METHODOLOGY PURSUANT TO SECTION 82* GASWIRTSCHAFTSGESETZ *(NATURAL GAS ACT, GWG) 2011 FOR TRANSMISSION SYSTEMS OF Austrian Gas Transmission System Operators (TSO's)

The methodology will be published on the company website upon approval.

CONTENTS

I Scope

The present document outlines the methodology applicable for establishing the costs and specifying the framework for setting charges by Austrian Gas TSOs. This includes all entry and exit points and interconnection points on the transmission line(s) of the transmission system operator (TSO). Specifically, the present methodology covers the reasonable costs of the transmission systems according to Annex 2 *Gaswirtschaftsgesetz* (Natural Gas Act) 2011.

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. Similarly, modifications of the European Tariff Network Code currently under discussion could require the level of charges to be redefined.

II Reasonable grid costs

The methodology provides for a reasonable return on the capital tied up in the company (i.e. the regulated asset base) and covers reasonable depreciation, operating costs and the prorated costs of the market area manager and of regulation. These costs must be transparent and correspond to those of an efficient system operator with a comparable structure.

In accordance with section 82 para. 3 *Gaswirtschaftsgesetz* 2011, the TSO applies the methodology, calculates the costs, and provides all data used in the calculation to the regulatory authority to prove how the calculation was done.

The costs calculated with this methodology take into account any surplus or deficit between 2012 and 2015 according to the framework that was in place for the first and second regulatory periods.

II.1. *Regulated asset base (RAB) and depreciation*

The regulated asset base (RAB) includes both existing long-term assets, as recorded in the annual financial statements, and future investments, planned for the purpose of expanding capacity or maintaining the existing system (reinvestments).

The base values for RAB and depreciation of existing assets have been specified and are summarised in procedures V MET G XX/12 (old investments) for 2011. These assets continue to be included in accordance with the then-applicable rules and are written off uniformly over their remaining useful life.

As in the second regulatory period, depreciation of any and all new pipeline investments in the existing grid is calculated on the basis of nominal historical costs and with a useful life of 30 years,. The useful life for compressor stations and other assets continues to be 12 years. (In the case of assets of former BOG, investments between 2013 and 2016 are assumed to have a useful life of 20 or 15 years.)

The previous methodology generally distinguished between equity-financed and debt-financed grid assets. Nominal values were used for the latter, adjusted replacement values for the former. This distinction continues to apply in the present methodology for existing and new assets.

A uniform total RAB is determined for the third regulatory period based on the pre-existing assets, the investments made in the second regulatory period, and the investments planned for the third period. Setting an average RAB value for the entire period during which the methodology applies should keep the adjustments that need to be made for investments to a minimum.

Debt-financed grid assets

As in the second regulatory period, depreciation of the debt-financed portion of the existing RAB is calculated by dividing the book values of the debt-financed assets by the standardised remaining useful life. Accordingly, the existing assets' book values are reduced annually by this depreciation. All new investments made during a year are included on one joint line and are handled in the same way.

Equity-financed grid assets

In the second regulatory period, adjusted replacement values were determined for the equity-financed share of assets. Changes in book values and depreciation of assets were accounted for through an appreciation factor of between 4.14% and 4.54%.

This factor enables projecting the values forward to the end of the 2016 business year. For the period afterwards, the factor is updated to take current trends into account. In this, the published appreciation factors applied by the German gas grid charges ordinance (GasNEV[1]) serve as a point of reference. The resulting appreciation factors between 0,13 % - 0,46 % per year take into account the differing composition of fixed assets in the different transmission systems and are based on the developments witnessed over the past four years. This kind of reference period ensures that overall trends in the cost development of assets are captured. The logic that a regulatory period makes reference to the preceding regulatory period for this purpose and with this intent will also be applied in future.

Aside from this consideration, equity-financed assets are treated in the same way as debt-financed assets.

II.2. *Capital structure*

According to section 82(1) in conjunction with section 80(3) *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, 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 respect general factors that manifest across sectors. If a company falls short of the equity ratio corresponding to the normal capital structure by more than 10% (relative to equity and not total capital), the company's actual financing structure will be used in calculations for the next regulatory period instead of the normal capital structure. In case of extraordinary developments which impact the capital structure without long-term and long-lasting negative effects on the equity ratio, an average over the current period may be used when verifying whether the company is in line with the normal capital structure.

The company must demonstrably use the book values to calculate its capital structure. The regulatory authority verifies the annual values in the context of adjusting the CAPEX for the next regulatory period.

Verification of the capital structure is conducted as follows (based on the book values shown in the annual financial statements):

[1] http://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/Beschlusskammer9/BK9_91_Hinweise_und_Leitfaeden/Preisindizes/BK9_Hinweise_und_Leitfaeden_Preisindizes_basepage.html

+ intangible assets

+ tangible assets

– consumer contributions to construction costs

+/– any necessary adjustments

Regulatory asset base

– interest-bearing debt (reserves for pensions, loans, bonds)

Equity-financed assets

Equity ratio = Equity-financed assets / RAB

II.3. *Weighted average cost of capital (WACC)*

The rules previously used for calculating the weighted average cost of capital (WACC) continue to apply, but the individual values are adjusted to reflect interest rate developments on the capital markets.

First, the cost of debt is calculated:

Cost of debt	
Risk-free rate	**1.87%**
Risk premium for debt	0.83%
Cost of debt (pre-tax)	**2.70%**

For the cost of equity, a real interest rate is used to reflect the decision to use replacement values for equity-financed assets. The Fisher equation applies:

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

The following correlation can be derived:

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

A risk premium of 3.5% on the cost of equity applies as partial compensation for the marketing risk that results because the capacity amounts that were fixed in the method for the second regulatory period are used to project the minimum volume for future regulatory periods. For details on how the marketing risk is calculated, please refer to chapter III.2.

After adjusting for the evolution of interest rates on the capital markets, the following interest rate for equity-financed assets results:

Cost of equity

Nominal risk-free rate	1.87%
Inflation rate	2.06%
Real risk-fee rate	**-0.19%**
Market risk premium	**5.00%**
Ungeared beta	**0.40%**
Geared beta with a 40% equity ratio	**0.85%**
Real cost of equity (post-tax)	4.06%
Real cost of equity (pre-tax)	5.42%
Capacity risk premium	3.50%
Real cost of equity (pre-tax), incl. capacity risk premium	**8.92%**

II.4. *Mark-up for future investments*

In order to create an incentive for future investments, a mark-up on the real cost of equity to the amount of 0.8 percentage points applies for investments made from 1 January 2017. This mark-up is maintained only for the term of the third regulatory period, i.e. 2017-2020.

II.5. *Operating costs*

Influenceable operating costs (excluding costs for energy, CO2 emissions, the market area manager and regulation as well as other non-influenceable costs still to be determined) are not individually calculated for each transmission line but for the entire transmission system (as specified in Annex 2 *Gaswirtschaftsgesetz* (Natural Gas Act)) of the TSO. Under the previous methodology, this was done by projecting the reasonable, verified operating costs of the last four years to the time of tariff review and then the average was calculated.

Numerous restructuring measures have significantly affected historical values, which is why under the present methodology, the reasonable operating costs are instead based on the detailed numbers from the most recent annual financial statements that are available. After the regulatory authority has verified the reasonable costs, they are normalised and a number of adjustments are made in order to obtain a stable, comparable cost basis for the entire period. During this step, historical data (from earlier annual financial statements) are taken into consideration.

The costs are then projected forward to the first year in which the methodology applies and subjected to a cost path. The previous method used an average productivity factor of 2.5% p.a..

To determine the new productivity factor, reference is made to the results of an international gas TSO benchmarking exercise that took place in 2015-2016. Considering a median efficiency score of 82% and a target attainment period of 8 years (i.e. two regulatory periods) for realising efficiency gains, a revised productivity factor of 2.45% p.a. results.

At the same time, a factor to compensate for inflation (network operator price index or NPI) applies for the duration of the methodology. This factor is determined by weighting the consumer price index (CPI) and the index of collectively agreed wages and salaries (WSI) at 50% each. These two factors are used to determine the annual operating costs for each year in which the methodology applies and the average is used in the cost review. Based on 2012-2015 data, the NPI for the third regulatory period is 1.94%.

Given the incentive regulation approach, there is no ex-post adjustment for the influenceable operating costs.

The TSO's non-influenceable operating costs are not subject to a productivity factor. After four years the regulatory authority checks for deviations between planned non-influenceable costs and those that actually accrued. Any such deviations in terms of non-influenceable costs are taken into consideration according to chapter II.14.

II.6. *Individual risk premium*

The calculated overall risk is compensated by the general risk premium of 3.5% on the one hand and by an individual risk premium on the other. Please refer to chapter III.2 for more information. The individual risk premium set for the second regulatory period continues to apply for existing capacities until the end of the average useful life of the asset base that was determined in the methodology for the second regulatory period.

For new investments which lead to a capacity increase, a new risk calculation is done and the if a risk is identified it is compensated for.

II.7. *Energy and CO2 certificates costs*

Energy and CO2 certificate costs are handled separately from other operating costs, without applying the productivity offset: after four years, an adjustment for the actually incurred costs takes place. Energy costs comprise fuel gas, electricity, electricity grid utilisation charges, grid losses and metering discrepancies (unaccounted-for gas).

If the actual energy and CO2 certificates costs considerably exceed the forecast figures, the system operator can ask that a corresponding increase of the applicable rates be considered.

Procurement of the energy (gas and/or electricity) needed for compression must be non-discriminatory and transparent and is subject to an adequacy check by the regulatory authority. The energy costs for electrical compressors must be itemised into energy costs and grid utilisation charges for each grid level.

II.8. *Costs of the market area manager and of regulation*

In accordance with section 74(1) *Gaswirtschaftsgesetz* (Natural Gas Act) 2011, the present methodology 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(1) *Energie-Control-Gesetz* (E-Control Act). Both these elements are included based on forecast figures and are then revised once actual values are known.

II.9. *Other revenues and income*

Regulated companies must report any revenues they bring in from additional transport-related services for system users which are based on rates or charges set by ordinance; the allowed costs are then reduced accordingly. For revenues outside the regulated area (e.g.: cross-billing between transmission system operators for services rendered, management of balance groups) that are not deducted from the allowed costs in accordance with this provision, companies must provide proof that the corresponding costs are not allocated to the regulated area either. If such proof is not provided, the allowed costs will be reduced accordingly.

II.10. *System admission charge and system provision charge*

The system admission charge compensates the transmission system operator for all reasonable cost, considering normal market prices, directly arising from connecting a facility to a transmission system for the first time or altering a connection to account for a system user's increased connection capacity. The system admission charge is a one-off payment; system users must be informed of how it is made up in a transparent and understandable manner. In cases where connection costs are borne by system users themselves, the system admission charge is reduced accordingly. The system admission charge must be cost-reflective.

The system provision charge, payable by system users at the time of first connection or increase of contracted maximum capacity as a one-off payment reflective of capacity, covers the past and future network development measures necessary to enable such connection. It reflects the agreed extent of system utilisation. It is billed for at the time of signature of a system access contract or increase of the contracted maximum capacity.

If the contracted maximum capacity is contractually reduced for a continuous period of at least three years or if the system user has been disconnected for three years, s/he has a period of 15 years from payment to request that the system provision charge paid be reimbursed in proportion to the utilisation reduction.

The book value of the contributions for construction costs earned by the transmission system operator reduces the RAB and the depreciation amount reduces its cost.

II.11. *Excess revenues, excess proceeds from auctions, net revenues from capacity surrenders, revenues from day-ahead and long-term UIOLI*

The cost review does not include any corrections for general revenues in excess of what has been planned, surplus proceeds from auctions (above the rate set by ordinance or above the reserve price), net revenues[2] from surrender of contracted capacity and revenues from application of the day-ahead UIOLI (Use It Or Lose It) and long-term UIOLI mechanisms. These amounts can instead be used for investments in capacity expansion or for reinvestments (maintaining the existing system) that are carried out while this method applies. The cost review includes verifying if and how the proceeds were used. If they were indeed used, the costs allowed for the following period are not reduced. If they were not used for the above purposes, they either reduce the allowed costs for the next period or are earmarked for investment in later regulatory periods. In the latter case, the excess proceeds permanently reduce the RAB, starting with the following regulatory period.

Revenues from marketed capacities which exceed the planned revenues are accounted for in the review after four years according to the same principles as above. 25% of the revenues from interruptible transport contracts remain with the transmission system operator, i.e. are not part of the cost review.

The adjustments that result from the above are applied over a reasonable period of time (see II.15).

[2] The net revenue is the difference between the refund for the surrendered capacity under the existing capacity contract and any higher proceeds the transmission system operator receives from remarketing the surrendered capacity, including any auction surcharges.

II.12. *Incentives for oversubscription and buy back*

An oversubscription and buy-back scheme rests on an incentive regime reflective of the risks that offering additional capacity entails for the transmission system operator. In this context, additional capacity is defined as the firm capacity offered in addition to an interconnection point's technical capacity.

The structure of the oversubscription and buy-back scheme and the associated incentive regime are subject to approval by the regulatory authority in accordance with point 2.2.2. of Annex I to Regulation (EC) No 715/2009. In return for creating the scheme and assuming the related risks, up to 90% of the resulting revenues remain with the TSO.

II.13. *Additional incentives for TSOs*

The regulatory authority and the system operator agree on a set of positive effects on system service quality during the first year of the regulatory period. A variable incentive for achieving these effects is granted already as part of the current period, and the TSO must provide proof that the positive effects are present and reliable as part of the review process for the present methodology. The maximum incentive achievable is 5% of the TSO's operating costs (reduced for the non-influenceable costs). If the target is not achieved or only partially achieved, the differences are adjusted for. This incentive component is not included in the operating costs but is considered separately without any mark-up or mark-down. The methodology for proving the positive service quality effects and the associated incentive are subject to approval by the regulatory authority.

II.14. *Incentives cap*

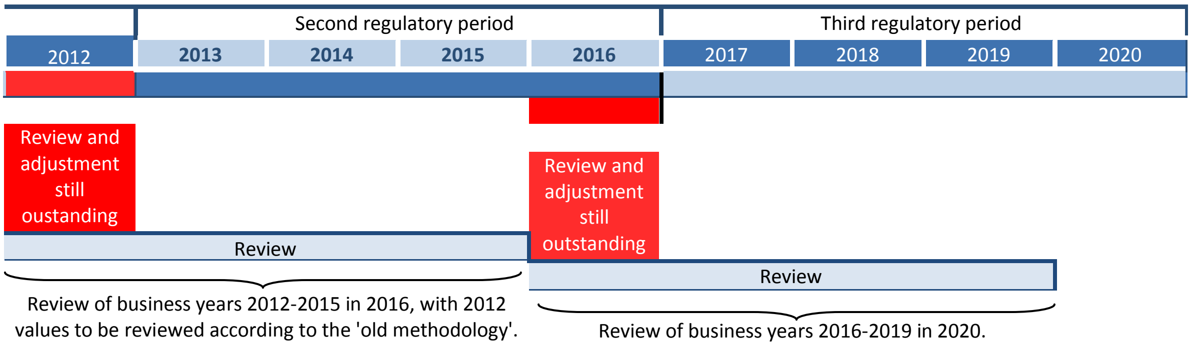
The cumulative amount of all incentives (II.11, II.12 and II.13) is capped at 25% of the return on equity determined. This refers to the interest on equity including the risk premium of 3.5% points.

II.15. *Adjustment for differences between forecast and actual figures*

When recalculating costs (CAPEX, non-influenceable operating costs, energy costs, CO_2 costs, costs of the market area manager and of regulation) and revenues after four years, it is necessary to account for deviations of actual figures from forecast ones.

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. This is shown in the figures below:

Adjustment for the second regulatory period



The CAPEX deviation of every year is compounded to the first year of the following regulatory period using the reasonable cost of debt.[3] This is to prevent that incentives for over- or underestimating the actual costs are created.

The adjustments are made with a view to a stable development of tariffs. If adjustments are made for more than one regulatory period, the rate used for compounding is the cost of debt applicable in the relevant period.

III Volume

III.1. *Establishing the relevant volume*

Regarding the relevant volume, the method for the second regulatory period provides as follows:

> *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*

[3] $(1+i)^n$, where n stands for the number of years until the first year of the next regulatory period

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 company or the parent company, such shortfall is not subject to an adjustment according to clause 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.

It can therefore be concluded that the relevant volume for the next regulatory period will be at least the same as that established according to the old methodology. The decisions in procedures V MET G XX/12 also hold for the present methodology. In addition, the following provisions apply:

Previously, capacities sold on a short-term basis were not included in the relevant volume. To make sure that customers now immediately benefit from these, the re-calculation of the relevant volume takes into account additional stable (short term) bookings at individual points. However, these volumes are not included in the risk-bearing volume. The additional short-term bookings taken into account correspond to the average over the previous regulatory period (2013-2015), and any deviations of the actual bookings from these averages are adjusted for in accordance with section II.15.

III.2. *Volume risk*

The original risk calculation took into consideration potential revenue shortfalls resulting from expiry of existing contracts until the end of the remaining useful life of the existing assets. This risk was determined for each of the company's relevant pipelines separately and then added up to determine a total risk. This was compensated for by way of the risk premium described above (+3.5 percentage points on the cost of equity and an individual risk premium).

Recalculating the risk is only possible for points where volumes are increased permanently. This is the case where:

- new capacity is created at a new point; or
- an existing point’s capacity is significantly increased.

The calculation method described above continues to apply.

If the newly added capacity permanently shifts bookings from one point to another, this effect must be taken into consideration when calculating the risk for both affected points.

The following principles apply for calculating deviations from the projected revenues:

- The manifested risk relates to the whole company and is calculated individually for each entry/exit point. Therefore, the TSO's risk manifests if the total revenues from bookings do not at least correspond to the revenues that would result from the projected volume.
- Annual capacities from expired contracts and unsold annual capacities that were projected to be sold can be replaced with short-term products but multipliers for products shorter than one year do not apply.
- Changes in the pipeline systems may cause capacities to be transferred to other or new points in the system and therefore potentially to other TSOs. Where this is the case, the receiving point/TSO must compensate the original point/TSO for the corresponding foregone revenue.

TSOs must ring-fence 50% of their risk premiums (3.5% risk premium on the return on equity and individual risk premium) and reserve them for actual future capacity risk. These reserves may not be distributed to shareholders and thereby reduced. Otherwise, materialising capacity risks could put the company's financial stability in jeopardy. In calculating the capital structure (s. chapter II.2), the ring-fenced premiums count towards equity, i.e. they raise the company's equity ratio. As long as the target capital structure is met, other parts of the company's equity may be distributed to shareholders on a continuous basis without triggering any negative effects on the allowed cost of capital.

IV Treatment of new or incremental capacity from planned investment projects

The costs planned for new or incremental capacity and the projected volumes must be itemised for each project separately. Incremental capacity is defined as an increase in existing technical capacity. New capacity is defined as the establishment of a new direction of flow (physical reverse flow) at an existing cross-border interconnection point or the creation of a new cross-border interconnection point.

Unless otherwise decided by the regulatory authority, the revenues expected from the projected new or incremental volume must be such that they cover the respective project's costs. The costs are determined by official decision.

The costs of planned investment projects are determined in accordance with chapter II.2 of this methodology. If additional capacity resulting from the realisation of planned investment projects competes with existing capacity, the existing capacity's potential losses in profit margin count as costs, to be taken into account in addition to the costs calculated according to chapter II.2. Planned OPEX are compared with actual OPEX at the end of the regulatory period during which they first arise, and any necessary adjustments are made. From then on, the actual OPEX become part of the total OPEX in accordance with the methodology then in force. The projected volume is included in the calculation on the basis of planned values. If the project is realised, volumes are determined in future as described in chapter III.

The logic described in chapter III.2 applies when calculating the investment projects' volume risk.

V Equalisation payments – section 70(2) Natural Gas Act 2011

If the rates and charges set are such that one TSO receives charges that should go to another, corresponding monthly payments between the TSOs are made to correct the situation.