Report on the approach to setting the key parameters of the regulatory formula and prices for the second regulatory period in the electricity industry

1 Introduction

In 2004, the last year of the first regulatory period, the Energy Regulatory Office ("the ERO" or "the Office") was to prepare the regulation methodology for the following regulatory period and the pricing methodology.

1.1. The first regulatory period

After its establishment in 2001, the ERO opted for a regulation methodology similar to that used by many European regulators, RPI-X, which is based on the utility's performance. The key principle is that revenue caps are set for each of the utilities for a certain predetermined period of time, known as the regulatory period. The other principle is that the regulation method and the revenue caps remain unchanged throughout the regulatory period, with the exception of escalation by the RPI index adjusted by efficiency factor X.

However, in the Czech Republic this was a quite novel approach, because until that time the cost-plus principle of regulation had been used, whereby the utility's costs had been assessed every year and the resulting price set on this basis.

Foreign regulators' experience suggests that the recommended regulatory period last from three to five years. Since a completely different methodological approach to regulation was involved, the ERO opted for a three-year period, from 1 January 2002 to 31 December 2004.

For the first regulatory period, revenue caps were set for each of the companies using a simple basic formula:

$$PV = N + O + Z$$

which has a specific form for regulation in the energy sector:

$$PV_0 = \left[N_0 + O_0 + \left(ROA \times PA_0\right)\right]$$

$$PV_i = PV_{i-1} \times \left(PPI_i - X_i\right)$$

where:

PV_i	allowed revenues in the respective regulated year (revenue cap)
PV_0	the initial value of the allowed revenues
N_0	the initial value of operating costs
O_0	the initial value of depreciation and amortisation
ROA	return on operating assets (a measure of profit)
PA_0	the initial value of operating assets
PPI_i	industrial producers price index in the respective regulated year
X_i	the efficiency factor in the respective regulated year

This approach helped to ensure the energy industries' stability throughout the regulatory period, both for the final customers and investors. At the same time the regulator assumed a detached view of regulation as it did not calculate the various parameters of the regulatory formula every year. However, also the negative aspects of the formula should be admitted – the fact that the actual values of the various parameters achieved by the companies developed differently from the parameters of the formula, which were indexed by the regulator.

Pluses	Minuses and mistakes
1. The formula was simple and its advantage consisted in providing a sort of a detached view of the whole issue. 2. The formula guaranteed for the regulator, certainty of development and stability of the prices in the sector. 3. The formula incentivised companies to cost savings.	1. The development of actual costs, depreciation and assets did not correspond with the values of these parameters set by the regulator (actual development differed mainly in respect of assets). 2. Too short a regulatory period. 3. The artificial allocation between trading and distribution made it possible for inaccuracies to arise in the regulation.

Based on the above experience, and its analyses of the benefits and shortcomings of this approach, the regulator has decided to maintain the basic approach to regulation, but adopted certain modifications to this approach.

1.2. The regulator's general approach to the conditions for the second regulatory period

Objectives of the second regulatory period

The following key objectives were set for the preparations for the second regulatory period:

- As the regulatory periods roll over, ensure stability in the sector, i.e. stable prices to the final customers while maintaining the quality of the supplies and, at the same time, profitability for investors;
- Prepare a method based on generally accepted principles;
- Incentivise the regulated entities to improve their efficiency throughout the regulatory period;
- Work more with investments throughout the regulatory period.

The regulatory period

A significant change is the fact that the second regulatory period will last for five years, from 1 January 2005 to 31 December 2009. It turned out in the first regulatory period that three years were too short a time to feel the effects of incentive regulation, because, in line with the theory of regulation, the data for the last but one year of the regulatory period serves as the basis for setting the parameters for the subsequent regulatory period.

The regulatory formula

Another change, and probably even more significant, is the change of the regulatory formula. The fundamental difference is the separate approach to each of the parameters in the regulatory formula.

At the same time, formulas differing in certain details had to be employed for the various regulated activities, thereby reflecting their inherent specifics.

Electricity transmission

$$PV_i = N_0 \times (1-X)^i \times \prod_i \frac{(p_{MI} \times MI + (1-p_{MI}) \times PPI)}{100} + O_0 + \sum_i \Delta O_i + WACC_{NHBT} \times \left(RAB_0 + \sum_i \Delta ZHA_i \right)$$

Electricity distribution

$$PV_i = N_0 \times (1-X)^i \times (1+p\times(r_i-1)) \times \prod_i \frac{(p_{MI} \times MI + (1-p_{MI}) \times PPI)}{100} + O_0 \times (1+p\times(r_{dpi}-1)) \times \prod_i \frac{PPI}{100} + WACC_{NHBT} \times \left(RAB_0 + \sum_i \Delta ZHA_i \right)$$

Pluses	Minuses and mistakes
1. For the regulator, the formulas guarantee a certainty of development, and 90% stability in the sector (the regulator influences the costs and depreciation, and fixes the nominal return for five years). 2. The formulas reflect the gradual reporting of profit related to assets throughout the regulatory period, and prevent a dramatic increase at the beginning of the next regulatory period; supervision over investments in the sector. 3. The rate of return is set using WACC. 4. The methodology preserves the sector's profitability from the first regulatory period, through the year zero method. 5. The year zero method revalues companies and provides an option to use this revaluation in the case of different revaluations during unbundling.	1. The formulas are more complex. 2. Talks have resulted in different formulas for each of the activities. 3. A change in assets requires a special methodology for reporting changes in assets, and changes in reporting (needs to be covered in a public notice). 4. Changes in assets will result in reporting a higher profit during the regulatory period, which may cause the price to rise

The regulator's approach to developing the various formulas and their parameters for electricity transmission and electricity distribution is described in the following chapters.

Communication with regulated entities

The regulator was obliged to declare the parameters for each of the regulated activities well in advance before the beginning of the second regulatory period. The exact dates for setting the parameters are laid down in Public Notice No. 438/2001, as amended, which lays down the content of financial information and the procedures for price control in the energy sector, and are as follows:

- for electricity transmission licence holders seven months before the beginning of the regulatory period;
- for electricity distribution licence holders five months before the beginning of the regulatory period.

In line with the principles of a transparent and open approach to the development of the regulatory methodology and specific regulatory instruments, and to prepare a widely accepted method, the ERO prepared presentations of its views of the way in which the parameters should be defined; it started presenting these views to the various regulated entities as early as the beginning of April 2004. The companies had opportunities for commenting on the regulator's positions, and offer their own observations.

Following up on the start of the communication focused on the conditions for the second regulatory period, the owners of these regulated entities, authorised to represent licence holders in further dealings with the ERO, initiated contacts with the ERO.

2 Description of the final parameters for each of the regulated activities in the second regulatory period

2.1 Electricity transmission

Electricity transmission is a specific activity, and also the position of the Czech transmission system operator, ČEPS, a.s. [‘ČEPS’] differs from that of the distribution companies.

The final formula setting the revenue cap for the electricity transmission activity:

$$PV_i = N_0 \times (1-X)^i \times \prod_i \frac{(p_{MI} \times MI + (1-p_{MI}) \times PPI)}{100} + O_0 + \sum_i \Delta O_i + WACC_{NHBT} \times \left(RAB_0 + \sum_i \Delta ZHA_i \right)$$

PV_i	allowed revenues in the respective regulated year
i	serial number of the respective regulated year
N_0	the initial value of operating costs
O_0	the initial value of depreciation and amortisation
RAB_0	the initial value of the operating assets
$WACC_{NHBT}$	rate of return
X	efficiency factor
MI	wage escalation index
PPI	industrial escalation index (industrial producers price index)
p_{MI}	wage escalation index coefficient
ΔO_i	change in depreciation and amortisation in the respective regulated year
ΔZHA_i	change in the regulatory asset base in the respective regulated year

The above parameters of the formula are described in the following sections.

2.1.1 Allowed costs

The electricity transmission licence holder’s allowed costs in the second regulatory period are defined as follows:

Allowed costs include:

- operating expenditure required to carry out the licensed activity,
- insurance policies on assets and third-party liability,
- bank fees.

Allowed costs do not include:

- costs not allowable against tax,
- interest on loans and lease margins,
- costs of setting aside and releasing reserves,
- lease payments,
- other financial and extraordinary costs.

In the case of ČEPS, the regulator has decided to set the input values of the allowed costs for the second regulatory period on the basis of the resulting values from the last closed fiscal year, i.e. the actual costs of 2003. The decision to use the actual costs was motivated by the fact that in the first regulatory period the company was efficient and kept the values prescribed by the regulator.

This value was adjusted by an escalation factor composed of the 2004 industrial escalation index and wage escalation index, and the general efficiency factor, to yield the input value applicable to the first year of the regulatory period, N_0.

2.1.2 Depreciation and amortisation

The depreciation and amortisation [‘depreciation’] included in the regulatory formula is based on the book value of the company’s operating assets. To determine the amount of depreciation, accounting depreciation rates are used.

The 2003 accounting depreciation was used as the input value for the second regulatory period.

According to economic theory, depreciation is to enable the company to cover the costs of operating asset replacement so that the assets’ net book value does not decline. However, in the specific case of ČEPS recent investments had been lower than accounting depreciation, and there is a certain risk that this trend will continue. The regulator has therefore decided that during the second regulatory period it will not adjust depreciation by the escalation factor but by changes in the value of depreciation, whereby the formula will at all times include its actual value. The company will therefore be motivated to reinvest at the level of accounting depreciation to maintain the value of its operating assets (and, in turn, its profit), which will ensure the quality and reliability of the services provided to the final customers.

2.1.3 Profit

For the second regulatory period the profit parameter has been defined as the product of the rate of return times the value of the regulatory asset base.

Rate of return

The rate of return has been set for the second regulatory period on the basis of the generally accepted methodology for computing weighted average cost of capital, WACC. The methodology is described in Chapter 4 of this report.

For ČEPS the following values have been set:

Formula parameter	Value
r_f = risk-free rate of return	4.18%
$ß_{unlevered}$ = unlevered beta factor	0.250
$ß_{levered}$ = levered beta factor	0.296
ERP (or $r_M - r_f$) = market risk premium	6.32%
D = debt	20%
E = equity	80%
T = tax rate	26.0%
r_d = cost of debt	4.68%
r_e = cost of equity	6.05%
$WACC_{NHAT}$ - nominal value (after tax)	**5.534%**
Corporate income tax	26.0%
$WACC_{NHBT}$ - nominal value adjusted to tax (before tax)	**7.479%**

Regulatory asset base

The regulatory asset base is the base to which the rate of return is applied. The basis for determining its value is operating assets, the definition of which is set out in Section 4 of Public Notice No. 439/2001, as amended.

In the case of ČEPS, when this company was formed (through a demerger into a newly established subsidiary owned by ČEZ, a.s.) in 1998 the book value of its assets was revalued. The Office has therefore decided to use the net book value of the operating assets serving to carry out the licensed activity for setting RAB. It has decided to use the value of the operating assets from the last closed fiscal year preceding the regulatory period, i.e. 2003, as the input value for the second regulatory period.

The reinvestment issue presents the same problem as depreciation, i.e. there exist certain expectations that in the company's books, the value of operating assets will decline due to insufficient investments. The RAB value will be adjusted every year by changes in the net book value of operating assets. This step will motivate ČEPS to reinvestments maintaining RAB at a level preventing its profit from declining during the regulatory period.

2.2 Electricity distribution

For electricity distribution the following final formula to compute allowed revenues has been developed:

$$PV_i = N_0 \times (1-X)^i \times \prod_i \frac{(p_{MI} \times MI + (1-p_{MI}) \times PPI)}{100} + O_0 \times \prod_i \frac{PPI}{100} + WACC_{NHBT} \times \left(RAB_0 + \sum_i \Delta ZHA_i \right)$$

PV_i	allowed revenues in the respective regulated year
i	serial number of the respective regulated year
N_0	initial value of operating costs
O_0	initial value of depreciation and amortisation
RAB_0	initial value of operating assets
$WACC_{NHBT}$	rate of return
X	efficiency factor
MI	wage escalation factor
PPI	industrial escalation factor (industrial producers price index)
p_{MI}	wage escalation factor coefficient
ΔZHA_i	change in the value of the regulatory asset base in the respective regulated year

2.2.1 Allowed costs

The costs allowed electricity distribution licence holders in the second regulatory period are defined as follows:

Allowed costs include:

- operating expenditure required to carry out the licensed activity,
- insurance policies on assets and third-party liability,
- bank fees and charges.

Allowed costs do not include:

- costs not allowable against tax,
- interest on loans and lease margins,
- costs of setting aside and releasing reserves,
- lease payments,
- other financial and extraordinary costs.

The generally applied theory of regulation puts forth that the costs entering the following regulatory period are determined on the basis of analysing the values actually achieved in the preceding period. However, this theory assumes that companies reduce their costs under the pressure for efficiency during the regulatory period, thereby achieving higher profits than set for them by the regulator.

In reality, most of the distribution companies did not reduce their costs, and even exceeded the value set for them, contrary to the above theory.

The fact that the companies exceeded the value of the regulated costs placed the regulator in a position where it had to select a different methodology, i.e. decide the level at which it would set the costs for the second regulatory period. Had the regulator opted for the alternative based on the values actually achieved for the last complete year preceding the second regulatory period, the price to final customers would have increased sharply. Another alternative available to the regulator was to modify certain selected cost items on the basis of analysing the costs of the first regulatory period. To carry out such a detailed analysis of all costs of all companies and then to defend the outputs from the analysis was beyond the Office's capacities. The regulator has therefore opted for the methodology described in the following paragraph.

The fundamental principle is that the companies had been aware of the set levels beforehand, and were expected to adjust their costs. The regulator therefore proceeded from this known value, which it escalated, in line with the rules of the first regulatory period, by PPI and the efficiency factor for 2000 to 2002; for 2003, which saw deflation, the escalation factor of 100 was applied in line with the rules for the second regulatory period; in the end an escalation factor composed of PPI and MI for 2004 was applied, and the general efficiency factor. This process resulted in the input value for the first year of the second regulatory period, N_0.

2.2.2 Depreciation and amortisation

Public Notice No. 439/2001, as amended, sets out for each of the activities the depreciation and amortisation ['depreciation'] rates applicable to selected types of operating assets. Operating asset depreciation rates for electricity distribution are set out in Appendix No. 2 to Public Notice No. 439/2001, as amended.

Accounting depreciation for the last closed fiscal year preceding the regulatory period, i.e. for 2003, served as the input to the calculation of this parameter. The reason is that this represents depreciation of the company's existing operating assets, which generates the funds for the necessary replacement of these assets through reinvestment.

This value was adjusted by the industrial escalation factor, PPI for 2004, to yield O_0, and it will be adjusted in the same way in the following years of this regulatory period, i.e. without applying the efficiency factor.

2.2.3 Profit

For the second regulatory period the electricity distribution profit parameter has been defined in the same way as for electricity transmission, i.e. as the product of the rate of return times the value of the regulatory asset base.

Rate of return

In the first regulatory period the Office set the rate of return as the rate of return on operating assets. For the second regulatory period it decided to determine the rate of return on the basis of the generally accepted methodology for computing weighted average cost of capital, WACC. The methodology is described in Chapter 4 of this report.

For electricity distribution the following values have been set:

Formula parameter	Value
r_f = risk-free rate of return	4.18%
$ß_{unlevered}$ = unlevered beta factor	0.350
$ß_{levered}$ = levered beta factor	0.461
ERP (or $r_M - r_f$) = market risk premium	6.32%
D = debt	30%
E = equity	70%
T = tax rate	26.0%
r_d = cost of debt	4.68%
r_e = cost of equity	7.09%
$WACC_{NHAT}$ - nominal value (after tax)	**6.004%**
Corporate income tax	26.0%
$WACC_{NHBT}$ - nominal value adjusted to tax (before tax)	**8.114%**

Regulatory asset base

The regulatory asset base is the base to which the rate of return is applied. The basis for determining its value is operating assets, the definition of which is set out in Public Notice No. 439/2001, as amended.

Since one of the ERO's basic objectives for the second regulatory period was to maintain the profitability of the sector as a whole, i.e. maintain the conditions for investors who had entered the sector in the preceding period, the method of asset revaluation had to be selected. This need followed from the change of the methodology and, in turn, the level of the rate of return applied in comparison with the first regulatory period.

There are many approaches, differing as to their time and cost intensity, to asset valuation. The regulator has opted for the method based on the above principle of maintaining the sector's profitability. The value of the regulatory asset base has been determined on the basis of the historical reasonable profit.

The initial value of RAB for electricity distribution in the second regulatory period has been calculated as follows:

$$RAB_{2000} = \frac{profit_{2000}}{WACC_{NHBT}}$$

$$RAB_{2005} = RAB_{2000} + \sum_{2001}^{2005} \Delta ZHA$$

By including $\sum_{2001}^{2003} \Delta ZHA$ the value of the regulatory asset base for 2001-2003 was augmented by the actual values of the change in the net book values of operating assets, and for 2004-2005 $\frac{2}{3} \times \sum_{2001}^{2003} \Delta ZHA$. For the following years of this regulatory period a methodology for recognising ΔZHA will be developed the difference between the reflected value and the actual value of the capitalised assets in the respective regulated year will be adjusted by the Office through the correction factor.

3 Coefficients adjusting the key parameters of the regulatory formula

For activities in the electricity industry, the Office has adopted the same approach to the coefficients adjusting each of the parameters and the way of their application in the regulatory formula.

3.1 Escalation factor

The industrial escalation factor has been defined as the industrial producers price index, and is applied to both costs and, in the case of distribution, depreciation and amortisation ['depreciation']. The Office has determined that in the event of deflation (PPI<100) the industrial escalation factor will not be used, or rather, it will equal 100. The industrial escalation factor accounts for 85% of the overall escalation factor applied to costs in electricity transmission, and for 65% in electricity distribution (1 - wage escalation factor coefficient). In electricity distribution, it has a 100% weighting when applied to depreciation.

Another major change introduced by the Office for the second regulatory period is the *wage escalation factor*, which reflects a different development of the wages that are included in allowed costs than the industrial escalation factor. It is applied only to costs, and its weighting in the regulatory formula corresponds to the wage escalation factor coefficient. The wage escalation factor accounts for 15% of the overall escalation factor in electricity transmission, and for 35% in electricity distribution (the wage escalation factor coefficient).

3.2 Efficiency factor X

This coefficient limits the escalation factors' influence on costs, making the utilities operate more efficiently and reduce costs, which do not copy price rises thanks to the X factor.

For the whole five-year second regulatory period the Office has set a single efficiency factor for electricity utilities; the factor imposes an overall reduction in costs by 10%. This implies that the annual value is calculated as follows:

$$X = 1 - \sqrt[5]{0,9} = 2,085\%$$

3.3 Correction factor K

The principle on which the correction factor is applied can be described, in a somewhat simplified way, as an adjustment of the actual revenues generated by the provider of a certain service to the value of the allowed revenues set by the regulator.

The correction factor for the respective year is the difference between the actual revenues for the regulated year, which are the result of the price (calculated as the ratio of allowed revenues over the planned technical units) times the actual technical units, and the allowed revenues.

Allowed revenues for the following regulated year are adjusted by this factor.

Since the correction factor only influences the allowed revenues with a delay of two years, the application of this factor reflects the time value of money. The correction may have a positive or negative direction, and in both cases the time value of money is the same. This prevents the potentially speculative approach to the inputting of the planned values.

Note: For the electricity industry, the exact methodology for determining the correction factor is set out in Appendix No. 9 to Public Notice No. 438/2001, as amended.

4 Method of computing the rate of return - WACC

1 $$WACC_{NHBT} = \frac{WACC_{NHAT}}{1-T}$$

2 $$WACC_{NHAT} = r_e \times \frac{E}{E+D} + r_d \times (1-T) \times \frac{D}{E+D}$$

3 $$r_e = r_f + \beta_L \times ERP$$

4 $$r_d = r_f + CS$$

5 $$\beta_L = \beta_{unL} \times \left[1 + (1-T) \times \frac{D}{E}\right]$$

Nominal $WACC_{NHBT}$, which is used in the formula for allowed revenues, is computed from $WACC_{NHAT}$ by augmenting it by the income tax so as to make the actual profit left to companies after taxation reach the level set by the regulator.

Nominal $WACC_{NHAT}$ has been computed as a weighted average of the cost of equity and cost of debt, while the volume of these components of capital constitutes the weights. Moreover, the cost of debt has been reduced by the rate of taxation because interest on debt is included in tax allowable costs, and therefore works here as a tax shield.

Cost of equity, r_e

The cost of equity has been expressed as the sum of the risk-free rate r_f and a part of the market risk premium ERP, which is determined by the value of factor β_L.

Cost of debt, r_d

The cost of debt has been expressed as the sum of a risk-free rate of return (r_f) of 4.18% and a credit spread (CS) of 0.5%. The credit spread expresses the interest premium that reflects the rate of risk inherent in the investment.

Equity to debt ratio, E/D

The Office has decided to set the equity to debt ratio with at a level intended to encourage a greater use of debt, the cost of which has been lower than the cost of equity. In the light of the current capital structure of regulated companies, the extent of debt financing has been set relatively low in comparison with other countries.

Tax rate, T

The Office has decided to keep WACC unchanged over the regulatory period; it will only be adjusted in the case of a change in the income tax rate.

Risk-free rate of return r_f

The risk-free rate of return has been calculated on the basis of five-year bonds (2004 – 2009), in view of using the nominal value of WACC throughout the five-year regulatory period. These considerations suggest a greater certainty for investors in their planning of the return on investment for the whole regulatory period – fixed for five year.

The risk-free rate of return has been calculated on the basis of the yield from government bond CZ0001000855, issue number 42, tranche number 4. This is a five-year government bond whose maturity (2004 – 2009) best matches the length of the second regulatory period.

Factor β_{unL}

This factor has been derived from an average of β factors used by publicly traded European distribution companies, and fully corresponds to the values that the regulatory authorities in the UK, the Netherlands and Austria have decided to use.

Factor β_L

For use in the calculation of the cost of equity, factor β_{unL} had to be adjusted (weighted) depending on the gearing of the particular company and the rate of taxation applicable to the company.

Market risk premium, ERP

The market risk premium has been quantified on the basis of the values achieved on US capital markets since 1928. The US market risk premium has then been augmented by the country's risk premium derived from the Czech Republic's rating.

5 Pricing methodology

Since 1 January 2005 the Office has been regulating the prices of the following activities:

a) electricity transmission over the transmission system,
b) system service provision,
c) electricity distribution to eligible customers at the various voltage levels,
d) the market operator's activities, broken down in accordance with a separate legal regulation (Public Notice No. 373/2001, as amended, which lays down the rules for electricity market organisation and the principles of pricing the market operator's activities),
e) electricity generation in plants not connected to the transmission system,
f) electricity generation from renewable sources,
g) electricity generation from combined heat and power generation,
h) electricity supply to protected customers at the low voltage distribution level,
i) electricity supply by the supplier of last resort.

The regulation of the above activities takes the following forms:

- activities under a) to e)
  - the prices are set individually for each licence holder,
  - they are regulated in the form of prices set officially as fixed prices;
- activities under f) to g)
  - they are regulated in the form of prices set officially as minimum or fixed prices,
  - the support for renewable energy sources and combined heat and power generation ("cogeneration") takes the form of a fixed premium to a contract price (not subject to control), and compulsory purchase of electricity at the minimum prices;
- activities under h) to i)
  - they are regulated in the form of prices set officially as minimum prices.

The resulting price of electricity supply to final customers comprises the components listed under points a) to g), and the unregulated price for energy. In the case of eligible customers, the price of energy is fully subject to contract between the customer and supplier, without any influence by the Office. In the case of protected customers, it is included in the rates as the average purchase price set by the Office.

5.1 Electricity transmission

In electricity transmission price control, the second regulatory period sees a change in the scope of the regulated activities, whereby all licensed activities carried out by ČEPS are regulated. Regulation 1228/2003/EC has had a significant influence on the method of controlling the prices in the transmission system, by not allowing to charge exports at all. At the same time it allows to regulate the activities of, and proceeds from, the process of capacity allocation on cross-border sites, thanks to which a part of these proceeds from the auctions is used for reducing the TSO's allowed revenues, which has been reflected in a lower price for capacity booking.

The Office has made use of this opportunity, and included the proceeds from auctions of cross-border transmission capacity, which activity was not regulated in the first regulatory period, in the regulation in the second regulatory period as follows:

a) a part of the auction proceeds is included in the company's allowed revenues from transmission with a view to reducing them overall, and in turn reducing the resulting price for transmission;

b) a part of the auction proceeds is intended to pay the TSO's costs related to the ITC mechanism (ITC = Inter-TSO Compensation), in connection with the compensations that are paid between TSOs in the EU member states for the use of the transmission system by other transmission system operators;

c) a part of the proceeds will serve as a provision for covering the potential loss incurred in the other regulated activities of ČEPS, and also to strengthen and develop the TSO's cross-border sites.

The object of regulation is the TSO's allowed revenues, which are given by the sum of the allowed costs, depreciation and amortisation, and profit. The allowed revenues are reduced by a part of the auction proceeds (see above); the Office has set this part as a constant amount throughout the second regulatory period.

5.1.1 Charge for capacity booking

The charge for capacity booking is computed from the allowed revenues and the annual booked capacity for customers taking electricity from the transmission system. The basic criterion for allocating allowed revenues per unit of booked capacity is the maximum loads caused by customers connected to the transmission system (distribution companies and final customers); the input to this calculation is the average of the net balances of the hourly maximums of demand taken from the transmission system in the four winter months (November to February) for the three preceding periods. Reverse flows into the transmission system are taken into account in the calculation.

5.1.2 Charge for transmission network use

The charge for transmission network use is calculated from the TSO's variable costs and the electricity quantity planned to be transmitted (without exports and transit). The TSO's variable costs are set on the basis of the permissible amount of losses in the transmission system, and the average purchase price of the electricity to cover these losses.

A detailed electricity transmission pricing procedure (charges for capacity booking, charges for network use) is set out in Appendix 1 to Public Notice No. 438/2001, as amended.

The Office evaluates the results of regulation for the respective fiscally closed calendar year, and on this basis applies the appropriate corrections that are reflected in the charge for transmission services in the following regulated year, taking into account the time value of money. In the case of transmission, the variable component of the charge is subject to correction: in this case the correction is applied to the loss rate achieved in the transmission system and the profit/loss attributable the actual prices of the electricity bought to cover losses in the system. The revenues from capacity booking in transmission networks are not subject to correction.

5.2 System services

System services are necessary for ensuring a power balance between electricity generation and electricity consumption, and in turn the stability of the whole electricity system. The TSO is able to provide these services by purchasing ancillary services.

The principle of pricing system services is based on the costs of the ancillary services with the help of which ČEPS provides for the grid's stability. However, there are many factors that may considerably influence the overall costs of ancillary services in a regulated year, such as:

- the price of energy, from which the prices of the ancillary services offered derive,
- the expected construction of wind power plants in the Czech Republic, which occasion higher requirements on the provisions for ensuring the grid's stability, and therefore increased costs of ancillary services,
- the level of electricity exports and imports.

On the other hand, the TSO has various instruments by means of which it can achieve the savings specified by the Office in respect of the costs of ancillary service procurement. These instruments include, for example, long-term (multi-annual) contracts for the purchase of these services, which constitute some guarantee of a certain level of the costs of ancillary services over the long haul.

The charge for system services is computed by dividing total costs by the electricity quantity planned to be transmitted. A detailed system service pricing procedure is set out in Appendix 2 to Public Notice No. 438/2001, as amended.

Similarly as with transmission, the Office evaluates the results of the regulation in the provision of system services, and applies the appropriate correction on this basis; these are reflected in the system service prices in the following regulated year, taking into account the time value of money.

5.3 Electricity distribution

For the purposes of electricity distribution price control, or rather regulation of the revenues from this activity, the distribution system is broken down into the following parts:

- extra high voltage distribution network (VVN),
- high voltage distribution network (VN),
- low voltage distribution network (NN).

Similarly as with transmission, the components of the charge for distribution have been specified for distribution at the VVN and VN levels: the charge for capacity booking and the charge for network use.

5.3.1 Charge for capacity booking

The charges for capacity booking at each of the distribution levels are set on the basis of the distribution company's allowed revenues divided by the number of technical units (i.e. the total capacity, in MW, booked for a customer – final customers and local distribution systems – for the respective regulated year). Pricing at the lower voltage levels (VN and NN) also takes into account the transformation to lower voltage levels (VVN/VN and VN/NN). This is the approach to pricing capacity booking at the VVN and VN distribution levels; at the NN level the procedure differs slightly (the principle of pricing distribution at the NN level is described below).

5.3.2 Charge for network use

The charge for network use covers a DSO's variable costs incurred in electricity transport through the distribution system. For the second regulatory period the Office has opted for regulating variable costs by setting the permissible rate of losses at the respective voltage level in the distribution system, which includes the permissible rate of technical losses, constant throughout the regulatory period, and the permissible rate of commercial losses with a predefined degressive nature over the same period. The permissible rates of technical and commercial losses are set individually for each of the DSOs, while the rate of reducing commercial losses during the second regulatory period is applicable to all DSOs and has been set at 2.085% a year (i.e. 10% for the whole regulatory period).

A DSO's variable costs at the respective voltage level are determined on the basis of the permissible level of overall losses and the average purchase price of the energy intended to cover the losses in the system, which is set by the Office and is further used as input to the pricing of electricity supplies for protected customers. These costs are then divided by the total planned quantity of the electric energy to be distributed at the respective voltage level, and the result is the charge for the use of the networks at that distribution level.

Since electricity is transported to the customers at different levels of the electricity transport system (the transmission system, and the various voltage levels of the distribution system), the charges for network use at lower voltage levels therefore also cover the variable costs at the higher voltage levels of the distribution and transmission systems.

A detailed distribution service pricing procedure is set out in Appendices 3 and 4 of Public Notice No. 438/2001, as amended.

For the second regulatory period the Office has introduced a single-component price for using the networks of regional distribution system operators at the VN level for irregular short-term loads. The price has been set so as to make its use advantageous for eligible customers at the high voltage level, where the maximum load lasts for less than 300 hours a year. For longer maximum loads, the two-component distribution charge (for capacity booking and for network use) is more suitable for final customers.

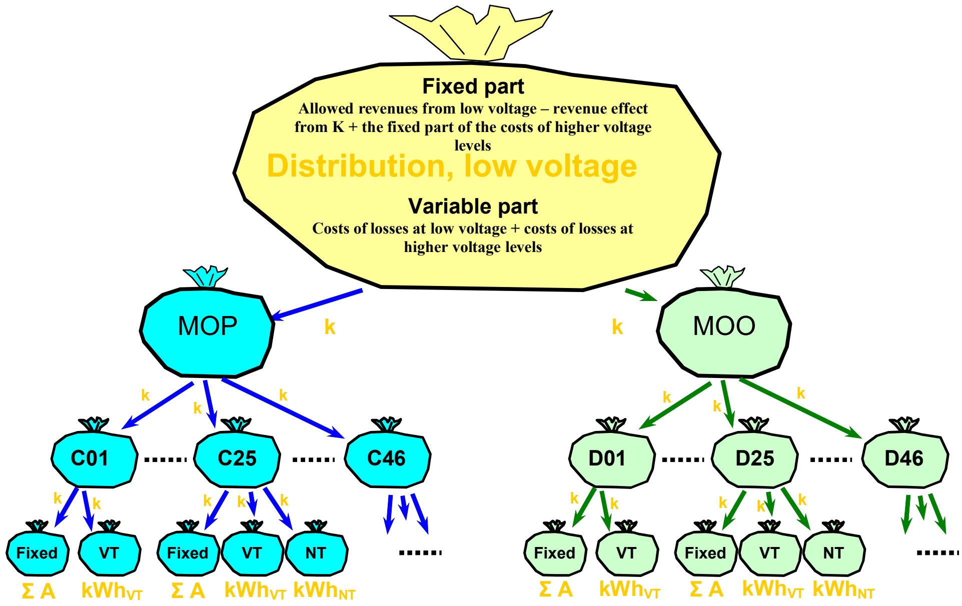
5.3.3 Distribution charges at the low voltage distribution levels

As the electricity market liberalisation progresses, whereby all final customers, with the exception of households, became eligible customers on 1 January 2005, the question of distribution tariffs at the low voltage level has had to be tackled. The viable approach to distribution tariffs at the low voltage level consists either in adopting the same principle of pricing as on the extra high voltage and high voltage levels (i.e. one two-component stamp for each level – the system of capacity booking and network use charges), or in differentiating the prices for distribution services at the low voltage level depending on the nature of the demand, and maintaining a rate structure similar to the existing structure. In the first regulatory period, when all final customers connected to the low voltage level were protected customers, a cumulative single-component charge for electricity distribution entered into the calculation of the resulting rates.

Since the system of only one two-component price would do away with the motivation for the customers to make flexible demand control possible to the DSO, the purpose of such demand control being to maintain the stability of the distribution system, and also because completely different relations would arise in comparison with the existing tariff rates at the low voltage level, the Office has decided to differentiate the prices for distribution services on the basis of the requirements placed on network use by loads.

In the second regulatory period, distribution pricing at the low voltage level consists in a progressive allocation of the total costs of distribution (both the fixed part – allowed revenues, and the variable part – variable costs) which need to be covered through distribution tariffs. Fig. 1 illustrates the principle of this allocation.

Fig. 1 – Principle of allocating a distributor's revenues to distribution rates



VT High tariff rate

NT Low tariff rate

The allocation of the total costs to the MOP [low-demand business] and MOO [low-demand households] segments is based on the principle of maintaining the current relations between the prices to both categories. The costs already allotted to each of the customer categories at the low voltage level are allocated to each of the distribution tariffs on the basis of the consumption thresholds[1)], and the allocation reflects the current relations between tariffs. Furthermore, the costs allocated to a respective distribution tariff were broken down to a fixed part (charge for the circuit breaker) and a variable part (charge for the distributed electricity quantity); dividing them by the sum of the respective technical units (A, MWh) yields unit prices for input power and unit prices for distributed quantity (differentiated as the high tariff rate, VT, and the low tariff rate, VT, for double-rate tariffs).

The rate statistics for the last fiscally closed calendar year[2)] serve as the primary basis for the progressive allocation of total costs as depicted in Fig. 1. The resulting prices for the regulated year are then set on the basis of the rate statistics after proportional adjustment to the final customers' consumption expected in that year (i.e. the year for which the prices are set).

[1)] Thresholds are understood to be the annual consumption levels at which it is financially advantageous for the consumers to switch from one distribution tariff to the nearest distribution tariff.

[2)] Rate statistics are understood to be an overview (statistics) of final customers' electricity consumption in the respective tariff, differentiating between the low tariff rate and the high tariff rate, and, possibly, the peak tariff rate; rate statistics also contain details on the number of demand take points and invoiced sales in the respective tariff. Rate statistics are maintained in a breakdown reflecting the size of the circuit breaker.

The Office evaluates the results of regulation for the respective fiscally closed calendar year, and on this basis applies the appropriate corrections. In the case of distribution, the fixed component of the charge is subject to correction: in this case the correction is applied to the total revenues achieved by the distributor in excess of the allowed revenues set by the Office for that calendar year; this difference is included in allowed revenues for the following regulated year, taking into account the time value of money. The distributor's variable costs (or the revenues from the network use charge) are not subject to correction because the permissible loss rate is defined as a flat rate. Potential positive and negative differences from this flat rate are to the DSO's account.

5.4 Activities of Operátor trhu s elektřinou, a.s.

The initial charge for the market operator's activities in 2005 has been calculated on the basis of allowed revenues (consisting of allowed costs, depreciation and amortisation, and profit) and electric energy consumption of final customers in the Czech Republic, including generators' local consumption. This price will be adjusted by PPI in each year of the second regulatory period.

Besides the clearing charge (in CZK/MWh), the regulated prices for the market operator's activities also include the following:

- charge for the registration of the entity subject to clearing,
- annual charge for clearing,
- charge for providing actual values to the electricity market participants,
- charge for the electricity quantity traded on the on-the-day market organised by the market operator.

For the second regulatory period, the charge for the market participants' initial registration has been abolished for electricity generation, distribution and trading licence holders.

5.5 Electricity generation in plants not connected to the transmission system (distributed generation)

The generating plants that are not connected to the transmission system but are connected to one of the distribution system levels (distributed generation, or decentralised generation) spare the TSO's variable costs, or, as the case may be, the DSO's variable costs at higher voltage levels, incurred in transporting electricity through the respective part of the grid (the transmission system, or a certain voltage level of the distribution system).

The fixed prices that have been set for distributed generation as a premium to the market electricity price negotiated between the generator and customer/trader, have been calculated on the basis of the philosophy of the cost savings achieved at higher voltage levels thanks to the fact that the electricity is supplied to a lower distribution level. The respective regional distribution system operator to whose facilities the generating plants are connected, pay these prices to the generators.

The distributed generation charges cause DSOs to incur extra costs. These extra costs are reflected in prices to final customers in the form of a contribution for distributed generation; this contribution is calculated by dividing the DSO's total extra costs by the total consumption of the consumers connected to its distribution system. The contribution for distributed generation differs by the region (the Office sets it individually for each regional distribution system operator). Unlike the first regulatory period, when the contribution for distributed generation was differentiated by the distribution level, in the second regulatory period it is a single contribution disregarding the voltage levels. Final customers pay the contribution in the charge for electricity distribution.

The results of the above support for distributed generation are subject to correction by the regulator – they are adjusted to reflect the actual values achieved in the last fiscally closed calendar year, taking into account the time value of money.

5.6 Electricity generation from renewable energy sources and CHP

5.6.1 Support for electricity generation from renewable sources

In its EU accession treaty, the Czech Republic undertakes to achieve an indicative target of an 8% share of electricity generated from renewable sources in gross electricity consumption by 2010. Because of its lower competitiveness in comparison with coal-fired or gas-fired plants, financial support is necessary for generation from renewable sources.

The support scheme is provided for in the bill on support for renewable energy sources. The generator will be able to opt for a system based on mandatory purchase of electricity generated from renewable sources for a certain minimum purchase prices (DSOs and the TSO are responsible for purchasing this electricity), or a system based on green premiums (premiums to market prices).

Pending the complete opening of the electricity market (i.e. until 31 December 2005), support for renewable sources in the form of the minimum purchase prices will be maintained, with the exception of electricity generation by co-firing – common burning of fuel mixtures of white, brown or dedicated biomass and fossil fuels. In accordance with the bill on support for renewable energy sources, fixed electricity purchase prices have been set (in CZK/MWh) as a form of a premium to the market price negotiated between the respective generator and the customer/trader.

Minimum purchase prices of electricity from the various types of renewable sources are set in relation to the capital and operating expenditure incurred by each of the categories of plants. The calculation is based on the method of the net present value of the cash flows generated by the projects (NPV CF) over the service life of the equipment equalling zero at a discount rate of 7%. In its pricing approach, the Office preserves the profitability of each of the categories of plants, which is reflected in price differentiation by the date of plant commissioning. Price differentiation is the result of changes in capital and operating expenditure caused by the development of the technologies used.

Distribution companies incur extra costs due to the support for renewable energy sources, which are attributable to the difference between the electricity price for these plants and the electricity price for other, non-renewable (not supported) technologies. These extra costs are reflected in the prices to final customers in the form of a contribution for electricity generation from renewable sources. The resulting contribution is influenced by the quantity, and structure of generation, of electricity from renewable sources, the level of support granted to these sources (purchase prices, premiums) and the price of energy on the electricity market, which together define overall extra costs related to these plants, and also by total electricity demand by all customers (including generators' local demand), to which overall extra costs are allocated. The contribution is uniform throughout the country.

For a fiscally closed calendar year, the actual income from the contribution covering the extra costs incurred in purchasing electricity from renewable sources is compared against the actual costs incurred in purchasing electricity from these plants, and then adjusted. The adjustment is reflected in the prices in the following regulated year, taking into account the time value of money.

5.6.2 Support for electricity generation from cogeneration

Combined heat and power generation is an important element of environmental protection. Using the heat primarily intended for electric energy generation helps to achieve significant fuel savings in comparison with purely electricity or purely heat generating operations. It is therefore important to afford preferential treatment to this area of environmental protection in financial terms.

In the first regulatory period cogeneration was supported both by minimum purchase prices and fixed premiums to the market price negotiated between the generator and customer. In both cases the distribution system operator is obliged to purchase electricity from cogeneration plants.

For the first year of the second regulatory period, the supported plants have been categorised into three groups:

- Up to 1 MW_e inclusive, plants – minimum purchase prices, or possibly fixed prices are applied to these plants;
- Plants from 1 MW_e to 5 MW_e inclusive – the operators may apply either minimum purchase prices or fixed premiums to the market price;
- Over 5 MW_e plants – support in the form of fixed premiums.

As in the case of electricity generation from renewable sources, electricity generation from cogeneration also causes distribution companies to incur extra costs, which are reflected in the prices to final customers in the form of a contribution for covering the extra costs related to cogeneration. The contribution is uniform throughout the country.

The profit/loss from this activity is verified and adjusted every year, and reflected in regulated prices in the following regulated year, taking into account the time value of money.

5.7 Electricity supplies to protected customers

The electricity supply price to protected customers, in CZK/MWh, is composed of the following:

- the charge for system services,
- the charge for electricity transmission,
- the distribution charge containing the contribution for distributed generation and the distribution system operator's charge for facilitating payments,
- charge related to the contribution to cover the extra costs incurred in the mandatory purchase of electricity from renewable sources and cogeneration,
- a fixed charge, uniform throughout the country, for OTE's clearing activity, related to final customers' demand,
- the charge for electricity trading for protected customers, containing also a profit margin on the activity of electricity supply to protected customers,
- the energy purchase price set by the Office individually for each of the licence holders.

In the calculation of the rates for protected customers in the past, the energy purchase price was always applied as an average price set individually for the various regional distribution system operators on the basis of valuing protected customers' load profiles.

In price setting for protected customers for 2005, the average prices of energy have been allocated to the variable components in the high tariff rate, VT, and the low tariff rate, NT, taking into account the nature of the demand. Added to the resulting energy prices are the distribution prices (broken down to the standing charge and the variable component, or, as applicable, the variable components in VT and NT) plus all the other above-mentioned components of the price. The shares taken by each of the components making up the electricity supply price to protected customers in 2005 can be seen in Chart 1.

Chart 1 – Shares taken by each of the components making up the electricity supply price to protected customers in 2005