme aims to anticipate and accelerate the development of innovative technology prefiguring tomorrow’s power grid. The projects of this programme include:

- *Twenties*: to knock down certain technological barriers to the development of a meshed direct current grid. In 2013, a laboratory prototype of a direct current circuit breaker will be tested;
- Smart substations: Smart grid project aimed, through the extensive integration of process digitisation, at facilitating the integration of renewable energy in the grid. The commissioning of this demonstrator is scheduled for 2016.

In addition, RTE participates actively in learned societies and in international standardisation works, in particular within CIGRE, IEEE, IEC and CENELEC.

The Smart grid theme is bolstered by the “Electric power system” and “Power grid of the future” programmes. Annual follow-up will include a summary of progress regarding the Smart grid theme resulting from the concatenation of different projects.

On an indicative basis, RTE envisages that R&D expenses, by theme, will break down as follows (in current €M)

Theme	2013	2014	2015	2016	Total

Environment	1.2	1.4	1.4	1.5	5.5
Asset management and maintenance	9.2	9.4	10.2	10	38.8
Electric power system	6.9	7.9	9.1	9.2	33.1
Power grid of the future	5.8	6.3	7.3	9.3	28.7
Standardisation and learned societies	0.6	0.6	0.6	0.7	2.5
Total	**23.7**	**25.6**	**28.6**	**30.7**	**108.6**

2. Summary of the tariff scale

Management component

a_1 (€/year)	Grid access contract signed by user	Grid access contract signed by supplier
HTB	7,884,80	7,884,80

Metering component

Metering systems owned by the public electricity system operator or concessionary authorities

Voltage range	Minimum transmission frequency	Power control	Values measured	Annual metering component €/year
HTB	Weekly	Overrun	Measurement curve	2,726,22

Metering systems owned by users

Voltage range	Minimum transmission frequency	Power control	Values measured	Annual metering component €/year
HTB	Weekly	Overrun	Measurement curve	489,43

Injection component

Voltage range	c€/MWh
HTB 3	19
HTB 2	19
HTB 1	0

Withdrawal components

Tariff for the HTB 3 voltage range

Voltage range	a_2 (€/kW/year)	b (€/kW/year)	c
HTB 3	4.75	19.25	0.856

Tariff for the HTB 2 voltage range

Medium-term use

a_2 (€/kW/year)	8.60

	On-peak hours (*i* = 1)	Mid-peak winter hours (i = 2)	Off-peak winter hours (*i* = 3)	Mid-peak summer hours (*i* = 4)	Off-peak summer hours (*i* = 5)
Energy weighting coefficient (c€/kWh)	0.61	0.54	0.40	0.36	0.27
Power weighting coefficient	100%	94%	68%	44%	19%

Long-term use

a_2 (€/kW/year)	11.26

	On-peak hours (*i* = 1)	Mid-peak winter hours (*i* = 2)	Off-peak winter hours (*i* = 3)	Mid-peak summer hours (*i* = 4)	Off-peak summer hours (*i* = 5)
Energy weighting coefficient (c€/kWh)	0.50	0.44	0.32	0.29	0.20
Power weighting coefficient	100%	95%	69%	45%	19%

Very long-term use

a_2 (€/kW/year)	14.42

	On-peak hours (*i* = 1)	Mid-peak winter hours (*i* = 2)	Off-peak winter hours (*i* = 3)	Mid-peak summer hours (*i* = 4)	Off-peak summer hours (*i* = 5)
Energy weighting coefficient (c€/kWh)	0.43	0.37	0.27	0.24	0.17
Power weighting coefficient	100%	95%	69%	46%	20%

Tariff for the HTB 1 voltage range

Medium-term use

a_2 (€/kW/year)	14.33

	On-peak hours ($i = 1$)	Mid-peak winter hours ($i = 2$)	Off-peak winter hours ($i = 3$)	Mid-peak summer hours ($i = 4$)	Off-peak summer hours ($i = 5$)
Energy weighting coefficient (c€/kWh)	1.25	1.08	0.78	0.66	0.47
Power weighting coefficient	100%	94%	67%	41%	18%

Long-term use

a_2 (€/kW/year)	15.72

	On-peak hours ($i = 1$)	Mid-peak winter hours ($i = 2$)	Off-peak winter hours ($i = 3$)	Mid-peak summer hours ($i = 4$)	Off-peak summer hours ($i = 5$)
Energy weighting coefficient (c€/kWh)	1.22	1.04	0.74	0.62	0.43
Power weighting coefficient	100%	94%	67%	42%	18%

Very long-term use

a_2 (€/kW/year)	19.20

	On-peak hours ($i = 1$)	Mid-peak winter hours ($i = 2$)	Off-peak winter hours ($i = 3$)	Mid-peak summer hours ($i = 4$)	Off-peak summer hours ($i = 5$)
Energy weighting coefficient (c€/kWh)	1.16	0.97	0.68	0.57	0.39
Power weighting coefficient	100%	94%	67%	43%	18%

1. Definitions

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

1.1. Absorption of reactive power

1.2. Transit of reactive electrical energy via the connection point used to serve the user of the public electricity grid. Power supply

If users are connected to the public grid by several power supplies, the main, complementary and back-up power sources should be identified in a contract with the operator of the public system to which they are connected.

2.1.1. Main power supply

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

2.1.2. Back-up power supply

A user's power supply is a back-up power supply if it is a live circuit that is only used for the transfer of power between the public network and the installations of one or more users in the event of unavailability of all or part of their main and complementary power supplies.
The assigned part of a back-up power supply is the part of public grids which is only crossed by flows with the destination of one or more connection points to one or more back-up power supplies of this user or another user.
Flows taken into account to establish the assigned part of back-up power supplies are those which are established under normal operating conditions in the event of unavailability of all or part of other power supplies for the user's electrical equipmentsagreed by contract with the public system operator to which they are connected given the typology of the public grid and whatever operations the operator may be carrying out on them.

2.1.3. Complementary power supply

A user's power sources which are neither main power supplies nor back-up power supplies are considered as this user's complementary power supplies.
The assigned part of a complementary power supply is the part of the public grid which is only crossed by flows originating from or with the destination of one or more connection points belonging to this user.
Flows incorporated to establish the assigned part of complementary power supplies are those which are established under normal operating conditions of the electrical equipments of the user agreed to by contract with the operator of the public grid to which they are connected, given the public grid topology and whatever operations their operator may be carrying out.

1.3. Cell

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

1.4. Time category

For any tariff for the use of public electricity grids, the time category is the set of hours in the year to which the same tariff coefficient is applied.

1.5. Grid access contract

A grid access contract is the contract referred to in Articles L. 111-91 to L. 111-95 of the French Energy Code, which defines the technical, legal, and financial terms for user access to a public transmission or distribution grid to withdraw and/or inject electrical power. It is signed with the public system operator either by the user or by the supplier on the user's behalf.

1.6. Measurement curve

A measurement curve is a set of average values stamped with the hour and date for a variable measured over consecutive integration periods of the same duration. The load curve is a curve measuring the active energy withdrawn.
Integration periods are consecutive intervals of time of the same duration during which average values of an electrical variable varying over time are calculated. When the current rules state that the variables are calculated per integration period, the value of these variables is reduced for each integration period to their average value during this period.

1.7. Metering system

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

1.8. Voltage range

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

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

The tariffs for the use of public electricity grids applicable to users connected to public high-voltage grids (HTA 2) are those of the high-voltage (HTB 1) range.

1.9. Supply of reactive power

Transit of reactive electrical energy through the connection point for public electricity grid supply by the user.

1.10. Index

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

1.11. Active power injection

Transit of active electrical energy through the connection point for public electricity grid supply by the user.

1.12. Busbar

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

1.13. Electrical line

An electrical line is composed of a circuit, a set of conductors and, if needs be, an overhead earth wire.
However, when a transformer and a busbar are situated within the same substation or within two adjoining substations, the circuit connecting the transformer to the busbar is not an electrical line for the purposes of the present tariff rules, but is an integral part of the transformers.

1.14. Transformers

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

1.15. Connection points

A user's connection point(s) on the public grid coincide(s) with the ownership limit between the user's electrical equipment and the public grid electrical equipment, normally corresponding to the boundary of the electrical equipment, marked off by a disconnecting device able to interrupt non-zero current flows between the two extremities of the device. For the application of the current rules, for a user with several connection points on the public grid, it is considered that all or part of these points are mixed, if under normal operating conditions of the user's electrical equipment contractually agreed with the public system operator(s), they are connected by this user's electrical equipment to the connection voltage.

1.16. Active power (P)

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

1.17. Apparent power (S)

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

1.18. Reactive power (Q) and reactive energy

Reactive power Q is equal to active power multiplied by the *tg φ* ratio.
Reactive energy refers to all reactive power *Q* over a set period of time. Reactive energy is stored in the form of an electromagnetic field within electricity grids, but is not consumed by users.

1.19. Phi tangent (tg φ) ratio

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

1.20. Withdrawal of active power

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

1.21. User

A public transmission or distribution system user is any private individual or any legal entity, especially public system operators, directly supplying this public grid or directly served by this grid. Interconnection circuits are not considered as users under the present rules.

2. Structure of the tariffs for the use of public grids

The tariffs below are expressed without any deduction or taxes applicable to the use of public electricity grids including the pricing contribution mentioned in article 18-I of the amended law No. 2004-803 of 9 August 2004 on the public electricity and gas service and companies in the electricity and gas sectors.
Pursuant to Article L. 341-2 of the French Energy Code which states that "*the tariffs for using the public transmission network and the public distribution networks shall be calculated 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 operator*" and to Article 2 of the amended Decree No. 2001-365 of 26 April 2001, the tariffs cover in particular:

- costs related to the constitution of operating reserves which consist of costs related to the acquisition by public system operators of system services for voltage control and costs for constituting primary and secondary reserves for frequency control;
- costs related to operating the balance responsible entity system for electricity consumption and/or production sites with a connection point on the public transmission and distribution grids;
- costs for metering, inspection, reading, validation and transmission of metering data;
- the share of costs of additional services provided under the monopoly of public system operators not covered by the tariffs for these services;
- the share of public electricity grid extension costs not covered by the contributions paid to public system operators when they are the contracting authority of the connection work.

An exception is also made for certain specifically identified services provided at a user's request or resulting from their own doing, which are billed separately, in particular in line with the terms laid out in the decision(s) approving the tariff proposal(s) regarding additional services provided under the monopoly of public electricity system operators in application, for the share of their costs that are not covered by the tariffs for the use of public electricity grids defined in sections 3 to 11 hereafter. The same applies to the use of interconnections with transmission grids in neighbouring countries which is billed according to the results of market mechanisms set up in application of EC Regulation No. 714/2009 of 13 July 2009 on conditions for access to the network for cross-border exchanges in electricity.

The grid access contract stipulates the user's connection point(s) on the public grid concerned and the tariff applied. For each connection point, it also specifies the connection voltage range, subscribed withdrawal power and the metering system deployed. Subscribed withdrawal power is defined at the beginning of a period of twelve consecutive months for the whole period, subject to the transitional provisions set out in section 13. The network access contract describes conditions under which the subscribed withdrawal power capacity can be changed during this period.

At each connection point, the annual price paid for the use of a public electricity grid is the sum of the following items:

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

- the annual reactive energy component (CER).

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

Only the energy corresponding to physical flows measured at the connection point concerned is used to calculate annual injection and withdrawal components, measured per integration period by the contractually agreed metering system.

3. Annual administrative management component (CG)

The annual administrative management component in the grid access contract covers the costs of managing user files, physical and telephonic reception of customers, billing and debt recovery.

The annual management component in an access contract concluded by an exclusive supplier is also applicable to:

- consumers who have not exercised the right granted in Article L. 331-1 of the French Energy Code;
- users who benefit from a purchase price prior to the amended law No. 2000-108 of 10 February 2000 on the modernisation and development of the public electricity service.

The annual management component *a1* is determined for each connection point of one or more main power supplies and for each access contract, in line with table 1 below:

Table 1

a_1 (€/year)	Grid access contract signed by user	Grid access contract signed by supplier
HTB	7,884,80	7,884,80

4. Annual metering component (CC)

The annual metering component covers the costs of metering, inspection, reading, transmission of metering data (submitted to the user or an authorised third party at minimum intervals defined in tables 2.1 and 2.2 below), and, if needs be, rental and maintenance costs.

It is determined depending on the technical characteristics of metering systems and services requested by the users, in line with the tariffs below. Variables measured by the user's measuring and testing equipment must provide for calculation of annual components included in the tariff for the use of public grids.

The annual metering component is determined for each metering system and for each access contract according to tables 2.1 and 2.2 below, depending on the ownership of the metering system.

4.1. Metering systems owned by the public electricity system operator or concessionary authorities

The annual metering component billed to users whose metering system belongs to the public system operator or concessionary authorities is defined in table 2.1 below, according to the voltage range, subscribed withdrawal power and/or maximum injection power, power control and variables measured (index or measurement curve).

Table 2.1

Voltage range	Power (*P*)	Minimum transmission frequency	Power control	Values measured	Annual metering component €/year
HTB	-	Weekly	Overrun	Measurement curve	2,726,22

4.2. Metering systems owned by users

The annual metering component billed to users that own their metering system is defined in table 2.2 below, according to the voltage range, subscribed withdrawal power and/or maximum injection power, power control and variables measured (index or measurement curve).

Table 2.2

Voltage range	Power (P)	Minimum transmission frequency	Power control	Values measured	Annual metering component €/year
HTB	-	Weekly	Overrun	Measurement curve	489,43

5. Annual injection component (CI)

The annual injection component is determined at each connection point, depending on the active energy injected on the public grid, according to table 3 below:

Table 3

Voltage range	c€/MWh
HTB 3	19
HTB 2	19
HTB 1	0

6. Annual withdrawal components (CS) and monthly components for subscribed power overruns (CMDPS) in high-voltage ranges (HTB)

6.1. Annual withdrawal component (CS)

6.1.1. Tariff for the HTB 3 voltage range

Users choose a subscribed power, $P_{Subscribed}$, in multiples of 1 kW for each of their connection points in the HTB 3 voltage range. At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2.P_{Subsribed} + b.\tau^c.P_{Subscribed} + \sum_{12\ months} CMDPS$$

The rate of use τ is calculated based on active energy $E_{withdrawn}$ in kWh over the period of 12 consecutive months under consideration, the subscribed power $P_{Subscribed}$ in kW and duration D in hours of the year considered according to the following formula:

$$\tau = \frac{E_{withdrawn}}{D.P_{Subscribed}}$$

Coefficients a_2, b and c used are those in table 4 below:

Table 4

Voltage range	a_2 (€/kW/year)	b (€/kW/year)	c
HTB 3	4.75	19.25	0.856

6.1.2. Tariff for the HTB 2 voltage range

For each of their connection points in the HTB 2 voltage range, users choose, for each of the n time categories it is made up of, subscribed power P_i in multiples of 1 kW, where i designates the time category. Whatever the value of i, subscribed power must be such that $P_i+1 \geq P_i$.
At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2.P_{Subscribed\ \ weighted} + \sum_{i=1}^{n} d_i.E_i + \sum_{12\ months} CMDPS$$

E_i designates active energy withdrawn during the i^{th} time category, expressed in kWh.
$P_{subscribed\ weighted}$ designates weighted subscribed power calculated according to the following formula:

$$P_{Subscribed\ \ weighted} = k_1.P_1 + \sum_{i=2}^{n} k_i.(P_i - P_{i-1})$$

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

- winter is November to March;
- summer is from April to October;
- on-peak hours are set, from December to February inclusive, between 9:00 a.m. and 11:00 a.m. and between 6:00 p.m. and 8:00 p.m.;

- mid-peak hours are set between 7:00 a.m. and 11:00 p.m., outside of the on-peak hours previously defined;
- the other hours of the day are defined as off-peak hours;
- Sundays, Saturdays and public holidays are fully considered as off-peak hours.

In order to determine their annual withdrawal component in the HTB 2 voltage range, users choose one of the three tariff options below:

- medium-term use;
- long-term use;
- very long-term use.

Users keep their tariff option for a minimum period of twelve months starting from the date of entry into force of the tariff option, then starting from the date of each subsequent tariff modification, except for the transitional provision described in section 13. At the end of this twelve-month period, the user may change tariff option at any time.

The a_2, d_i and k_i coefficients used for the "medium-term" tariff option applicable to the HTB 2 voltage range are those in tables 5.1 and 5.2 below:

Table 5.1

a_2 (€/kW/year)	8.60

Table 5.2

	On-peak hours (i = 1)	**Mid-peak winter hours (i = 2)**	**Off-peak winter hours (i = 3)**	**Mid-peak summer hours (i = 4)**	**Off-peak summer hours (i = 5)**
Energy weighting coefficient (c€/kWh)	0.61	0.54	0.40	0.36	0.27
Power weighting coefficient	100%	94%	68%	44%	19%

The a_2, d_i and k_i coefficients used for the "long-term" tariff option applicable to the HTB 2 voltage range are those in tables 6.1 and 6.2 below:

Table 6.1

a_2 (€/kW/year)	11.26

Table 6.2

	On-peak hours (i = 1)	**Mid-peak winter hours (i = 2)**	**Off-peak winter hours (i = 3)**	**Mid-peak summer hours (i = 4)**	**Off-peak summer hours (i = 5)**

Energy weighting coefficient (c€/kWh)	0.50	0.44	0.32	0.29	0.20
Power weighting coefficient	100%	95%	69%	45%	19%

The a_2, d_i and k_i coefficients used for the "very long-term" tariff option applicable to the HTB 2 voltage range are those in tables 7.1 and 7.2 below:

Table 7.1

a_2 (€/kW/year)	14.42

Table 7.2

	On-peak hours ($i = 1$)	**Mid-peak winter hours ($i = 2$)**	**Off-peak winter hours ($i = 3$)**	**Mid-peak summer hours ($i = 4$)**	**Off-peak summer hours ($i = 5$)**
Energy weighting coefficient (c€/kWh)	0.43	0.37	0.27	0.24	0.17
Power weighting coefficient	100%	95%	69%	46%	20%

6.1.3. Tariff for the HTB 1 voltage range

For each of their connection points in the HTB 1 voltage range, users choose, for each of the n time categories it is made up of, subscribed power P_i in multiples of 1 kW, where i designates the time category. Whatever the value of i, subscribed power must be such that $P_{i+1} \geq P_i$.
At each connection point, the annual withdrawal component is determined according to the following formula:

$$CS = a_2 . P_{Subscribed\ weighted} + \sum_{i=1}^{n} d_i . E_i + \sum_{12\ mois} CMDPS$$

E_i designates active energy withdrawn during the i[th] time category, expressed in kWh.
$P_{subscribed\ weighted}$ designates weighted subscribed power calculated according to the following formula:

$$P_{Subsribed\ weighted} = k_1 . P_1 + \sum_{i=2}^{n} k_i . (P_i - P_{i-1})$$

The time categories of the HTB 1 tariff are defined as follows:

- winter is November to March;
- summer is from April to October;
- on-peak hours are set, from December to February inclusive, between 9:00 a.m. and 11:00 a.m. and between 6:00 p.m. and 8:00 p.m.;

- mid-peak hours are set between 7:00 a.m. and 11:00 p.m., outside of the on-peak hours previously defined;
- the other hours of the day are defined as off-peak hours;
- Sundays, Saturdays and public holidays are fully considered as off-peak hours.

In order to determine their annual withdrawal component in the HTB 1 voltage range, users choose one of the three tariff options below:

- medium-term use;
- long-term use;
- very long-term use.

Users keep their tariff option for a minimum period of twelve months starting from the date of entry into force of the tariff option, then starting from the date of each subsequent tariff modification, except for the transitional provision described in section 13. At the end of this twelve-month period, the user may change tariff option at any time.

The a_2, d_i and k_i coefficients used for the "medium-term" tariff option applicable to the HTB 1 voltage range are those in tables 8.1 and 8.2 below:

Table 8.1

a_2 (€/kW/year)	14.33

Table 8.2

	On-peak hours (i = 1)	**Mid-peak winter hours (i = 2)**	**Off-peak winter hours (i = 3)**	**Mid-peak summer hours (i = 4)**	**Off-peak summer hours (i = 5)**
Energy weighting coefficient (c€/kWh)	1.25	1.08	0.78	0.66	0.47
Power weighting coefficient	100%	94%	67%	41%	18%

The a_2, d_i and k_i coefficients used for the "long-term" tariff option applicable to the HTB 1 voltage range are those in tables 9.1 and 9.2 below:

Table 9.1

a_2 (€/kW/year)	15.72

Table 9.2

	On-peak hours (i = 1)	**Mid-peak winter hours (i = 2)**	**Off-peak winter hours (i = 3)**	**Mid-peak summer hours (i = 4)**	**Off-peak summer hours (i = 5)**

Energy weighting coefficient (c€/kWh)	1.22	1.04	0.74	0.62	0.43
Power weighting coefficient	100%	94%	67%	42%	18%

The a_2, d_i and k_i coefficients used for the "very long-term" tariff option applicable to the HTB 1 voltage range are those in tables 10.1 and 10.2 below:

Table 10.1

a_2 (€/kW/year)	19.20

Table 10.2

	On-peak hours (i = 1)	**Mid-peak winter hours (i = 2)**	**Off-peak winter hours (i = 3)**	**Mid-peak summer hours (i = 4)**	**Off-peak summer hours (i = 5)**
Energy weighting coefficient (c€/kWh)	1.16	0.97	0.68	0.57	0.39
Power weighting coefficient	100%	94%	67%	43%	18%

6.2. Monthly components for subscribed power overruns (CMDPS)

The components for subscribed power overruns are set each month according to the terms below:

$$\mathrm{CMDPS} = \alpha . \sqrt{\sum \left(\Delta P^2\right)}$$

Power overruns compared to subscribed power ΔP are calculated per integration period of 10 minutes. The factor applicable for users connected to the HTB 3 voltage range is defined in table 11 below:

Voltage range	α (c€/kW)
HTB 3	19.46

Table 11

The components for subscribed power overruns for HTB 2 and HTB 1 voltage ranges are set each month according to the terms below:

$$CMDPS = \sum_{i \text{ categories of the month}} \alpha . k_i . \sqrt{\sum \left(\Delta P^2\right)}$$

Power overruns compared to subscribed power *ΔP* are calculated per integration period of 10 minutes. The factor applicable to users connected to HTB 2 and HTB 1 voltage ranges depends on the tariff chosen by the user. The factors applicable for users connected to the HTB 2 and HTB 1 voltage ranges are defined in table 12 below:

Table 12

<table>
<tr><th rowspan="2">α (c€/kW)</th><th colspan="2">Voltage range</th></tr>
<tr><th>HTB 2</th><th>HTB 1</th></tr>
<tr><td>Tariff for medium-term use</td><td>35.84</td><td>60.42</td></tr>
<tr><td>Tariff for long-term use</td><td>47.10</td><td>65.54</td></tr>
<tr><td>Tariff for very long-term use</td><td>60.42</td><td>79.87</td></tr>
</table>

7. Annual component for complementary and back-up power supplies (CACS)

Complementary and back-up power supplies established upon the request of users are billed according to the methods described below. The annual component for complementary and back-up power supplies (CACS) is equal to the sum of these components.

7.1. Complementary power supply

The parts dedicated to a user's complementary power supplies are subject to a charge for the electrical equipment of which they are composed. This charge is based on the length of these assigned parts according to the following scale:

Table 13

Voltage range	Cells (€/cell/year)	Lines (€/km/year)
HTB 3	94,206.98	8,927.23
HTB 2	56,814.59	Overhead lines: 5,691.39 Underground lines: 28,455.94
HTB 1	29,510.66	Overhead lines: 3,377.15 Underground lines: 6,754.30

7.2. Back-up power supply

The parts dedicated to a user's back-up power supplies are subject to a charge for the electrical equipment of which they are composed. This charge is based on the length of these assigned parts according to the tariff scale in table 13 above. Power subscribed for back-up power supplies is less than or equal to the power subscribed for main power supplies.

If a back-up power supply is shared among several users, the bill for the parts assigned to back-up power supplies and crossed by flows to several users' connection points is shared among these users at the pro rata of the power which they have subscribed to this back-up power supply.

If the back-up power supply is in the same voltage range as the main power supply and, at the request of the user, it is connected to a public grid transformer different from that used for their main power supply, billing of the parts assigned to back-up power supplies is equal to the sum of the component resulting from application of the tariff scale in table 13 above and the component determined in line with the tariff scale in table 14 below, corresponding to pricing of transformation power reservation:

Table 14

Power supply voltage range	€/kW/year or €/kVA/year
HTB 2	1.37
HTB 1	2.62

If the back-up power supply is in a voltage range different to that of the main power supply, annual billing of back-up power supplies is equal to the sum of the component resulting from the application of the tariff scale in table 13 above and the component determined according to the tariff scale in table 15 below, corresponding to pricing of the public electricity grid providing back-up in a lower voltage range.

If the back-up power supply, which is in a voltage range different to that of the main power supply, is equipped with a meter measuring active power overruns compared to back-up supply power subscribed per integration period of 10 minutes, the monthly subscribed power overrun component for back-up supply is set each month according to the method below:

$$\mathrm{CMDPS} = \alpha . \sqrt{\sum \left(\Delta P^2\right)}$$

Table 15

Main supply voltage range	Backup supply voltage range	Fixed rate (€/kW/year)	Power share (c€/kWh)	*α* (c€/kW)
HTB 3	HTB 2	6.54	0.67	27.65
	HTB 1	4.80	1.15	20.48
HTB 2	HTB 1	1.40	1.15	6.14

8. Component for tariff aggregation of connection points (CR)

A user connected to a public network by several connection points on the same public network in the same HTB voltage range and equipped with meters with measurement curves for each of these points can, if they so wish, benefit from tariff aggregation of all or part of these points for the application of the tariffs described in sections 5 and 6, through payment of an aggregation component. In this case, the annual injection component (CI), annual withdrawal component (CS), monthly components for subscribed power overruns (CMDPS), annual component for sporadic scheduled overruns (CDPP) and annual reactive energy component (CER) are defined based on the sum of the physical flows measured at the connection points concerned. The possibility of tariff aggregation for connection points on

the same public grid is limited to the scope of the same distribution franchise for public distribution system operators and to the same site for other users.
The aggregation of connection point reactive energy flows is only possible in cases where these connection points meet the conditions stated in the reference technical documentation of public the electricity system operator.
The aggregation component (CR) is determined according to the length of the existing public electricity grid for this physical aggregation, independently of operating conditions, and on the transit capacity available on the grid for this aggregation. The amount of this component is calculated according to the following formula, depending on $P_{Subscribed\ aggregated}$, subscribed power for all tariff consolidated points and l, the shortest total length of the electrical equipment on the public grid considered for physical aggregation.

$$CR = l.k.P_{Subscribed\ aggregated}$$

Coefficient k is defined in table 16 below:

Table 16

Voltage range	***k*** **(c€/kW/km/year)**
HTB 3	5.12
HTB 2	Overhead lines: 13.31 Underground lines: 51.20
HTB 1	Overhead lines: 67.58 Underground lines: 118.78

9. Specific provisions for annual withdrawal components (CS) of public distribution system operators

9.1. Annual component for transformer use (CT)

A public distribution system operator that operates one or more overhead or underground lines, downstream of their connection point, in the same voltage range as that downstream of the transformer to which they are directly connected, without an intermediate line upstream of the connection point, can benefit upon request from the annual withdrawal component (CS) applicable to the voltage range just above that applicable to the connection point.

The operator must in this case pay an annual component for transformer use, reflecting the costs of transformers and cells. This component is calculated according to the following formula, depending on subscribed power $P_{Subscribed}$.

$$CT = k.P_{Subscribed}$$

The coefficient k used is that defined in table 17 below:

Table 17

Voltage range of the connection point	**Voltage range of the pricing applied**	**k (€/kW/year)**
HTB 2	HTB 3	1.60
HTB 1 or HTA 2	HTB 2	3.44

HTA 1	HTB 1	6.09

This arrangement can be combined with that of tariff aggregation according to the methods in section 8. In this case, the tariff scale in the voltage range above each connection point is applied first followed by the tariff aggregation mentioned above.

9.2. Compensation for operating lines at the same voltage as the upstream public grid

A public distribution system operator that operates lines downstream of their connection point, in the same voltage range as the lines upstream of this connection point, benefits from this compensation if the pricing applicable to the connection point considered is that of the voltage range of this point.

In this case, the annual withdrawal component (CS) for this connection point is calculated according to the following formula, with:

- l_1, the total length of the line(s) operated in voltage range N by the public distribution system operator;
- l_2, the total length of the line(s) operated in voltage range N by the public distribution system operator to which they are connected and which is absolutely necessary for linking their connection point to this operator's voltage transformer(s) required to guarantee the subscribed power in normal operating conditions defined in the reference technical documentation of the public system operator upstream;
- $CT_{N/N+1}$ is the annual component for transformer use between the voltage ranges of $N+1$ and N defined in section 9.1.

$$CS = \frac{l_2}{l_1 + l_2} CS_N + \frac{l_1}{l_1 + l_2}\left(CS_{N+1} + CT_{N/N+1}\right)$$

9.3. Peak shaving in extreme cold weather

Public distribution system operators can benefit from peak shaving of their power overruns from the public system operator upstream to which they are connected in the event of severe cold spells. This provision is applied in compliance with transparent and non-discriminatory methods.

10. Annual component for sporadic scheduled overruns (CDPP)

For sporadic overruns scheduled for work during the period from 1 May to 31 October and notified to the public system operator in advance, a user, not exclusively supplied by or using one or more back-up power supplies, whose connection point is equipped with a meter with measurement curve and connected to the HTB voltage ranges, can request the application of a specific tariff scale for the calculation of their component for subscribed power overruns related to this connection point.

In this case, during the period when this price scale is applied, subscribed power overruns are subject to the following billing method which replaces the billing for subscribed power overruns defined in section 6.2. Power overruns compared to subscribed power ΔP are calculated per integration period of 10 minutes.

For the HTB 3 voltage range, the formula is as follows:

$$CDPP = \alpha . \sum \Delta P$$

For the HTB 2 and HTB 1 voltage ranges, the formula is as follows with k_i as the subscribed power coefficient of the time category and corresponding tariff option:

$$CDPP = \alpha . k_i \sum \Delta P$$

The factor α applicable is defined in table 18 below:

Table 18

Voltage range	*α (c€/kW)*
HTB 3	0.079
HTB 2	0.156
HTB 1	0.247

In support of their request for the application of a specific tariff scale for the calculation of their component for subscribed power overruns, users provide all elements that justify the actual nature of the work to be conducted on their electricity facilities. When such a request comes from a public distribution system operator and is the result of the request of a user connected to this grid, the public distribution system operator passes the aforementioned elements to the upstream public system operator, and provides the user's maximum power request which will be subtracted from the public distribution system operator's overruns and billed according to the provisions applicable to sporadic scheduled overruns.
The application of this provision is limited for each connection point to a maximum of once per calendar year, for use over a maximum of 14 continuous days. For the breakdown of the number of applications of this provision per connection point, the applications made upon the request of public distribution system operators are not taken into account when they are the result of a request from a user connected to their network. Days which have not been used cannot be carried over.
The public system operator, or where necessary the upstream public system operator, can refuse or suspend application of this provision to a user, due to operating constraints foreseen on their public grid. This refusal or suspension has to be justified and notified to CRE at the same time.

11. Annual reactive energy component (CER)

In the absence of metering systems recording physical flows of reactive energy, public system operators can provide transparent and non-discriminatory methods for estimating these flows in their reference technical documentation.
The provisions in sections 11.1 and 11.2 do not apply to connection points located at the interface between two public electricity grids.

11.1. Withdrawal flows

If physical flows of active energy at a connection point are withdrawal flows, public system operators provide reactive energy free of charge:

- up to the value of the $tg\ \varphi_{max}$ ratio defined in table 19 below, from 1 November to 31 March, from 6:00 a.m. to 10:00 p.m. Monday to Saturday;
- as an exception, for connection points where the user has opted for a tariff with time differentiation, not exceeding the $tg\ \varphi_{max}$ ratio defined in table 19 below, during on-peak winter hours and mid-peak winter hours;

- without limitation outside these periods.

During these periods subject to limitation, reactive energy absorbed in the HTB voltage range beyond the value of the *tg φmax* ratio is billed in line with table 19 below:

Table 19

Voltage range	$tg\ \varphi_{max}$ ratio	c€/kvar.h
HTB 3	0.4	1.33
HTB 2	0.4	1.42
HTB 1	0.4	1.59

11.2. Injection flows

If physical active energy flows at a connection point are injection flows, and the facility is subject to voltage control and the user does not benefit from a contract as provided by article L. 321-11 of the French Energy Code, the user undertakes to maintain the voltage of the facility's connection point within a range determined by the public system operator and set according to the rules published in the reference technical documentation of the public system operator to which the user is connected.

Should the voltage exceed the agreed range, the user is billed according to table 20 below for the difference between the reactive energy that the facility has actually provided or absorbed and the reactive energy that it should have provided or absorbed to maintain the voltage within the range agreed in the operating contract, up to the operating capacities defined by diagrams [U, Q] of the connection contract. These elements are determined according to the rules published in the reference technical documentation of the public distribution system operator.

Table 20

Voltage range	c€/kvar.h
HTB 3	1.33
HTB 2	1.42
HTB 1	1.59

11.3. Specific provisions for the annual reactive energy component between two public electricity system operators

At each connection point shared, the public system operators agree, by contract, on the quantity of reactive energy they exchange, determined according to active energy transits, in compliance with the rules published in the reference technical documentation of the public transmission system operator or, in this operator's absence among the contracting parties, the injecting system operator.

The reactive energy provided above the $tg\ \varphi_{max}$ ratio or absorbed below the $tg\ \varphi_{min}$ ratio is billed per connection point according to table 21 below.

Table 21

Voltage range	c€/kvar.h
HTB 3	1.33
HTB 2	1.42
HTB 1	1.59

The $tg\ \varphi_{max}$ and $tg\ \varphi_{min}$ values of the $tg\ \varphi$ ratio thresholds per connection point are agreed upon by contract per time slot between public system operators.

Failing agreement, the contractual term $tg\ \varphi_{max}$ is equal to the "historical value" defined as the maximum value of monthly $tg\ \varphi$ observed at the connection point during winter in 2006 to 2009, without exceeding 0.4. If, at the date of entry into force of the present tariff rules, the value of this contractual $tg\ \varphi_{max}$ term is higher than the "historical value", the contractual $tg\ \varphi_{max}$ term is gradually decreased to the historical value through annual drops of 0.05. These annual drops cease to apply once the contractual $tg\ \varphi_{max}$ term is lower than or equal to 0.2.
Within a period of one year following the entry into force of the present tariff rules, system operators adapt their reference technical documentation to specify the principles setting the terms for changing this contractual value, taking into account, on the one hand, reasonable possibilities of the public distribution system operator to control the reactive energy withdrawn by its grid, and on the other hand, voltage constraints identified, at a horizon of 5 to 10 years, by the injecting system operator.
By way of exception, two public system operators may conclude agreements based on fixed reactive power thresholds expressed in MVAR per connection point. The reference technical documentation applicable specifies the terms for determining these thresholds and verifying compliance with these thresholds at sufficiently representative intervals. These terms take into account the type of voltage constraints, identified at a horizon of 5 to 10 years, as well as the reasonable possibilities of the public distribution system operator to control the reactive energy supplied or withdrawn from its network.

12. Indexation of the tariff scale

M, the anniversary month of the date of entry into force of the present tariffs.
Each year *N* as from 2014, the level of the components defined by tables 1 to 2.2 and 4 to 21 above, is automatically adjusted on the first day of month *M*, with the exception of the power weighting coefficients of withdrawal components and coefficient *c* in table 4.
The tariff scale in application as of the first day of month *M* of year *N* is obtained by adjusting the tariff scale in application the previous month in line with changes in the consumer price index excluding tobacco and a reconciliation factor for the expense and income clawback account (CRCP).

12.1. Change rule

For the HTB voltage range, the tariff scale is automatically adjusted in line with the following percentage:

$$Z_N = IPC_N + K_N$$

Z_N: percentage of change, rounded off to the nearest tenth of a percent, in the tariff scale in application as from the first day of the month M of the year N compared to that in application the previous month.
IPC_N: percentage of change between the average value of the consumer price index excluding tobacco over the calendar year *N-1* and the average value of the same index over the calendar year *N-2*, as published by the French statistics agency INSEE (identifier: 000641194).
K_N: CRCP clearance factor for year N, calculated on the basis of the CRCP balance as at 31 December of year *N-1* and reconciliations already conducted. The absolute value of the coefficient K_N is limited to 2%.

12.2. Rounding off rules

Rounding off rules are as follows for the adjustment of tariff scales:

- the coefficients of fixed parts of the annual withdrawal components and the annual administrative management and metering components are rounded off to the nearest euro cent;
- the other coefficients subject to adjustment are rounded off to the nearest hundredth of the unit in which they are expressed.

13. Transitional provisions applicable to the tariffs for the HTB 1 and HTB 2 voltage ranges

From the date of entry into force of the present tariffs until the modification of public electricity system access contracts, the terms for modifying subscribed power laid out in these contracts apply for the subscribed power of each time category independently of one another.
During a learning period, starting from the date of entry into force of the present tariffs until 31 March 2014, the rules related to the subscription of withdrawal power and the selection of the tariff option are those described in sections 13.1 and 13.2 below.

13.1. Setting the tariff option and subscribed power

At the beginning of the learning period, the user selects a tariff option.
During this learning period, each month the user sets the subscribed power of each time category.
If the user does not set the subscribed power, the subscribed power of a time category is set by default as the higher of the following two values:

- the value of the subscribed power of this time category for the previous month;
- the average of the 3 levels of power, 10 minutes maximum attained over 3 different days in the month during this time category.

In all cases, the subscribed power must comply with the rule relating to power mentioned in sections 6.1.2 and 6.1.3.
At the end of the calendar year during which the present tariffs enter into force, the user selects subscribed power and a tariff option that will be considered valid from the first day of the learning period. The different tariff components for the period starting from the first day of the learning period to the last day of the calendar year are recalculated using this subscribed power and tariff option.

At the end of the learning period, the user selects new subscribed power and tariff option that will be considered valid from the first day of the learning period. The different tariff components for the entire learning period are recalculated using this new subscribed power and tariff option.

13.2. Application of the "peak shaving in extreme cold weather" clause

If a severe cold spell takes place during the period starting from the first day of the learning period to the last day of the calendar year during which the present tariffs enter into force, the corresponding peak shaving is calculated at the end of the calendar year.

If a severe cold spell takes place during the period starting from the first day of the calendar year following the entry into force of the present tariffs until the last day of the learning period, the corresponding peak shaving is calculated at the end of the learning period.
In accordance with Article L. 341-3 of the French Energy Code, the present deliberation will be published in the *Journal* O*fficiel de la République Française.*

Paris, 3 April 2013

For the French Energy Regulation Commission,

The President,

Philippe de Ladoucette