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Description of the cost establishment and rate calculation method according to section 82 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011 for the transmission lines of Gas Connect Austria GmbH, TAG GmbH and BOG GmbH, upon which basis approval by the regulatory authority was granted

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I. Scope and basic principles of the method

This method applies to all entry and exit points as well as interconnection points of the transmission line(s) of the transmission system operators (TSOs) and includes the reasonable costs of the following transmission systems according to Annex 2 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011:

- Hungaria-Austria pipeline (HAG)
- Penta West pipeline (PW)
- Süd-Ost pipeline (SOL)
- Kittsee-Petrzalka pipeline (KIP)
- Primary distribution system (PVS 1)
- Trans-Austria pipeline (TAG)
- West-Austria pipeline (WAG)

If Annex 2 of the Natural Gas Act 2011 is amended during the four-year regulatory period, the costs may be recalculated ahead of schedule; such newly calculated costs then form the basis of an ordinance by the Regulation Commission of Energie-Control Austria.

As future developments can only be estimated, the regulatory authority reviews the calculation every four years and adjusts it to reflect actual developments.

II. Cost-reflective calculation approach

The method takes account of the reasonable costs of operation, (combustion) energy, maintenance, development of transmission lines, administration and marketing of capacities, the reasonable costs directly related to the installation and operation of metering equipment, including calibration and meter reading, and the prorated costs for the market area manager. These costs must be transparent and correspond to those of an efficient and structurally comparable system operator, and they include an appropriate rate of return.

In accordance with section 82 para. 3 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, the costs calculated by the TSOs by applying the method are to be presented and proved to the regulatory authority by providing all data used in the calculation.

The costs calculated with this method take into account any surplus or deficit between 2007 and 2011 based on the examination by the regulatory authority.

III. Cost elements

III.1. *Investments, reinvestments and depreciation*

The method takes account of the capacity investments planned for the next four years which are covered by the approved coordinated network development plan.

After four years, the regulatory authority checks for deviations between planned investments and investments that were actually carried out in the previous period. Any such deviations in terms of capital costs are revised and taken into consideration when recalculating the costs. Concerning the related adjustment, point III.11 applies.

The base values for investments and depreciations are determined as follows:

To reflect debt, the book value of the assets declared in the balance sheet is used, multiplied by the debt ratio and remunerated applying the nominal cost of debt.

$$DebtAssets = CostofDebt \times \sum_{a=1}^{k} (BV_a \times DebtRatio)$$

BV_a: book values of individual assets

To take account of depreciation of the debt-financed assets, the debt-financed book values are divided by the standardised remaining useful life; depending on the TSO, the depreciation period is 20 to 30 years for natural gas pipeline systems according to section 7 para. 1 item 15 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011 and 12 to 17 years for compressor stations and other assets:

$$DebtDepr. = \sum_{a=1}^{k} \left(\frac{BV_a \times DebtRatio}{\left| s\tan d.UL_a - (2013 - yearofcommissioning_a) \right|} \right)$$

As for new investments in natural gas pipeline systems according to section 7 para. 1 item 15 Natural Gas Act 2011, the depreciation period is 20 to 30 years based on nominal historical costs and 12 to 17 years for compressor stations and other assets; the exact periods differ between the TSOs.

For the equity-financed share, adjusted replacement values are calculated and remunerated applying the real cost of equity. In order to calculate the replacement values as of 1 January 2013, the imputed depreciation periods of the tariff period 2007-2012 of 50 years for natural gas pipeline systems according to section 7 para. 1 item 15 Natural Gas Act 2011 and of 30 years for compressor stations and other assets are applied:

$$EquityAssets = CostofEquity_{real} \sum_{a=1}^{k} \begin{cases} HC_a * \frac{stand.UL_a - (2013 - yearofcommissioning_a)}{stand.UL_a} * EquityRatio * (1+i)^{(2013 - yearofcommissioning_a)}; & if \ (stand.UL_a - (2013 - yearofcommissioning_a)) \geq 0 \\ 0; \ if \ (stand.UL_a - (2013 - yearofcommissioning_a)) < 0 \end{cases}$$

The imputed depreciation for the equity part as from 2013 is calculated by adding up the adjusted residual replacement values (calculated with a constant annual appreciation factor “i” ranging between 4.17% and 4.54%, depending on the TSO) and dividing them by a weighted remaining useful life. For weighting, the percentage of each asset's replacement value in relation to the total replacement values, grouped into the assets originally imputed to be written off over 50 or 30 years, is calculated. This percentage is multiplied by the standardised remaining useful life of the individual asset. This results in the weighted remaining useful life.

$$EquityDepr. = \sum_{a=1}^{k} \begin{cases} \frac{HC_a * \frac{stand.UL_a - (2013 - yearofcommissioning_a)}{stand.UL_a} * EquityRatio * (1+i)^{(2013 - yearofcommissioning_a)}}{weightedRUL}; & if \ (stand.UL_a - (2013 - yearofcommissioning_a)) \geq 0 \\ 0; \ if \ (stand.UL_a - (2013 - yearofcommissioning_a)) < 0 \end{cases}$$

For the calculation of investment costs after 1 January 2013, the imputed depreciation period (standardised useful life) is, depending on the TSO, 20 to 30 years for natural gas pipeline systems according to section 7 para. 1 item 15 Natural Gas Act 2011 and 12 to 15 years for the remaining assets.

III.2. Capital structure / cost of capital

According to section 82 para. 1 in conjunction with section 80 para. 3 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, the reasonable rate of return for calculating the cost of capital is derived from the weighted average cost of capital (WACC) for a normal capital structure and the income tax burden. A ratio of 40 to 60 between equity and debt is considered a normal capital structure.

The normal capital structure must reflect overall industry aspects as well as significant factors of individual companies which undercut the equity or debt capital shares by more than 10%. The capital structure applied is derived from the book values and must be substantiated by the company. The values are reviewed by the regulatory authority.

III.3. WACC

As the principles of network regulation are similar for distribution system operators (DSOs) and TSOs, the WACC calculation approach for the former is applicable to the latter as well. However, cost of debt and cost of equity have to be handled separately because contrary to DSOs, for TSOs replacement values are applied for the equity-financed assets.

As a first step, the applicable cost of debt is determined:

Cost of debt	
Risk-free rate	**3.270%**
Risk premium for debt capital	1.45%
Cost of debt (pre-tax)	**4.720%**

Given the decision to use replacement values for equity-financed assets, a real interest rate for equity is used to calculate remuneration.

The Fisher equation applies:

$$(1+i_{nominal}) = (1+i_{real}) * (1+InflationRate)$$

The following correlation can be derived:

$$i_{real} = \frac{(1+i_{nominal})}{(1+InflationRate)} - 1$$

As a compensation for the marketing risk in regard to unsold line capacity, a risk premium of 3.5% on the cost of equity is used.

The following interest rate for equity-financed assets results:

Cost of equity	
Nominal risk-free rate	**3.270%**
Inflation rate	**2.251%**
Market risk premium	**5.0%**
Ungeared beta	**0.325**
Geared beta with a 40% equity ratio	0.691
Real cost of equity (post-tax)	4.374%
Real cost of equity (pre-tax)	5.832%
Capacity risk premium	3.500%
Real cost of equity (pre-tax), incl. capacity risk premium	**9.332%**

III.4. Operating costs

Operating costs are not individually calculated for each transmission line but for the entire transmission system (according to Annex 2 *Gaswirtschaftsgesetz* [Natural Gas Act] 2011) of a TSO, without depreciation. The reasonable, verified operating costs of the previous four years are adjusted up to the time of calculation with 2.251%[1] p.a. and subsequently, their average is determined. This adjustment accounts for exogenous factors, i.e. those beyond the company's control. The factors which can be controlled by a company are represented by an average productivity offset amounting to 2.5% p.a.

The reasonable costs incurred in implementing the third package are allowed without normalisation unless they are one-time implementation costs. Proof of these costs must be provided to the regulatory authority.

Given the incentive regulation approach, deviations of actual from forecast operating costs are not revised.

[1] Five-year average of the inflation rate change (as of April 2012).

III.5. Individual risk premium

Apart from a general compensation of capacity risk as part of the cost of equity, additional individual risk premiums apply based on the calculated capacity risk.

III.6. Energy costs

Energy costs are listed separately from other operating costs, without applying the productivity offset, and are included in the allowed costs after four years at their actual values.
If the actual energy costs considerably exceed the forecast figures, a corresponding increase of the applicable rates is to be considered upon the system operator’s request.
Procurement of the energy needed for compression must be non-discriminatory and transparent.

III.7. Flow commitments

In accordance with the *Gas-Marktmodell-Verordnung* (Gas Market Model Ordinance) 2012, flow commitments must be procured through non-discriminatory and transparent procedures under appropriate conditions. The related reasonable costs are included in the allowed costs and examined closely so as not to create negative incentives. Flow commitments related to oversubscription are considered in the allowed cost and review only to the extent they were compensated for (10%).

III.8. Costs of the market area manager and of regulation

In accordance with section 74 para. 1 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, the method includes prorated reasonable costs of the market area manager without applying the productivity offset. The cost of regulation is included in the prorated market area manager costs assigned to each TSO according to section 32 para. 1 *Energie-Control-Gesetz* (E-Control Act).

III.9. Other revenues and income

Regulated companies must report on any revenues from additional transport-related services for system users which are collected based on rates or charges set by ordinance; the allowed costs are then reduced accordingly.

III.10. Revenues from auctions, excess capacity use, interruptible transport contracts and oversubscription

Surplus revenues from auctions (above the rates set by ordinance or the reserve price) as well as revenues from excess capacity use, interruptible transport contracts and oversubscription do not impact on the cost review. Surplus revenues from auctions are to be used as provisions available for capacity expansion measures undertaken while this method applies. The cost review includes verifying if and how these provisions were used. If they were indeed used, the costs allowed for the following period are not reduced. If the provisions were not used for capacity development, they either reduce costs in recalculation or are kept available for investment in later regulatory periods.

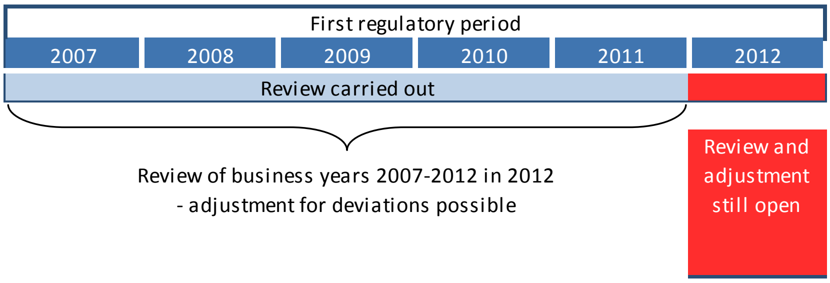
Revenues from marketed capacities which were not accounted for in the established volume situation are accounted for in the review carried out after four years following the same principles as above.

40% of the revenues from interruptible transport contracts and 90% of the net revenues from oversubscription mechanisms according to Regulation (EC) No 715/2009 remain with the TSO up to a total annual revenue amounting to 15% of the allowed costs. Revenues are reviewed by the regulatory authority. When reviewing the costs, point III.11 applies.

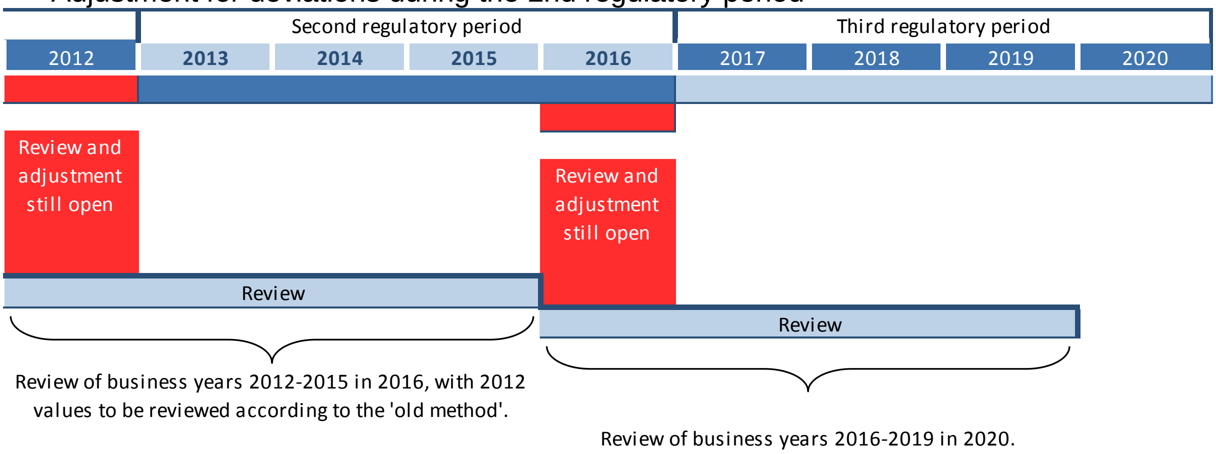
III.11. Adjustment for differences between forecast and actual figures

When recalculating costs (CAPEX and energy costs) after four years, it is necessary to account for deviations of actual figures from forecast ones. In the interest of comparability, the deviations of actual from forecast costs during each year are compounded to the first year of the next regulatory period.

As the last business year of a regulatory period is still ongoing when the review is carried out, the adjustment relating to that year can only be taken into account in the course of the review of the following regulatory period, as is shown in the figures below:



Adjustment for deviations during the 2nd regulatory period



The deviation (between actual and forecast CAPEX) of every year is compounded to the first year of the following regulatory period using the reasonable cost of debt.[2] This is to prevent that incentives for over- or underestimating the actual costs are created.

[2] $(1+i)^n$, where n stands for the number of years until the first year of the next regulatory period.

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IV. Volume situation

According to section 82 para. 2 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, the volume situation is established by comparing the contracted capacity as of 1 June 2012 with the maximum technical capacity.

When establishing the volume situation for the period 2013-2016, the imputed amount of existing contracted capacity from 2017 onwards is permanently fixed, leaving aside capacities which are not transferred to suppliers according to section 170 para. 7 Natural Gas Act 2011. If in the meantime, additional capacities (beyond the committed capacities determined here) are allocated at the individual entry/exit points, they are additionally taken into consideration. Any decline of committed capacities detected in the volume situation for the period 2013-2016 does not impact on the calculation of the volume situation for price control periods from 2017. This prevents the remaining consumers from having to absorb the decline in capacity demand in the transmission system. If this results in a shortfall of cost coverage for the transmission undertaking or the parent undertaking, such shortfall is not subject to an adjustment according to point III.11. Instead, the TSO carries the marketing risk, for which it is compensated by the risk premium included in the cost of equity and an individual risk premium.

V. Equalisation payments – section 70 para. 2 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011

If the rates and charges set are such that one TSO receives charges that should go to another, thereby creating an overhang for the former and a shortfall of costs for the latter, compensation is provided through interconnection point charges or monthly payments between them.

VI. Further elements

VI.1. Contract terms

The rates apply to contracts with a term of at least one year. The following factors are used to calculate the rates for shorter contracts:

Quarterly products:	factor 1.25
Monthly products:	factor 1.5
Daily products:	factor 1.75

VI.2. Firm transports

<u>Firm capacity types:</u>

- **Freely allocable capacity:** firm capacity that can be used in combination with any other points in the market area (incl. the virtual trading point [VTP]).
- **Dynamically allocable capacity:** capacity that functions as firm capacity in combination with specified entry/exit points; use in combination with other entry/exit points (or the VTP) is possible on an interruptible basis.

VI.3. Interruptible transports

The entry/exit rates applied are the same for firm and interruptible transports. In case of interruptions, an amount E_{Rm} is refunded to the transport customer for the duration of the interruption. Compensations (E_{Rm}) due during one service month take the form of reductions of the charge payable (E_m) for that service month.

The compensation (E_{Rm}) to be paid by the TSO is calculated as follows:

$$E_{Rm} = \left(\frac{E_m * rf}{h_m * q} \right) * \left(\sum_{R=1}^{h_R} q_{diffR} * h_R \right) \leq E_m$$

where:

E_{Rm} = the reduction of the monthly charge

E_m = the monthly charge

h_m = the total number of hours of the month during which the interruption occurs

q = the hourly capacity offered

h_R = the number of hours in the service month that were affected by the interruption

q_{diffR} = the difference between the hourly capacity offered and the actually available hourly capacity during each hour affected by the interruption

rf = the compensation factor, with $rf \geq 1$

In general, the ship-or-pay rule also applies to interruptible transports. This means that the TSO commits to reserve an hourly throughput for transport customers. In return, transport customers commit to pay for this reserved throughput even if they do not or not fully nominate it.

For entry points at which entry into the pipeline system is not physically possible (non-physical entry points), transport is offered on an interruptible basis.

There is no compensation in case of interruptible transports on the basis of booked dynamically allocable capacity according to VI.2.