Methodology pursuant to section 82 Gas Act 2011

for the fifth period for transmission systems of xy GmbH

CONTENTS

I. Scope

The present document outlines the methodology applicable for establishing the costs and specifying the framework for setting charges by XXX GmbH for the fifth period, i.e. from 1 January 2025 until 31 December 2027. This includes all entry and exit points on the transmission line(s) of the transmission system operator (TSO). Specifically, the present methodology covers the reasonable costs of the following transmission systems according to Annex 2 Gas Act 2011:

- *xyz*

If Annex 2 of the Gas Act 2011 is amended during the period, the costs may be recalculated ahead of schedule.

The below methodology serves to determine the costs and the transported quantity, to be recovered through the capacity part of the network charges and the commodity part of the network charges.

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, (controllable and non-controllable) operating costs and the prorated costs of the market area manager and of regulation. These costs must be transparent, take into account the need for system integrity and its improvement and reflect the actual costs incurred, insofar as they correspond to those of an efficient and structurally comparable network operator. This also includes future investments that are allowed in principle.

In accordance with section 82(3) Gas Act 2011, the TSO must first calculate its costs by applying the present methodology and then present these results as well as proof of all underlying cost and calculation data to the regulatory authority.

The methodology includes a reconciliation of any over- or under-recovery from the previous periods.

1. Regulated asset base and depreciation

1.1. Regulated asset base

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

Nominal values from the annual financial statements (book values) apply throughout.

During the third and fourth regulatory periods, companies could choose whether to have any excess revenues reconciled through the RAB or the regulatory account. If they chose the former option, the RAB is reduced by any such excess revenues.

For the fifth period, both legacy assets and planned investments feed into an overall annual RAB. Setting the right annual RAB will minimise retroactive CAPEX adjustments. It is recalculated annually with a t-3 time lag (s. chapter 14.3). Assets are divided into legacy assets (acquired up to 2024) and new assets (acquired from 2025 onwards), and different WACCs apply to these two asset categories (s. chapter 4).

1.2. Depreciation

Depreciation is calculated using the values from the annual financial statement.

2. Transition from replacement values to book values for equity-financed assets

During previous regulatory periods, depreciation of equity-financed assets (acquired up to 2020) was calculated by applying replacement values and real interest rates. The new regulatory regime for TSOs is more similar to the DSO regime, including both a regulatory account for reconciling any over- and under-recovery and use of book values for CAPEX.

In order to avoid a sharp break, cost increases from the transition are accounted for, during the fifth regulatory period only. These additional allowed costs apply for three years, i.e. end in 2027. The change is thus softened for the fifth regulatory period and will only come to fully bear during the sixth period.

The additional component of the allowed cost is calculated from

- CAPEX as per the previous calculation method; and
- CAPEX as per the new calculation method,

for 2022 (which is the most recent available value), applying future interest rates (s. chapter 4) and an inflation rate of 2.5%[1] for calculating the real interest rate.

In the interest of a gradual evolution of the system charges during the regulatory period, half of the above difference is allowed in 2025, 2026 and 2027 (i.e. overall, 150% of the difference calculated for 2022 is allowed during the entire period).

3. Capital structure

According to section 82(1) in conjunction with section 80(3) Gas Act 2011, the cost of capital is derived from the weighted average cost of capital (WACC) for a normal capital structure and the applicable income tax rate. A normal capital structure is considered to consist of 40% equity and 60% debt.

[1] This is the average of the EUR Inflation Swap Zero Coupon Ex Tobacco 5Y on 31 January 2024 (1.9938%) and the OeNB inflation forecast for 2025 (3.0%) as of 31 January 2024.

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), section 80(3) Gas Act 2011 stipulates that the company's actual capital structure and its actual equity and debt shares be used to calculate the WACC. By contrast, a higher equity ratio does not change the WACC calculation; a normal capital structure would still be assumed.

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 regulatory period to be reviewed 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 annual historical values are verified in the context of calculating the CAPEX for the next period.

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

+ intangible assets
+ tangible assets
- customer 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

4. Weighted average cost of capital (WACC)

As during previous regulatory periods, a WACC approach applies.

Due to the volatility of interest rates currently observed on the capital markets that are the result of the exceptional inflationary developments triggered by Russia's war of aggression against Ukraine since February 2022, the authority is introducing a new approach by setting two different WACCs for the first time. As was done for the gas DSOs, there is a distinction between a WACC for legacy assets (acquired up to 31 December 2024) and a WACC for new investments (acquired thereafter).

More precisely, the fifth regulatory period features a $WACC_{legacy\ RAB}$ that is multiplied by the cost of capital for the RAB acquired up to the end of 2024, and a $WACC_{new\ investments}$ that is multiplied by the RAB that is acquired from 2025 onwards. The $WACC_{legacy\ RAB}$ has the same value during the entire three-year regulatory period, while the $WACC_{new\ investments}$ is re-calculated every year and applied to the investments made during each individual year until the end of the regulatory period.

When setting the WACC for new investments, the most recent available yield numbers are used as they best reflect the current developments on the financial markets.[2] The WACC for new investments will be updated annually and applied it to the cost of debt and the risk-free rate for the cost of equity. The market risk premium and the beta factor remain unchanged.

The cost of debt and the risk-free rate for the cost of equity for investments in 2025, which applies for the entire fifth regulatory period, is based on data from 1 February 2023 to 31 January 2024 (i.e. a twelve-month average). Starting in 2025, the $WACC_{new\ investments}$ for the following year will be calculated annually, based on a 12-month average, always with a cut-off date of 31 January.

The figure below illustrates the composition of both WACCs for the fifth regulatory period and a comparison with the WACC that applied during the fourth regulatory period.

[2] The $WACC_{new\ investments}$ applies to all new investments, i.e. including both replacements and expansions. There is no need to further differentiate.

		WACC for the fifth period of gas TSOs		
	previous period	$WACC_{legacy\ RAB}$	$WACC_{new\ investments2025}$	$WACC_{new\ investments2026-2027}$
risk-free cost of equity	1.08%	1.16%	3.08%	*updated annually*
cost of debt	1.41%	2.26%	3.99%	*updated annually*
cost of issuing debt	0.20%	0.20%	0.20%	0.20%
market risk premium	4.50%	5.00%	5.00%	5.00%
geared beta	0.400	0.410	0.410	0.400
ungeared beta	0.850	0.884	0.884	0.884
debt share	60.00%	60.00%	60.00%	60.00%
equity share	40.00%	40.00%	40.00%	40.00%
tax rate	25.00%	23.00%	23.00%	23.00%
cost of equity *pre-tax*	6.54%	7.25%	9.74%	*updated annually*
cost of equity *post-tax*	4.91%	5.58%	7.50%	*updated annually*
cost of debt *pre-tax*	1.61%	2.46%	4.19%	*updated annually*
WACC pre-tax	**3.58%**	**4.37%**	**6.41%**	*updated annually*
WACC **post-tax**	2.69%	3.37%	4.94%	*updated annually*

Figure 1: Components of the WACC in accordance with section 80 Gas Act 2011

5. Operating costs

The authority does not consider the operating costs for each transmission line separately. Instead, all of a TSO’s transmission lines are grouped together (in line with annex 2 Gas Act 2011). The controllable operating costs are audited based on the last available annual financial statements, including also data from preceding years. This can have a smoothing effect on the costs.

The controllable operative costs (i.e. excluding costs for energy, for CO2 certificates, prorated costs for the market area manager and for regulation in line with section 32(1) E-Control Act, as well as other non-controllable costs that might emerge) are brought forward to the first year during which the present method applies. To do this, the network operator price index (NPI) is used to account for inflation in 2023 and 2024 (i.e. from 1 January 2023 to 31 December 2024) and a general productivity growth rate of 0.4% p.a. is applied. This X-gen is taken from the regulatory regime for DSOs and the authority finds it to be appropriate because the activities of DSOs and TSOs are comparable.

In light of the above, the budgeted costs for the fifth regulatory period, i.e. from 1 January 2025 to 31 December 2027, will be marked up annually by applying the NPI and marked down annually by applying both a general productivity growth rate (X-gen) and an individual efficiency target (X-ind).

The mark-up is the NPI. While an NPI of 2.5% is used for planning, this value is updated with a T-3 time lag (s. chapter 14.3), using the NPI that actually manifested during the relevant period. As this means a change to the costs, it also implies changing the basis for calculating the values for the following years.

The mark-down includes both the general productivity growth rate (X-gen) as described above, and individual efficiency targets (X-ind). The latter ensure that companies actually improve their efficiency, as required in accordance with section 82(1) Gas Act 2011.

The Council of European Energy Regulators (CEER) is currently conducting an international efficiency benchmark of European gas transmission system operators. It is likely to be finalised during the fifth regulatory period. If the authority considers the data, results and conclusions from this benchmark to be adequate, they will be used to calculate X-ind (assuming a target attainment period of 7.5 years) and this X-ind will retroactively apply to the OPEX during the fifth regulatory period.

The total X-factor for the TSOs (i.e. X-gen and X-ind) is capped at 2.0% p.a.

New legal obligations that have come into place will likely mean additional costs for the companies that were not part of the most recent available OPEX figures (e.g. additional IT expenses triggered by legal stipulations on information security such as the NIS Directive, or by the EU Methane Emissions Regulation). These are translated by allowing a lump sum as part of the costs. After the regulatory period, this lump sum is compared to the costs that have actually been incurred and the difference is corrected for. Companies must provide proof of the actually incurred additional costs (e.g. for new staff that needed to be hired, or new (service) contracts that needed to be concluded).

The companies' non-controllable costs are not subject to a productivity factor. When the present method is next reviewed, the authority will verify whether there have been any deviations of actual from planned non-controllable costs and reconcile them as described in chapter II.15.

6. Individual risk premium

Given that the risk is borne by the customers (collectively), the individual risk premium is no longer needed from the fifth regulatory period onwards. For further details, please consult chapter III.2.

7. Energy and CO_2 certificates costs

Energy and CO_2 certificates costs are handled separately from the other OPEX. If expenses have proven efficient, they are allowed and passed through as they are each year. Energy costs comprise fuel gas, electricity, electricity grid utilisation charges, fees and costs set by regulations in force, grid losses and metering discrepancies. These costs form the basis for the flow-based charge.

If the actual expenses for energy and CO_2 certificates deviate from the planned values, this is reconciled by applying the method described in chapter 14.3, following a t-3 time lag. The costs planned for the next year are also updated each year and integrated into the allowed costs for the flow-based charge going forward, in line with chapter 14.4. Compression energy (gas and/or electricity) must be procured by way of non-discriminatory and transparent procedures; the authority will verify whether the relating process was adequate. Companies must itemise the energy costs for electrical compressors, differentiating between energy costs and system utilisation charges for the relevant grid level.

8. Costs of the market area manager and of regulation

The costs of the market area manager are taken into account 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) E-Control Act. Both values are allowed as planned and any deviations are then accounted for with a t-2 time lag as described in chapter 14.2.

9. Other revenues and income

Any income generated from unrelated transport services provided to system users must be itemised. It is then deducted from the allowed costs. If revenues from non-regulated activities (e.g. provision of services to other system operators, management of balance groups) are not deducted from the allowed costs, companies must provide proof that they are not allocated to the regulated area. If such proof is not provided, the allowed costs are reduced accordingly.

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; the system user 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 connection capacity and must be paid when the corresponding contract is signed.

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, they may request reimbursement of the system provision charge in proportion to the utilisation reduction. This must happen within a period of 15 years following the payment of the charge.

The book value of the contributions for construction costs earned by the transmission system operator reduces the RAB.

11. Revenues, excess revenues, revenues from multipliers, excess proceeds from auction surcharges, net revenues from capacity surrenders, revenues from interruptible capacity, and revenues from day-ahead and long-term UIOLI

The total actual revenues (actual rates x actual quantity) must be compared with the forecast revenues (actual rates x forecast quantity). Significant effects from tariffs setting (and thus, from established compensation payments) must also be taken into account as part of the review.

Next, the following items must be retroactively reconciliated: any over- or under-recovery (i.e. more quantity being transported than forecast leads to excess revenues, while multipliers can lead to a shortfall), revenues from interruptible capacity, and revenues from congestion management (i.e. net revenues[3] from returning contracted capacity, revenues from day-ahead UIOLI and long-term UIOLI from before the audited period).

Such over- or under-recovery is audited by 15 March of the following year, in line with chapters II.14 and 14.2, and is reconciled over a period of one or several years during the tariff period as laid down in Article 17 et sqq. TAR NC.

12. Incentives for oversubscription and buy back

The oversubscription and buy-back scheme incentivises TSOs to make available additional capacity, taking into account the technical conditions, such as calorific value, temperature and expected consumption, as well as the available capacity in adjacent networks. The TSOs apply a dynamic approach to recalculating the technical or additional capacity. The oversubscription and buy-back scheme is based on an incentive regime reflecting the risks TSOs incur by offering additional capacity. 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 regulatory approval, 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.

13. Additional incentives for TSOs: quality and performance criteria (bonus-malus system)

This chapter does not apply during the fifth regulatory period.

14. Reconciliation of deviations of actual expenses from planned expenses and updates in the course of the regulatory period

Several types of costs (CAPEX, non-controllable OPEX, NPI and X-ind with reference to the controllable OPEX, costs for energy, CO2, MAM and regulation pursuant to section 32(1)

[3] 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.

E-Control Act) and the revenues need to be retroactively checked and any differences between the actual and budgeted values need to be reconciled as quickly as possible.

14.1. Logging deviations (regulatory account)

The regulatory account (Article 17 et sqq. TAR NC) serves to record deviations in two separate areas:

- Quantity deviations:
  - Revenues from the flow-based charge
  - Compensation payments from the flow-based charge
  - Energy costs (electricity and gas) and system losses, losses of fuel gas, and metering discrepancies
  - CO_2 costs
- Capacity deviations:
  - All other items

The results of the calculations (i.e. the balance of the regulatory account) must be recorded as assets or liabilities in the annual financial statement of the company. The items are valued in line with the accounting rules in place.

Regardless of their being recorded in the financial statements, the differences are marked up or down from the allowed cost for the next tariff period(s).

14.2. Reconciliation with a two-year time lag (t-2)

The below data are available immediately after the tariff period and can thus be reconciled for the following year (t-2 time lag):

- Revenues from the capacity-based charge
- Revenues from the flow-based charge
- Auction revenues
- Revenues from interruptible tariffs
- Congestion management revenues
- Revenues from cross-border storage usage
- Cost of the market area manager and regulation
- Over-/under-recovery from set tariffs

- Compensation payments paid/received

14.3. Reconciliation with a three-year time lag (t-3)

Given that the necessary data are not available in the year after the tariff period, the below items can only be calculated one year later, and then be reconciled for the following year (t-3 time lag):

- CAPEX (depreciation and cost of capital, arising from differences between actual and planned book values)
- NPI and X-ind reconciliation relevant for controllable OPEX
- Energy costs
- CO_2 costs
- Other revenues
- Arbitration costs
- AGORA costs
- Innovation budget

14.4. Integration of new plan values

At the same time, the budget for the remainder of the regulatory period is adjusted each year, taking into consideration the following values:

- Transported quantity (capacity and commodity)
- Energy costs and CO2 costs
- Planned investments

14.5. Procedure

In 2025 and 2026, annual reconciliation will take place to account for any deviations from the fourth regulatory period (2021-2024) that have not yet been reconciled. Any deviations from previous regulatory periods that have already been calculated but not yet reconciled will continue to be treated in accordance with the legacy methodology.

As the last business year of a 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 period. This might even apply to the two business years that precede the end of the regulatory period.

Deviations of CAPEX are brought forward to the year of the reconciliation by annually applying the appropriate cost of debt for new investments. This is to prevent incentives for over- or underestimating the actual costs.

Annual reconciliation means that companies must submit the required data for the items listed in sections 14.2 and 14.4 by 10 January of the following year, and the data for the items listed in section 14.3 by 30 June of the following year.

III. Transported quantity

1. Calculating the relevant quantity

Given that the system users collectively bear the quantity risk, a risk premium is no longer necessary from the fifth regulatory period onwards.

Previously, the projected transported quantity was calculated based on the average past bookings. However, in light of the recently volatile usage of the gas grid and the rapid evolution witnessed over the last two years, this is no longer appropriate. Instead, the transported quantity is projected based on existing and expected bookings. This includes both annual contracts and capacity bookings for shorter periods of time. In order to be able to use the numbers for the next (gas) year, the corresponding data must be made available by the end of February.

The TSOs must do everything in their power to maintain existing long-term capacity contracts until the end of their contract term (pacta sunt servanda). If the authority finds that long-term capacity contracts were prematurely terminated due to the company's fault, the relating costs will (fully or partially, depending on the fault situation) reduce the allowed cost during the next cost review.

2. Quantity risk

The system operators no longer bear the quantity risk. Any revenues and costs from risks that materialised between 2013 and 2024 are retroactively accounted for, without applying any interest.

IV. Treatment of incremental capacity from planned investment projects

The costs and quantities forecast for incremental capacity at new or existing entry/exit points must be itemised per project and per flow direction. The definition of incremental capacity in Article 3(1) CAM NC applies.

Unless otherwise decided by the regulatory authority, the revenues expected from the quantity projected for the incremental capacity must be such that they cover the respective project's costs. An official decision will be issued to lay down these costs.

Costs arising from planned investments are generally handled as described in chapters II.1, II.3, II.4 and II.5 of this document. Regardless of any reconciliation of the related CAPEX (as per chapters II.1 and II.14), the planned OPEX are compared to the actual OPEX at the end of the period when they first occur and the accounts are reconciled. From then on, the actual OPEX become part of the total OPEX in accordance with the methodology then in force. Transported quantity is included in the calculation on the basis of planned values. If the project is realised, quantities are determined in future as described in chapter III.

V. Compensation payments – section 70(2) 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.

The compensation payments are then executed on a "pay-as-earned" principle, meaning the share of the planned payments in the planned transmission tariff revenues of the paying company is used to determine the actual payment due as a share of the company's actual transmission tariff revenues. For more details, please consult chapter 1.5 of the reference price methodology (annex 3a to the 2nd amendment 2024 to the Gas System Charges Ordinance 2013).

VI. Innovation budget

During the fifth regulatory period, gas TSOs are granted an annual lump sum for innovation of 0.6% of the controllable OPEX. This is meant to strengthen innovation among Austrian TSOs. The innovation budget provides companies with the necessary financial resources to transform the Austrian gas grid in the interest of long-term security of supply (cf. section 79(1) Gas Act 2011). The grid will need to be transformed for the use of renewable gas in line with the European and national decarbonisation targets.

The innovation budget targets innovations in security of supply, H2 readiness and alternative uses of the grid, digitalisation, reduction of methane emissions, redimensioning of networks (economic tests), and energy efficiency improvements. Please note:

- The costs that are necessary for system operators to fulfil their statutory duties as gas TSOs under section 58(1) Gas Act 2011 are recovered through the allowed cost and cannot be double counted as innovation.
- Borrowing from section 2(20) Public Procurement Act 2018, innovation is defined as the introduction or realisation of new or radically improved processes and methods for operating gas networks.
- Research, in this context, must focus on making the Austrian gas grid fit for the future, i.e. for decarbonisation and the energy transition.[4] There must also be a realistic expectation that the results will be useful in practice.

In the interest of efficiency, R&D projects can be carried out by the network operators individually or as a project consortium. Again, there can be no double recovery, neither through the allowed cost for the network operators nor through financing of external research bodies. Also, research partners must be selected in a non-discriminatory way.

If any innovation budget is left over after the end of the regulatory period, the system operators' allowed costs for the next regulatory period are reduced accordingly. This returns these sums to the system users by way of lower system charges. The principle of recovering actual costs (section 79(1) Gas Act 2011) is complied with and the budget is only used for the defined purposes. Of course, CAPEX that are considered by way of the CAPEX compensation or

[4] Cf. the legislative materials on public procurement reform (explanatory notes on the government bill 69 in the annexes, legislative period XXVI, p. 11).

OPEX that are already covered by the cost path cannot be double counted in the innovation budget either.

Unused budget is not returned to users annually, because R&D projects usually have multi-year lifespans. This also enables system operators to save up or use the budget flexibly along the regulatory period.[5] However, if it becomes clear that a significant part of the funds will not be used, they can be returned ahead of time.

Each system operator must report on how the innovation budget has been used on an annual basis, by 31 March of the following year. They can also issue joint reports. Please note that the results funded through the innovation budget must not be kept confidential, inside the individual system operator, but must instead be made available to the entire industry, to attain the largest possible benefit. This is meant to ensure that e.g. students can benefit from the project results. To enable this, system operators must publish their projects, including a clear description, at least on their own website.

In addition, and without prejudice to any and all further rights to information of and inspection by the authority, the companies must inform the authority about the process for selecting the projects and all economic and technical parameters of these projects, if so requested. Should the authority find that a project is not useful or does not constitute an innovation as defined above, or if it cannot be categorised into one of the areas mentioned above, the funds for such project cannot be recovered from the innovation budget. Instead, the corresponding portion of the innovation budget is returned to the system users.

[5] Please note that the innovation budget that is not used during a year is not inflated by any index.