Review of the regulatory regimes and business mixes for relevant European comparators to strengthen the use of European beta data

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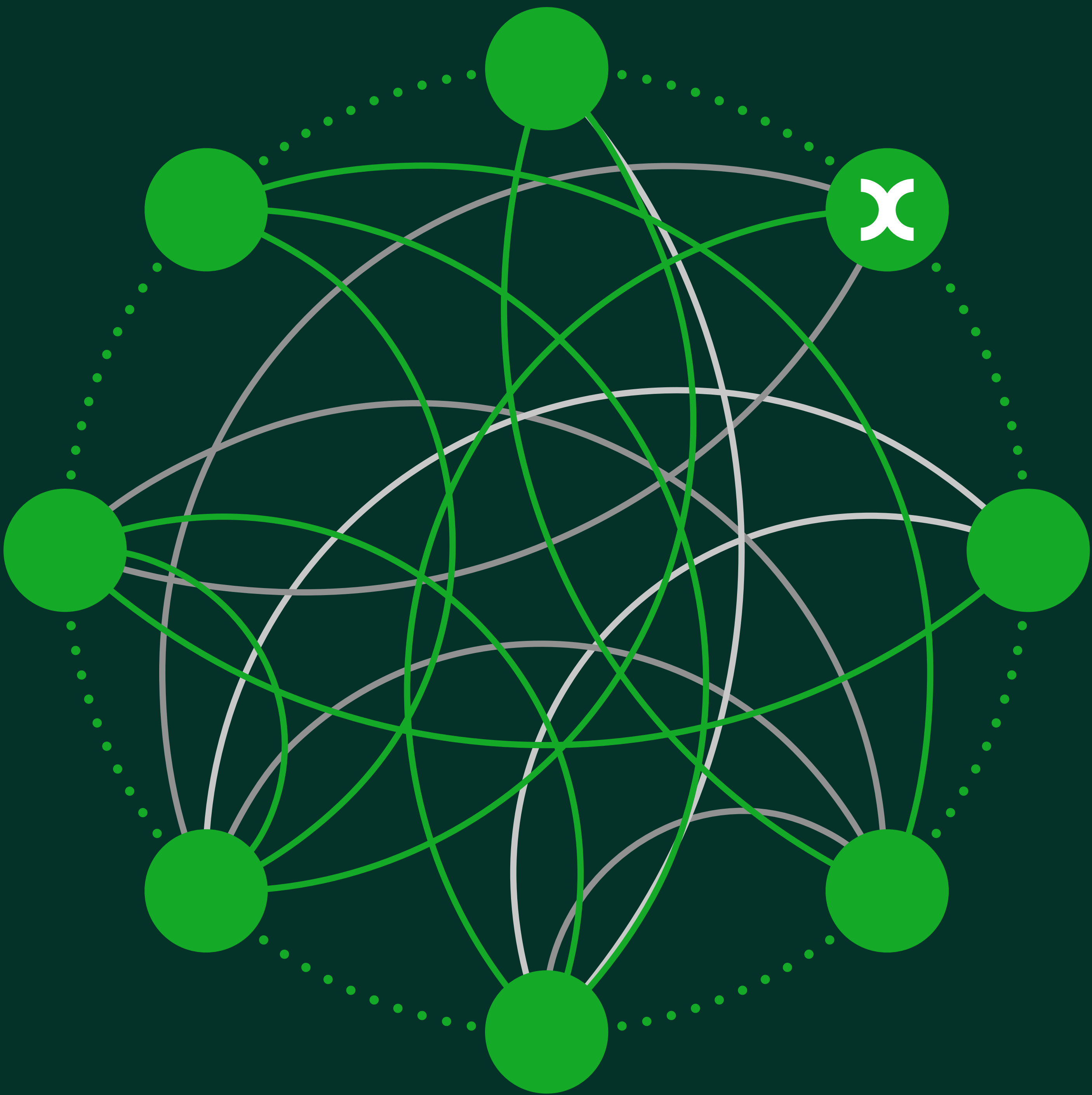
Prepared for Energy Networks Association

8 November 2024



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Executive summary

As part of the process to set allowed returns for the next round of network price controls (RIIO-3), Ofgem is minded to include a set of listed European energy networks, to act as additional comparators when it evaluates systematic risk. This is due to a shortage of listed UK comparators, with none of the UK comparators being a 'pure play' GB energy network.

Ofgem notes that while the listed European comparators operate in different countries and under different regulatory regimes, they are likely to face similar challenges to GB energy networks.[1] Ahead of the Draft Determinations, Ofgem will consider further whether the regulatory regimes and business mixes of these European comparators are suitably similar to GB networks.[2] In this report we present information on the regulatory regimes and business mixes of the five additional listed comparators identified by Ofgem (Enagás, Redeia, Italgas, Snam, Terna). We assess whether there is evidence that these comparators are exposed to similar, higher, or lower risk than networks subject to regulation under RIIO-2.[3]

We find that the share of the comparators' revenues from regulated networks in Spain or Italy accounts for the most significant portion of the companies' revenues: for the Italian companies Terna, Snam and Italgas, 87%, 69% and 93% respectively, for Redeia and Enagás (based in Spain), 86% and 92% respectively.[4] That leaves the risks of smaller parts of these companies (which are mostly represented by activities regulated under other regulatory regimes) unassessed. As with the UK comparators, none of these are 'pure play' energy networks, but we consider that their business mixes are suitably comparable to GB networks[5].

Our primary source for assessing the regulatory regimes has been the decisions published by the regulators. We have also reviewed the

[1] Ofgem (2024), 'RIIO-3 Sector Specific Methodology Decision – Finance Annex', para. 3.197.
[2] Ofgem (2024), 'RIIO-3 Sector Specific Methodology Decision – Finance Annex', para. 3.199.
[3] As the details of RIIO-3 and the risks companies will be exposed to are still emerging, our assessment of comparability focuses on RIIO-2.
[4] Based on the proportions of revenues of business segments regulated under the assessed regulatory frameworks. The percentages are based on 2019 data, which would be in the middle of the sample of data if a ten-year period was used to estimate beta.
[5] For example, Severn Trent derived 92% of its 2024 revenues from regulated water and wastewater activities and National Grid had 42% of its 2024 revenues contributed by Ofgem-regulated subsidiaries. Source: Oxera analysis based on Severn Trent, 2024 Annual Report, p. 229 and National Grid, 2023–24 Annual Report, p. 137.

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summary information provided in the latest Council of European Energy Regulators' (CEER) report on regulatory frameworks.[6]

We find that risk factors relating to the regulatory process are similar across the British, Italian and Spanish regimes. Either the competition authority or a court hears an appeal rather than makes a redetermination. The regulators in these countries have powers to operate independently. Regulatory frameworks in all three countries have been broadly consistent over time, with methodologies and parameters being updated at each price control review.

We also find that the design of the regulatory regime for energy networks is broadly similar across these jurisdictions. Companies are largely insulated from demand risk but face exposure to the risk that actual costs differ from the regulatory allowances. Although in Italy and Spain operating expenditure and capital expenditure are regulated separately rather than being regulated as total expenditure (TOTEX), overall, we consider the level of cost risk to be broadly comparable to the regulation of TOTEX under RIIO-2.

The results of our assessment are summarised in the table below.

Summary of the regulatory regimes risk assessment

Company	**Regime (covering the majority of business activities)**	**Risk compared to RIIO-2**
Terna	Italy ET	Similar (slightly towards lower risk)
Snam	Italy GT	Similar (slightly towards lower risk)
Italgas	Italy GD	Similar (slightly towards lower risk)
Redeia	Spain ET	Similar
Enagás	Spain GT	Similar (slightly towards higher risk)

Note: ET—electricity transmission; GD—gas distribution; GT—gas transmission.
Source: Oxera analysis.

[6] CEER (2024), ' Report on Regulatory Frameworks for European Energy Networks 2023', 21 February, available at: https://www.ceer.eu/wp-content/uploads/2024/04/RFR23-Main-report.pdf (accessed 26 September 2024).

As outlined in the table, we found that the Italian and Spanish regulatory regimes have broadly similar risks to RIIO-2, although:

- Italian networks' regulatory framework is slightly lower risk due to CAPEX being largely passed through;
- Spanish GT networks' regulatory framework is slightly higher risk due to CAPEX incentives being associated with greater regulatory discretion.

As a result of the assessment, we consider it appropriate for Ofgem to include the five European networks in its comparator sample.

1 Introduction

In the SSMD, Ofgem has provisionally decided to expand the sample of companies used as beta comparators by adding five European companies with regulated energy networks, namely:

- Enagás and Red Eléctrica (now Redeia)[7] in Spain;
- Italgas, Snam and Terna in Italy.

We report the relevant excerpt from the SSMD Finance Annex below.

'We plan to include Enagas and Red Electrica in Spain and Italgas, Snam and Terna in Italy. This is not a final decision, and will consider this further between SSMD and DDs to ensure that the regulatory regimes and business mixes of these European comparators are suitably similar.'[8]

As we show in this report, each of the five European comparators generates the majority of their revenue from a single regulatory regime. In particular:

- Terna is regulated under the Italian electricity transmission (Italy ET) regime;
- Snam is regulated under the Italian gas transport (Italy GT) regime;
- Italgas is regulated under the Italian gas distribution (Italy GD) regime;
- Redeia is regulated under the Spanish electricity transmission (Spain ET) regime;
- Enagás is regulated under the Spanish gas transport (Spain GT) regime.

These regulatory regimes are compared with RIIO-2[9] across a number of risk factors deriving from either the regulatory process or the design of the regulatory regime.

[7] In 2022 the Red Eléctrica Group changed its brand name to Redeia. See: https://www.ree.es/en/press-office/news/press-release/2022/06/the-red-electrica-group-is-changing-its-brand-name-to-redeia-to-strengthen-its-positioning-as-a-global-manager-of-essential-infrastructures (accessed 17 September 2024).
[8] Ofgem (2024) 'SSMD Finance Annex', para 3.199.
[9] We do not compare against RIIO-3 as details of the regime are still to be confirmed and will not be reflected in share prices over the historical periods used for beta analysis.

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Risk factors relating to the regulatory process include:

- appeal regime;
- examples of political interference;
- regulatory independence;
- regulatory consistency.

Risk factors relating to the design of the regulatory regime include:

- balance of upside opportunity and downside risk (profit buffer);
- cost efficiency incentives (including OPEX, CAPEX and cost of debt);
- demand risk.

The rest of the report is structured as follows.

- In section 2, we consider the business mixes of the five European comparators.
- In section 3, we compare the regulatory regimes of the five European comparators with GB energy networks.
- In section 4, we conclude.

2 Business mix of the European beta comparators

In this section we evaluate data on the proportion of revenue that is regulated, and specifically the proportion of revenue that derives from the Italian and Spanish regulatory regimes that we assess, to ensure that the five European comparators all have high proportions of regulated revenues.

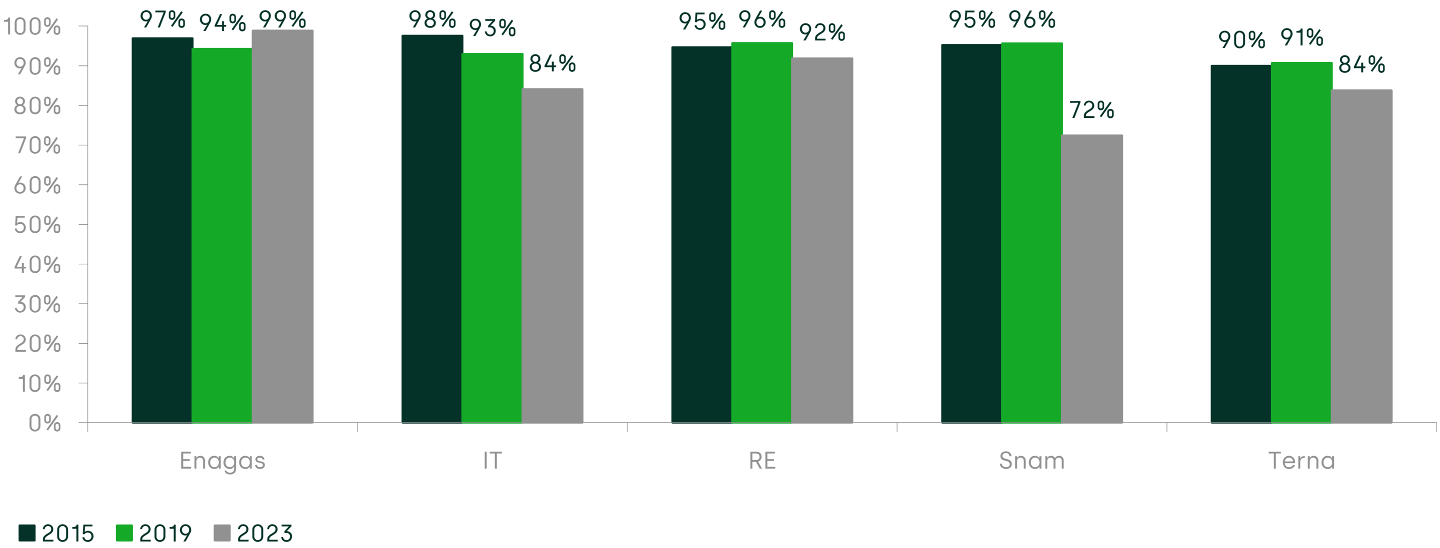
2.1 Business mix based on the proportion of revenue that is regulated

Figure 2.1 shows that the proportion of revenues from regulated activities is 86% on average across all companies, based on data from 2023. We have also checked the robustness of our results by considering the percentage of revenues from regulated activities in 2019 and 2015.[10] The results show that, both in 2019 and 2015, all the companies in our sample also had high proportions of regulated revenues, on average equal to 94% and 95% respectively.

We note that the decrease in the proportion of revenue classified as regulated activities for Snam between 2019 and 2023 is mainly driven by the growth in the 'energy transition business' segment, which includes biomethane, hydrogen, CCS, energy efficiency and small-scale LNG technologies. The decrease in the proportion of revenue from regulated activities for Italgas is mainly driven by the growth in the 'energy efficiency interventions business' segment. The decrease in the proportion of revenue from regulated activities for Terna is mainly driven by the expansion in non-regulated activities, in particular through the acquisition of Brugg Cables in 2020. Although we observe a material decrease in the share of regulated revenue for Snam between 2019 and 2023, we conclude that all comparators show sufficiently high proportions of regulated revenue in each year. Focusing on data from 2019 (as this represents the mid-point of the ten-year period for the beta estimation), all companies show a proportion of regulated revenue above 90%.

[10] We decided to focus on data from 2019 and 2015 as these years represent respectively the mid-point and the starting point of a ten-year period for the beta estimation.

Figure 2.1 Proportions of revenues from regulated activities

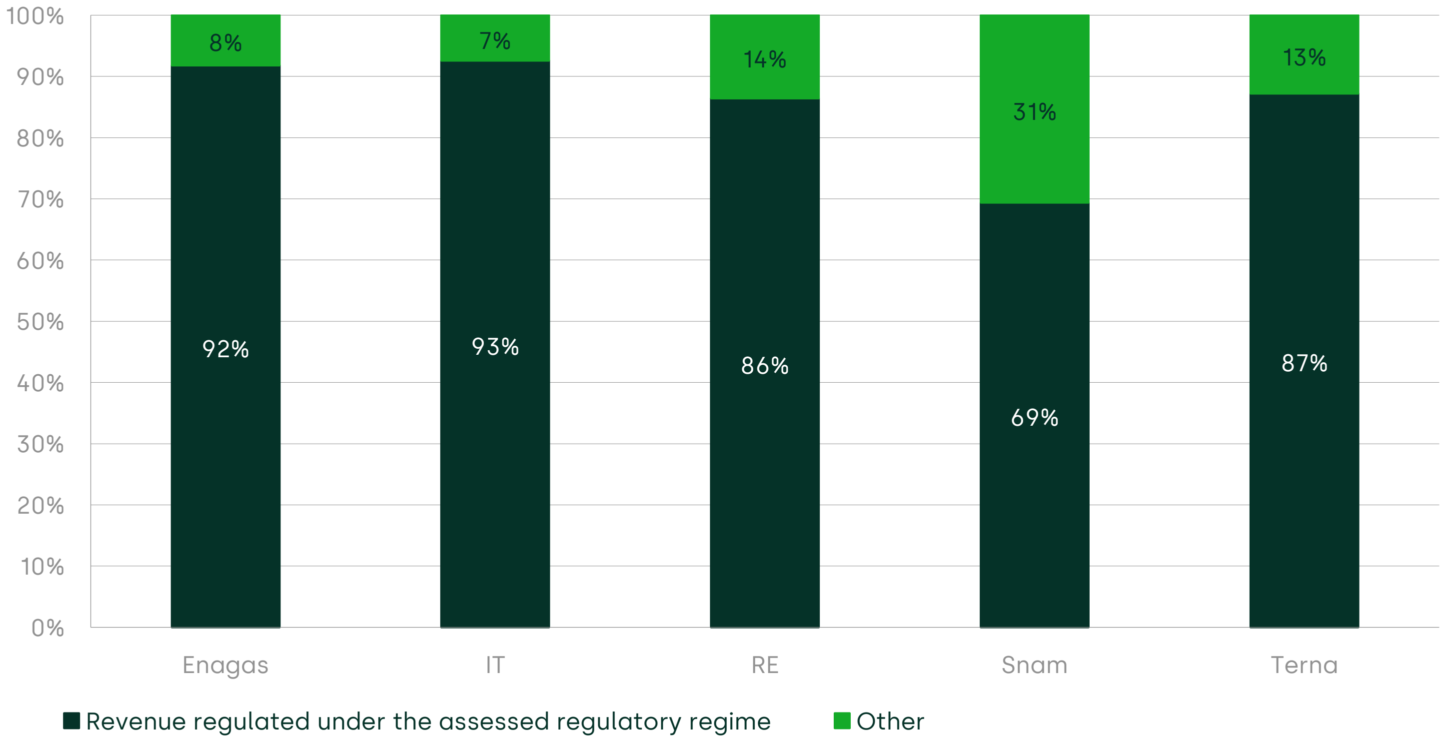


Note: IT = Italgas. RE = Redeia. Based on 2015, 2019 and 2023 data.
Source: Oxera analysis based on companies' annual reports.

2.2 Business mix based on the proportion of revenue that is regulated under the main domestic regulatory regime

In addition to the proportions of revenues sourced from regulated activities, we check how much revenue is sourced from the activities regulated specifically under the main domestic energy network regulatory frameworks. Figure 2.2 below shows the breakdown based on 2019 data. We focus on data from 2019 as this year represents the mid-point of a ten-year period for the beta estimation.

Figure 2.2 Proportions of revenues regulated under the assessed regulatory frameworks based on data from 2019



Notes: Based on 2019 data. IT = Italgas. RE = Redeia'. For Enagás, revenues from Enagás Transporte S.A.U. and Enagás GTS S.A.U. are classified as revenue derived from the assessed regulatory regime. Revenues from Enagás Transporte del Norte S.L. are classified as 'Other revenue' (classified as regulated in Figure 2.1). For Italgas, technical assistance, engineering, IT, water distribution, water sales and gas sales are classified as 'Other revenue'. Italgas's revenue from infrastructure construction and improvements (IFRIC 12) is included in the revenue derived from the assessed regulatory regime. For Redeia, we classify revenue from Spanish telecommunications (classified as regulated in Figure 2.1) and international revenue from ET activities in Peru, Chile and telecommunication activities in Brazil (classified as regulated in Figure 2.1), and international revenue in the EU as 'Other revenue'. Snam's 'Other revenue' includes its revenue from storage, regasification, and corporate activities. Terna's 'Revenue derived from assessed regulatory regime' includes revenue from dispatching and metering and revenue from construction services performed under concession. 'Other revenue' in our classification includes 'other regulated revenues' in the company's accounts.
Source: Oxera analysis based on companies' annual reports.

Figure 2.2 highlights that the assessment of the regulatory frameworks presented in the remainder of this report covers at least 86% of revenues for all comparators except Snam. In addition to GT, Snam operates gas storage and regasification activities, which also involve gas assets in Italy subject to economic regulation by ARERA.[11] Although

[11] Although the regulatory frameworks for these sectors have some specific mechanisms, and they are exposed to different operational risks, the general framework appears to be fairly similar to GT.

an assessment of these other activities would complement our analysis, the findings of our analysis provide a basis to compare the systematic risk of these companies against the RIIO-2 regime.

Considering that all the comparators show high proportions of revenue that derives from the regulatory regimes that we assess, we conclude that the assessed regulatory regimes can be considered the main driver of the regulatory risk component of the comparators' asset betas.

2.3 Conclusions on the business mix assessment

We find that the share of the comparators' revenues from regulated networks in Spain or Italy accounts for the most significant portion of the companies' revenues: for Terna, Snam and Italgas, 87%, 69% and 93% respectively, for Redeia and Enagás, 86% and 92% respectively.[12] That leaves the risks of smaller parts of these companies (which are mostly represented by activities regulated under other regulatory regimes) unassessed. As with the UK comparators, none of these are 'pure play' energy networks, but we consider that their business mixes are suitably comparable to GB networks.

[12] Based on the proportions of revenues of business segments regulated under the assessed regulatory frameworks. The percentages are based on 2019 data, which would be in the middle of the sample of data if a ten-year period was used to estimate beta.

3 Comparison of the regulatory regimes relative to GB energy networks

In this section we review the regulatory regimes under which the listed comparators in Italy and Spain derive the majority of their revenues. We assess whether there is clear evidence that these comparators are exposed to higher or lower risk than networks subject to regulation under RIIO-2.[13]

3.1 The role of regulatory regimes in determining risk exposure

In the case of regulated networks, the regulatory regime is a key driver of their exposure to total risk as well as to systematic risk specifically.

While regulation may to some extent mitigate underlying business risks (e.g. by making profits less sensitive to short-term upside and downside deviations in demand), the degree to which these risks are mitigated may vary across different regimes. Regulation may also introduce new risks. In particular, there is regulatory risk resulting from the exercise of regulatory discretion and potential for the regulatory approach to change over time. For example, the regulator may exercise a large degree of judgement over the level of the cost of equity allowance, and there is always a risk that the level will change significantly due to changes in methodology.

The importance of regulatory risk for regulated utility networks has been widely recognised by regulators and equity analysts. For instance, in 2012 the UK competition authority recognised that higher degrees of regulatory uncertainty might affect investor confidence in the longer term, increasing the return required to undertake investments.[14] Equity analysts also recognise the importance of regulatory risks by highlighting the impact that regulatory determinations have on share prices.[15]

[13] As the details of RIIO-3 and the risks companies will be exposed to are still emerging, our assessment of comparability focuses on RIIO-2.
[14] Competition Commission (2012), 'Phoenix Natural Gas Limited price determination', pp. 8–22.
[15] See, for example, Barclays (2024), 'Water Tech: Highlighting key areas of investor debate', 23 May, p.1; J.P. Morgan (2020), 'UK Utilities: Ofgem Draft Decision disappointing; expect weakness in NG/ and SSE today', 9 July, p. 1; HSBC (2018), 'National Grid: Regulatory obfuscation (but work in progress)', 19 December, p. 1; Morgan Stanley (2014), 'Elia System Operator SA: Supportive regulatory terms in Belgium', 1 September, p. 1; J.P. Morgan (2019), 'UK Utilities: Ofwat Business Plan Assessment – Fast-Track Boost for UU, SVT and PNN', 31 January, p. 1.

3.2 Regulatory frameworks risk assessment principles

The primary risk factors accounted for in our assessment of European regulatory regimes are outlined below. We compare all regimes with RIIO-2 to assess whether they are associated with higher or lower systematic risk.

In our assessment, we focus on the most recent regulatory periods, also taking into account the ongoing regulatory reforms for Italy ET and GT.[16] This is because we are interested in the impact of regulatory frameworks on investors' expectations and therefore stock returns over the historical period for which betas are estimated.

We split all factors into two groups:

- the **regulatory process factors** (including the appeal regime, political interference, regulatory independence, and regulatory consistency);
- the **regulatory regime design factors** (including the profit buffer factor, cost efficiency incentives and demand risk).

3.2.1 Risk factors relating to the regulatory process

We start with the risk factors relating to the regulatory process.

Appeal regime

An appeal regime creates constraints on regulatory discretion. The greater the scope of the appeal body review, the greater the constraint on regulatory discretion and, therefore, the lower the systematic risk associated with regulatory decisions.

However, the rule should be applied carefully, as it is the degree of regulatory discretion after the constraint of the appeals process that matters. If the regulator exercises less discretion (e.g. because its methodology is constrained by law) then even if the appeal regime scope does not impose an additional limit on regulatory discretion, the overall risk will still be lower.

With regard to the appeal regime itself, we draw a distinction between redeterminations, where the appeal body is required to redetermine the price control (as is the case in England & Wales water networks), and

[16] A transition to a TOTEX regime is currently ongoing, with the introduction of the new ROSS ('Regolazione per Obiettivi di Spesa e di Servizio') regime. ARERA has planned a gradual transition, with a first step ('ROSS-base') sharing many similarities with the previous regime. The first application of ROSS-base started in 2024 for ET and GT.

court procedures, where the appeal body is limited to finding whether the regulator was wrong on any of the specific grounds (as is the case for GB energy networks).

Examples of political interference

Cases of political interference lead to greater dependence of regulated returns on the political and social environment, and therefore indicate greater systematic risk.

Regulatory independence

In addition to examples of political interference, we checked for any major reasons to consider that the regulators are likely to be less independent of their governments than Ofgem. For example, in 2019 the European Commission has referred a few member states to the European Court of Justice (ECJ) for not providing their regulator with sufficient independence.[17] We assess this factor in combination with the examples of political interference.

Regulatory consistency

Any regulatory decision, especially one that requires substantial consideration and economic analysis, is associated with a degree of regulatory discretion and therefore potential systematic risk.

We follow the principle of greater regulatory consistency over time being associated with lower systematic risk.

3.2.2 Risk factors relating to the design of the regulatory regime

The risk factors associated with the design of the regulatory regime are presented as follows.

Balance of upside opportunity and downside risk (profit buffer)

If a company has an opportunity to earn revenue over and above the core building blocks (using RIIO-2 as a benchmark) without a symmetric risk of being penalised, it has the potential to create a **profit buffer**. Such a buffer may be argued to reduce systematic risk.

[17] European Commission (2019), 'Assessing the independence and effectiveness of National Regulatory Authorities in the field of energy', Publications Office of the European Union.

This potential would exist even if, in theory, the rewards and penalties are symmetrical. This is because, in practice, the target required to get the reward might be easy for the company to meet. The opposite would also apply—i.e. when revenue-earning opportunities are more negatively skewed than in RIIO-2, we consider this to increase systematic risk.

Cost efficiency incentives (OPEX, CAPEX, and cost of debt)

We consider the cost efficiency incentives in the context of CAPEX, OPEX and cost of debt in relation to the following three sub-factors.

- First, we check **how high-powered the cost-efficiency incentives are**. High-powered cost-efficiency incentives expose networks to greater deviations of actual costs from allowances and therefore to greater underlying cost risk, including any regulatory judgement applied in setting those allowances, while pass-through clauses protect companies from this. Where allowances are set ex ante, the proportions of out- and underperformance shared with customers show how high-powered the incentives are.[18]
- We then consider **how the regulator sets cost allowances**. If ex ante allowances are set for each company individually, mechanically reflecting its past performance, they account for the company's individual circumstances and regulatory discretion is limited. If ex ante allowances are based on the cost data of other companies as well—i.e. the costs are benchmarked and assessed for efficiency—the company may find it more challenging to meet the targets, and there is more scope for regulatory judgement.
- Finally, we consider **whether the regulator assesses cost efficiency after the costs have been incurred**. In particular, such mechanisms expose companies to asymmetric risk, because it is easier to identify areas of inefficiency and disallow these costs than it is to identify areas of efficiency and allow additional revenue to be earned.

Demand risk

[18] We distinguish between incentive rate and sharing rate. The Incentive rate represents the percentage of out- (or under-)performance that the company is able to retain (or required to bear). The sharing rate represents the percentage of out- (or under-)performance that has to be shared (or can be shared) with consumers. As such, the sharing rate can be computed as one minus the incentive rate.

We differentiate fixed allowed revenue (short-term protection from demand risk) from price cap (exposure to demand risk) regimes. For this exercise, we did not differentiate regimes by the timing of demand-related under-recoveries (e.g. during the price control period versus after it) or by the underlying demand risk, assuming that fixed allowed revenue regimes neutralise this risk.

Other risks associated with the design of the regulatory regime

This subsection highlights other factors associated with the design of the regulatory regime potentially affecting the exposure of regulated networks to systematic risk. However, we considered that the ones outlined above are the most common and significant drivers of differences in systematic risks between regulatory regimes. As a result, the risk factors mentioned as follows have not been considered for our comparative assessment of the design of the regulatory regime.

For example, the exposure to inflation risk varies across the regimes. In the Spanish regimes, unlike in RIIO-2, the regulatory asset base (RAB) is not indexed to inflation indices, and companies are exposed to inflation risk until the next price control re-set point. However, it is unclear whether inflation indexation increases or reduces systematic risk. On the one hand, inflation indexation protects investors from inflation risks, on the other hand, where returns are linked to inflation, nominal returns are correlated with the state of the economy, increasing systematic risk and the beta. Therefore, we have not included this factor in our assessment.

There are many more factors that could have been considered, such as indexed or fixed allowances for Real Price Effects (RPEs), return adjustment mechanisms, or treatment of assets funded by third parties.

In terms of comparative importance of the factors, each of the regulatory process factors affects the entire regime, while design factors relate only to parts of it. Therefore, process factors (namely, appeal regime, examples of political interference, regulatory independence, and regulatory consistency) have a greater weight in our assessment than individual design factors (namely, the balance of upside opportunity and downside risk, cost efficiency incentives, and demand risk).

3.3 Regulatory framework risk assessment—Great Britain ET, GT, GD and ED

This section assesses the regulatory regime for Great Britain ET, GT, GD and ED, to compare other regimes against it. The reviewed price control period is 2021–26 (2023–28 for ED).

3.3.1 Regulatory process

Appeal regime

Regulatory decisions can be challenged before the Competition and Markets Authority (CMA). The CMA does not conduct a full redetermination. We consider this to be comparable to court procedures where expert evidence is considered.

Examples of political interference

We are not aware of explicit examples of political interference affecting GB networks.

Regulatory independence

Ofgem is an independent regulator which sets tariffs independently from the government.

Regulatory consistency

Although Ofgem does not change regulatory principles at every price control review, it reconsiders its framework methodologies to set parameters and parameter estimates. Sophisticated methodologies and regulatory judgement are applied in the review process, introducing regulatory risk. Examples of changes between RIIO-1 and RIIO-2 price controls are as follows.

- Set of incentives—information quality incentives (IQI) were removed, the business plan incentive (BPI) was introduced, the set of output delivery incentives (ODIs) was revisited.
- Cost-efficiency incentives—the mechanism did not change; sharing rates, ex ante allowances and the efficiency factor were revised.
- Output targets were revised; new outputs were added to the outputs framework for RIIO-2, including Price Control Deliverables (PCDs).
- The risk-free rate (RfR) methodology (as an example within the cost of equity allowance methodology) moved from a combination of evidence points to spot yields on government bonds, and indexation was also introduced.
- Other methodological changes in relation to the cost of equity allowance included changes in the allowed equity beta, the allowed debt beta, and the total market return (which is now expressed in CPIH real terms and materially lower in nominal terms than in RIIO-1).

- Returns adjustments—an ex ante reduction to returns was introduced based on the expected outperformance (albeit this was overturned on appeal); threshold levels for returns were introduced. Returns above or below thresholds are adjusted downwards or upwards respectively, using an adjustment rate.
- RPEs indexation—As compared to RIIO-1, a significant proportion of forecast TOTEX allowances are now indexed for out-turn RPEs relative to CPIH to improve the recovery of nominal costs.
- Regulatory pressure—Ofgem urged networks to make voluntary contributions due to their outperformance in the RIIO-1 price control period, with most companies obtaining (real) double-digit returns. The voluntary contributions yielded over £650m in savings to customers.[19]

3.3.2 Design of the regulatory regime

Balance of upside opportunity and downside risk (profit buffer)

There are ODIs and a BPI, which are associated with both rewards and penalties. We conclude that on average they do not create a profit buffer.

Cost efficiency incentives (OPEX)

There is an ex ante total expenditure (TOTEX) allowance. The incentive rates are between 33% and 50%, implying that 50–67% of exposure is shared with customers (we refer to the latter as 'the sharing rate'). The costs of all companies in the sector are assessed in order to set TOTEX allowances.

In addition, RIIO-2 involves ex post assessment of costs and outputs. For example, price control deliverables (PCDs) allow consumers to be refunded if an output is not delivered (or not delivered to a specified standard).[20] In particular, while for mechanistic PCDs the adjustments to allowances are largely automatic and typically proportional to volumes, for evaluative PCDs the adjustments depend on Ofgem's ex-post assessment, thus entailing greater regulatory discretion and higher

[19] Ofgem (2017), 'Ofgem welcomes SGN's contribution to consumers', *Press release*, 27 November, available at: https://www.ofgem.gov.uk/press-release/ofgem-welcomes-sgns-contribution-consumers (accessed 8 October 2024).
[20] Cost-efficiency assessment is mentioned only indirectly: in cases of underspend, networks need to demonstrate that the underspend is attributable to efficiencies or innovation rather than non-delivery. However, given the required detailed ex post assessment, we consider it unlikely that cost efficiency would not be included within the scope of the assessment. See Ofgem (2021), 'Guidance – PCD Reporting Requirements and Methodology', paras 5.3–5.4.

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risk.[21] Evaluative PCDs account for a substantial share of allowed TOTEX.[22]

Cost efficiency incentives (CAPEX) As per OPEX.

Cost efficiency incentives (cost of debt)

The cost of debt allowance is based on the iBoxx GBP Utilities 10+ years trailing average, set to match the sector average actual cost of debt. The companies face the risk that this does not correspond to their actual cost of debt.

Demand risk

A fixed allowed revenue is in place.

3.4 Regulatory framework risk assessment—Italy ET, GT and GD

3.4.1 Overview of Italy ET, GT and GD

The regulatory regimes under which Terna (ET), Snam (GT) and Italgas (GD) operate are quite similar, being regulated by the same independent regulatory authority, the Autorità di Regolazione per Energia Reti e Ambiente (ARERA). However, certain mechanisms and incentives differ in order to account for the peculiarities and challenges of each sector. Specifically, a 'hybrid' approach, based on a rate-of-return regulation for CAPEX and a price cap on OPEX, has been in place until recently for ET and GT (and ED), and is still in place for GD.

A transition to a TOTEX regime is currently ongoing, with the introduction of the new ROSS ('Regolazione per Obiettivi di Spesa e di Servizio') regime.[23] ARERA has planned a gradual transition, with a first step ('ROSS-base') sharing many similarities with the previous regime. The first application of ROSS-base started in 2024 for ET and GT. Especially with the introduction of the new ROSS regulation, ARERA has increased the consistency between sectoral frameworks for Italian energy networks, which is therefore higher than it was in the past.

Each sector has a specific regulatory period, and until recently there were differences in the length of the periods between sectors. The new

[21] Ofgem (2021), 'Guidance – PCD Reporting Requirements and Methodology', para 3.2.
[22] For example, Scottish Hydro Electric Transmission's (SHE-T) evaluative PCDs have a total value of £869m. Expressed as a percentage of SHE-T's TOTEX allowance, this corresponds to approximately 32% of the allowance. See Ofgem (2021), 'RIIO-2 Final Determinations – SHET Annex (REVISED)'.
[23] The literal translation of the acronym ROSS is Regulation based on Expenditure and Service Objectives, which is similar to the RIIO concept.

ROSS regulation set a four-year regulatory period for all energy networks, although the control periods can start at different points in time (for legacy reasons). In particular:

- the latest regulatory period for ET (Terna) and GT (Snam) started on 1 January 2024 and will last for four years (2024–27);
- the current regulatory period for GD (Italgas) runs from 2020 to 2025. The new regulation will apply from 2026.

A separate control period, the PWACC, is in place for the WACC allowance. This is defined on the basis of a methodology (the TIWACC) that is common to all energy networks, although some parameters are sector-specific (i.e. gearing and asset beta). The WACC period is divided into two sub-periods, each lasting three years, at the end of which (most of) the parameters are reviewed.[24]

The few key differences between the GD, GT and ET regulatory regimes in Italy, under which the networks in question operate, are as follows.

- Up to the end of 2023 (i.e. the end of the previous control period), there were stricter rules on the extent to which CAPEX expenditure could be added to the RAB in GT compared with ET and GD. In particular, in GT, for projects above a certain monetary value, the amounts added to the RAB depend on the projects' benefit-to-cost ratios. From 2024, ET and GT share a similar risk (as similar provisions have been introduced for ET), which remains higher than in GD. In contrast, in GD a 'tariff cap' on capital charges (expressed in unit terms) is applied to investments in newly methanised areas, i.e. those first served after 2017. This does not apply to ET nor GT, but it is worth noting that newly methanised areas represent a small share of Italian municipalities.
- There is a lower remuneration, and hence higher exposure to the risk of delays, of the work-in-progress CAPEX in ET and GT than in GD—in GD, the work-in-progress CAPEX is remunerated at the WACC as in the case of any other asset, while in ET and GT it is remunerated at a lower rate and only for a limited number of years. In the past (up to the end of 2023), ET had a lower remuneration than GT.

[24] In particular, the total market return (TMR), coefficients for transaction costs (ADD), convenience premium (CP), uncertainty premium (UP) and weight of new debt are fixed for the entire PWACC period (2022–27).

- ARERA has recently introduced an incentive mechanism for maintaining in operation fully depreciated assets (when it is safe to do so) for GT, implying greater reward opportunities in that sector and hence lower risk.

Based on these factors, we conclude that the Italian GD regime may be considered to be slightly lower risk than the Italian GT and ET regimes, although the broader context for GD is characterised by some uncertainties, such as the assignment of the service through tenders.[25]

Below, we assess the regulatory regimes for Italian ET, GT and GD against RIIO-2. The reviewed price control periods are 2024–27, 2024–27 and 2020–25 respectively.[26]

3.4.2 Regulatory process

Appeal regime—Similar risk

There is no redetermination by a competition authority; rather, legal proceedings are used to investigate the administrative procedures. This is similar to the CMA only intervening if an error is found in Ofgem's determination, rather than carrying out a redetermination.

Examples of political interference—Similar risk

We are not aware of explicit examples of political interference affecting networks. We find no reason to conclude that ARERA's decisions are more or less affected by political agendas than those of Ofgem.

Regulatory independence—Similar risk

ARERA is an independent administrative authority but has to take into account the general policy guidelines introduced by the government and Parliament.

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[25] Due to national legislation, in Italy GD rights are allocated through concessions. While concessions were historically awarded at the municipality level, tenders are now required to take place on a broader scale (broadly corresponding to provinces). However, only a limited number of tenders have actually taken place (or have been concluded) to date, thus some uncertainty remains about how the service will be provided in the different areas.
[26] The price control period for GD in Italy is divided into two semi-periods. Given that the overall regulatory framework typically remains broadly constant between semi-periods (although amendments/changes can still be introduced), we assess the whole price control period as one.

Italy was not referred by the European Commission to the ECJ for failing to comply with the EU energy market rules in relation to regulatory independence.

Regulatory consistency—Similar risk

As in GB energy, potential changes to the framework, methodologies to set parameters and parameter estimates are considered at every price control review. While the move towards a TOTEX regime is currently ongoing, it is worth noting that ARERA has adopted a phased approach to ensure a smooth and gradual transition to the new model. At a high level, the ROSS-base regime currently applied for ET and GT shares some of the features of the 'hybrid' regime (RAB–WACC model with a rate-of-return remuneration system for CAPEX, combined with a price-cap mechanism for OPEX) previously in place in Italy and currently applied for GD.[27]

- Set of incentives—new incentives were introduced (e.g. incentives to obtain EU grants to finance investments or incentives for the acquisition of small transmission companies for ET, for dual-fuel compression stations for GT, or in relation to smart meters, more careful management of the delta in–out[28] and metering more generally for GD). Moreover, in 2023, ARERA introduced a new incentive mechanism for GT networks to maintain fully depreciated assets in operation, where it is safe to do so, thereby creating additional opportunities for rewards and lower risk.[29]
- Cost-efficiency incentives—for GD, the mechanism is largely unchanged compared to the previous regulatory period. A different cost-sharing mechanism has been introduced for ET and GT as part of the ROSS-base regime. This combines a TOTEX incentive mechanism for savings attributed to capital expenditures (currently not 'directly' applied, as CAPEX is largely passed through) and a rolling incentive mechanism for savings attributed to operating expenditures.
- Output targets—some outputs and/or specifics of the design of certain incentive mechanisms were revised relative to the

[27] One of the main changes introduced with ROSS-base consists in identifying the costs that are recovered in-year (i.e. the fast-money component) and those logged to the RAB (i.e. the slow-money component) according to a given capitalisation rate set ex ante by the regulator.
[28] The delta in-out refers to the difference between the gas volumes injected in the exit points of the GT network interconnected with GD networks (city gate) and the volumes withdrawn by final consumers connected to the distribution network.
[29] ARERA (2022), 'Delibera 723/2022/R/gas', December.

previous price control—e.g. some mechanisms relating to quality for GD.

- Rate of return methodology—at a high level, some aspects of the methodology for setting the WACC have remained unchanged from the previous WACC period. The allowance is set for a period of six years, with a mid-period update. The methodology for the following WACC period is split into two semi-periods, with most of the parameters undergoing redetermination at the start of the second sub-period. However, the regulator introduced several changes in order to refine the methodology to compute some of the parameters and protect investors from variations in macroeconomic conditions. These include the below.
    - A trigger mechanism (with a pre-defined threshold) has been introduced to update the WACC if market parameters undergo significant variations intra-period. This mechanism was introduced for the first semi-period of the current WACC period (2022–24).[30]
    - RfR methodology—the RfR is estimated with reference to AAA and AA rated EUR-denominated government bonds (while previously, it was estimated with reference to the yield on Italian government bonds). In 2015, an RfR floor of 0.5% was introduced but has now been removed. Furthermore, the new methodology considers three premia in the RfR calculation, namely the convenience premium, the uncertainty premium, and the forward premium.
    - Cost of debt methodology—before 2015, the cost of debt was estimated as the sum of the RfR, a country risk premium, and a debt premium. Under the current methodology, ARERA estimates the cost of debt as the average between the cost of existing debt and the cost of new debt using market indices. A mechanism ensures a gradual transition from the old to the new methodology through the inclusion of a fixed term in the WACC calculation (the weight of which decreases over time).

3.4.3 Design of the regulatory regime

Balance of upside opportunity and downside risk (profit buffer)— Similar risk

[30] Based on the latest consultation document ahead of the mid-period review of the WACC methodology, ARERA is minded to confirm the trigger mechanism also for the second semi-period (2025-27). ARERA (2024), 'Consultazione 342/2024/R/com', July.

There are positive and negative effects of different elements, resulting in a broadly balanced position. Therefore, we conclude that the risk is similar to RIIO-2.

- For all sectors, work-in-progress CAPEX is treated differently from assets that have entered into operation (specifically it receives an allowed return but is not depreciated until the assets enter into operation). For ET and GT, work-in-progress CAPEX is remunerated at a lower rate than the allowed rate of return and for a maximum of four years (as a general rule). This term can be extended for a maximum of two years for certain projects with (i) costs above €1bn; (ii) an expected build time of more than four years. This is associated with slightly higher risk than in RIIO-2, where investments are recognised when they are undertaken, and work-in-progress CAPEX is not treated differently from the rest of TOTEX. For GD, work-in-progress CAPEX is remunerated at the WACC, without time limits. A more favourable treatment (which is comparable to that under RIIO-2) therefore applies for GD.
- In ET, a premium of 1% on top of the allowed WACC is recognised on investments put into operation during the period 2012–14, which is additional to the standard building blocks seen in RIIO-2. This mechanism has been phased out (i.e. has not been renewed in more recent price controls), but its application period has not yet expired.[31]
- In GT, a premium of 1.5% on top of the allowed WACC is recognised for a period of ten years on new investments entered into operation between 2020 and 2022 with a benefit-to-cost ratio higher than 1.5. This premium is on top of the standard building blocks of RIIO-2. This mechanism has been phased out (i.e. has not been renewed in more recent price controls), but its application period has not yet expired.[32]
- In GT, ARERA recently introduced a new incentive mechanism to maintain fully depreciated assets in operation, where it is safe to do so, thereby creating additional opportunities for rewards.[33]
- In ET, some output-based incentive mechanisms linked to service quality (e.g. in relation to ENS, continuity, or interruptions) are asymmetric. For example, the cap on penalties for ENS is lower than that on rewards, therefore implying more opportunities for upside than downside, while continuity and interruptions can

[31] ARERA (2023), 'Delibera 615/2023/R/eel', Attachment B, December, para. 4.6.
[32] ARERA (2023), 'Delibera 139/2023/R/gas', Attachment A, April, para. 6.2.
[33] ARERA (2022), 'Delibera 723/2022/R/gas', December.

only result in costs for Terna (with exposure to the sole downside risk). At the same time, some incentive mechanisms can only result in rewards (e.g. incentives to obtain EU grants to finance investments, or incentives for the acquisition of small transmission companies). Although the exact balance is unclear, this is in principle similar to RIIO-2, where some output-based incentives are asymmetric (e.g. output mechanisms such as the timely connection ODI-F for NGET result only in penalties, while others such as the SO:TO optimisation ODI-F for NGET result only in rewards).

Cost efficiency incentives (OPEX)—Similar risk

For ET and GT, the OPEX baseline is set differently under the ROSS-base regime. In particular, the allowed OPEX in the first year of the period is set on the basis of actual costs in the base year (with a company-specific assessment). In the following years, the allowance is updated for (i) inflation; (ii) an annual efficiency factor (*X-factor*, set by ARERA at the beginning of the period, that varies depending on the cost sharing option chosen by the network operator);[34] (iii) two additional factors to account for incremental OPEX resulting from unforeseeable and exceptional events and/or changes in the policy framework (*Y-factor*) or related to new investments linked to the energy transition (*Z-factor*). Moreover, a new cost sharing mechanism applies on a yearly basis (with a lag, once outturn data become available) to deal with deviations between the OPEX baseline and outturn costs. Specifically, savings attributed to operating expenditures are subject to a rolling incentive mechanism, with different incentive rates depending on the 'option' (low- or high-powered option) chosen by the network operator at the beginning of the period.[35] Overall, we consider the risk associated with OPEX allowances for ET and GT to be broadly similar to RIIO-2.

For GD, there is full exposure to out- and underperformance of costs over the course of the regulatory period in which these are incurred. In addition, the targets are set in a way that strengthens the incentive—the target OPEX in the first year of the regulatory period is set on the

[34] The network operator can choose between a low-powered incentive (SBP) and a high-potential incentive (SAP). Under the SBP, the incentive rate is 100% in the first year the (in)efficiency is incurred) and 50% in the subsequent three years. Under the SAP, the incentive rate is 100% in the first year the (in)efficiency is incurred and 75% in the subsequent three years (but with a 'cap' to penalties in case of structural underperformance). The *X-factor* is 0% for the SBP and 0.50% for the SAP (annual values). See: ARERA (2023), 'Delibera 497/2023/R/com', October and ARERA (2023), 'Delibera 163/2023/R/com', April.

[35] Both Terna and Snam chose the low-powered option. See: ARERA (2023), 'Delibera 632/2023/R/eel', December and ARERA (2023), 'Delibera 216/2024/R/gas', May.

basis of actual OPEX in the base year + 50% of out- or underperformance in the base year, instead of being linked to the actual OPEX in the base year. The incentive is more high-powered than in RIIO-2 and therefore would imply higher risk. Moreover, ex ante allowances are set on the basis of regulatory accounting data for the whole sector/cluster, thus potentially resulting in allowed OPEX being higher or lower than actual OPEX. Conversely, OPEX allowances are set according to specific formulas, thereby providing fewer opportunities for regulatory discretion and thus implying lower risk. Moreover, under specific circumstances, there is a possibility for ex-post recovery of cost overruns if these are fully justified (e.g. costs resulting from unforeseeable and exceptional events or from changes in the policy framework). This is comparable to RIIO-2 uncertainty mechanisms. On balance, we consider the risk associated with OPEX allowances to be similar to RIIO-2.

Cost efficiency incentives (CAPEX)—Lower risk

For all the three sectors, at the moment there are no efficiency targets on CAPEX, as allowances are set at the level of costs incurred in year T-1, which is similar to a cost-plus basis with a lag. There are also no opportunities for regulatory discretion. We consider this to be lower risk than in RIIO-2.

There is an ex ante downwards adjustment to CAPEX allowances in GT if the benefit-to-cost ratio is below one and the amount of investment meets certain thresholds (the cost–benefit assessment is limited to investments >€25m for the national network or >€5m for the regional network)—in these cases, investments are included into RAB for a value corresponding to that of the benefits. From 2024, similar provisions have also been introduced for Terna (ET), specifically for investments included in its ten-year network development plan, aligning the treatment of investments in GT and ET—although this regulatory treatment was not aligned in the previous control period. Although no ex ante downward adjustments are undertaken based on benefit-to-cost ratios in RIIO-2, companies' investment plans are scrutinised, which leads to downward adjustments to ex ante allowances. While more limited in its application, GD also has some unit-cost mechanisms (e.g. for smart meters, but these represent a small share of total costs), while a tariff cap (defined in €/PdR)[36] applies for CAPEX allowances in newly methanised areas, where gas supply first started after 2017 (if capital charges are above the cap, actual costs are not recovered in

[36] PdR stands for point of re-delivery.

full). However, we do not consider this factor to outweigh a generally lower-powered and lower-risk incentive mechanism.

Cost efficiency incentives (cost of debt)—Similar risk

The cost of debt is not company-specific; instead, and similar to RIIO-2, it is set at the same level for all the Italian electricity and gas networks. Under the current methodology, the cost of debt is a weighted average of the cost of existing debt and the cost of new debt, both calculated by reference to market data.

Demand risk—Similar risk

In GT, there is volume risk on less than 1% of the allowed revenue, due to the capped risk exposure on the OPEX component.[37]

In GD, there is no demand risk exposure due to ex post corrections.

In ET, 7% of revenue is exposed to volumes. However, when considered together with the expected level of demand volatility, the volume exposure of the allowed revenue is widely referred to as 'negligible' or 'limited'. Therefore, we do not put much weight on it.[38]

3.5 Regulatory framework risk assessment—Spain ET and GT

3.5.1 Overview of Spain ET and GT

Enagás (GT) and Redeia (ET) share similar regulatory frameworks, being regulated by the same independent regulatory authority, the Comisión Nacional de los Mercados y la Competencia (CNMC)[39]. Both are subject to RAB–WACC regimes with ex ante cost incentives on CAPEX and OPEX, and a set of output-based incentives tailored to the sector. A specific component—the remuneration of the useful life extension (REVU)—is applied to both GT and ET, to incentivise networks to maintain fully depreciated assets in operation when it is safe to do so.

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[37] See for example Snam (2023), '2023 EMTN UPDATE-BASE PROSPECTUS', p. 21 (accessed 20 September 2024).

[38] See BANCA IMI (2020), 'Company Note. Terna', p. 1. Moody's (2020), 'Regulated electric and gas networks – EMEA', 2 December, p. 24, Exhibit 22. See also Terna (2024), '2024 Base Prospectus. Euro Medium Term Note Programme', p. 192 (accessed 20 September 2024).

[39] In February 2024 the Spanish government approved a draft bill to carve out the energy regulator (CNE) from the current CNMC regulatory body in order to have a 'specialised regulator and watchdog' in light of the energy transition. See: Montel News (2024), 'Spain to split market watchdog, appoint new energy regulator', 20 February, available at: https://montelnews.com/news/4709b852-2bef-4a01-9d2c-c1da450c34d0/spain-to-split-watchdog-appoint-new-energy-regulator#:~:text=(Montel)%20The%20Spanish%20government%20approved,new%20energy%20regulator%2C%20the%20CNE (accessed 15 October 2024).

Both the ET and GT networks are subject to a six-year regulatory period, although they start at different points in time. In particular:

- the current regulatory period for ET (Redeia) runs from 2020 to 2025;
- the current regulatory period for GT (Enagás) runs from 2021 to 2026.

Moreover, in 2019, a new methodology to set the financial remuneration was established for all energy sectors.[40] The WACC is now used instead of adding a spread (and an additional 'remuneration for the continuity of supply' component in GT) on top of the average yield on Spanish government bonds.

While, below, we describe the key features of the Spanish regulatory frameworks against the various criteria, there are certain differences between the two regimes that can be summarised as follows.

- The GT regime has a lower exposure to underperformance on OPEX. Both ET and GT are fully exposed to out- and underperformance of OPEX over the course of the regulatory period, although the allowed OPEX is set differently at the beginning of each regulatory period—in ET, poor performers get lower allowances and strong performers get higher allowances, while in GT, only the strong performers get higher allowances but the poor performers' allowances are not reduced.
- In ET, when deviations of actual costs from allowances are significant, different sharing rates are applied to out- and underperformance on CAPEX, with sharing rates on outperformance being higher than sharing rates on underperformance. This negatively asymmetric mechanism implies a higher risk for ET networks, as a symmetric mechanism applies for GT. However, there are ex post efficiency adjustments in GT that may apply to CAPEX regardless of whether the deviations are significant, implying a higher risk for GT networks. Given that the ex post adjustments may apply to CAPEX in all circumstances, we put more weight on them than on the difference in sharing rates, and therefore conclude overall that the risks associated with CAPEX incentives are greater in the GT sector.

[40] We note that the CNMC has recently launched a consultation to modify the tariff regulation for ET for the 2026–31 regulatory period. According to the CNMC, the methodology shall be adapted to the changes derived from the decarbonisation process, including the need for development of infrastructure and the efficient use of existing networks. See CNMC (2024), 'CIR/DE/007/24', June.

- There is an RCS component (the remuneration for the continuity of supply) in GT, which is still in place but is being phased out, and which potentially creates opportunities for additional revenues in GT.

Given that different components of the regulatory regime suggest different findings of the balance of risks between Spanish GT and ET, we conclude that the overall risks are broadly comparable.

Below, we assess the regulatory regimes for Spanish ET and GT against RIIO-2. The reviewed price control periods are 2020–25 and 2021–26 respectively.

3.5.2 Regulatory process

Appeal regime—Similar risk

Regulatory decisions can be challenged before the National High Court (NHC). No redetermination is undertaken by a competition authority; rather, legal proceedings are used to investigate the administrative procedures. This implies a similar risk to RIIO-2.

Examples of political interference—Similar risk

We are not aware of explicit examples of political interference into the CNMC's regime. We therefore mark this factor as indicating similar risk.

Regulatory independence—Similar risk

Since 2020, an independent regulator, the CNMC, has been provided with more powers and regulatory independence. After its appointment four years ago, the CNMC set the regulatory framework in all energy sectors, partially maintaining continuity with respect to the previous regimes. Overall, regulatory independence has been comparable to that of Ofgem. As our focus is on the most recent price control, we mark this factor as similar risk.

Regulatory consistency—Similar risk

In 2020, when the CNMC was provided with additional powers, the regulatory framework was broadly maintained consistent with the previous regulatory period. As in GB energy, before the start of every regulatory period, methodologies and parameters can be updated.

- Set of incentives—for GT, a specific component, the REVU (remuneration for useful life extension) has been strengthened, i.e. higher OPEX allowance recognised for fully depreciated assets to maintain these assets in operation. For ET, a REVU component was introduced. For GT, the remuneration for continuity of supply (RCS) component is being phased out gradually. There is no concept of OPEX directly linked to fully depreciated assets (REVU) or any specific component directly analogous to the RCS component in RIIO-2, therefore, the impact on risk compared with RIIO-2 is unclear.

- Cost-efficiency incentives—for ET, the CAPEX sharing mechanism has changed. Where there is a large difference between the actual and reference costs, a different sharing rate of out-/underperformance has been introduced. For ET, an efficiency parameter on OPEX has been introduced to share efficiency achieved in the previous period with network users. For ET, unit costs were not updated before the current regulatory period.
- Output targets—for ET, a change was introduced following the previous price control in the availability threshold for the incentive mechanism to maximise grid availability, in order to strengthen the incentive.
- Rate of return methodology—a new methodology to set the financial remuneration was established in 2019[41] with no further changes by the CNMC since then. The WACC is now used instead of adding a spread (and an additional RCS component in GT) on top of the average yield on Spanish government bonds.

3.5.3 Design of the regulatory regime

Balance of upside opportunity and downside risk (profit buffer)—Similar risk

There are positive and negative effects of different elements, resulting in a broadly balanced position. Therefore, we conclude that the risk is similar to RIIO-2.

- Grants are generally excluded from the RAB, but in the case of EU funds, only 90% of the amount received will be deducted from the RAB. This implies lower risk.
- Assets under construction are not included in the RAB, implying that no depreciation nor return allowance is earned until they are put into service. This implies higher risk.

[41] CNMC (2019), 'Decision 2/2019', November.

- In GT, an RCS (remuneration for continuity of supply) component is provided on top of the building blocks. The CNMC has decided to phase out this component gradually, but it has still been maintained for the current regulatory period. It potentially creates opportunities for additional revenues and implies lower risk.
- A financial prudence penalty applies to both ET and GT, for networks with ratios of indebtedness and economic financial capacity that fall outside recommended values. This is limited to a maximum of 1% of the total revenues and applies from 2023 for electricity networks, and from 2024 for GT networks. This is broadly comparable to Ofgem's tax review mechanism and its financial resilience requirements.
- In ET, incentives to maximise grid availability range from -3.5% to +2.5% of the OPEX allowance for that asset. The impact on risk is unclear as the probability-weighted range is not known.
- In both ET and GT, the REVU component allows for higher OPEX for fully depreciated assets. There is no concept of OPEX directly linked to fully depreciated assets in RIIO-2; therefore, the impact on risk compared to RIIO-2 is unclear.

Cost efficiency incentives (OPEX)—Similar risk

In ET, as in Italy, there is full exposure to out- and underperformance of efficiencies over the course of the regulatory period in which these are incurred. In addition, the targets are set in a way that strengthens the incentive—the target OPEX is set at the level of actual OPEX in the base year + 50% of out- or underperformance in the base year. The incentive is more high-powered than in RIIO-2 and would therefore imply higher risk. Conversely, base-year costs are not reduced by an efficiency factor to set the target, limited regulatory judgement is applied to set ex ante allowances, no ex post adjustments are mentioned in the methodology, and ex ante allowances are not benchmarked to other companies, which would all imply lower risk. On balance, we consider the risk associated with OPEX allowances in ET to be similar to RIIO-2.

In GT, there is also full exposure to out- and underperformance of efficiencies over the course of the regulatory period in which these are incurred. The targets are based on reference costs set by the regulator without direct reference to the company's recent actual costs. These factors would imply a higher risk than in RIIO-2. However, no ex post efficiency adjustments are mentioned in the methodology. In addition, there is an asymmetric efficiency incentive—the company can keep 50% of the outperformance achieved in the previous regulatory period. No penalty for underperformance is mentioned in the methodology. Given that these factors imply lower risk than in RIIO-2, we conclude that, on balance, the risk is similar.

Cost efficiency incentives (CAPEX)—Similar risk in ET and higher risk in GT

In ET, cost allowances are set based on reference costs, which are linked to the efficient costs necessary to build, operate and maintain the facilities.[42] The sharing and corresponding incentive rates are in the same range as those in RIIO-2, and have an element similar to the return adjustment mechanism (RAM) in RIIO-2. The details are as follows.

- If the actual costs are below the reference costs, the minimum of 50% of the difference and 12.5% of the actual costs are allowed to be added to the RAB in addition to the actual costs, limiting the company's upside.
- If the actual costs are above the reference costs, the minimum of 50% of the difference and 12.5% of the reference costs are allowed to be added to the RAB in addition to the reference costs, limiting the company's ability to share its losses with consumers.

We find these ranges to be comparable to the 33–50% incentive rates range in RIIO-2. Moreover, significantly higher costs need to be justified. We assume that poorly justified costs may not be allowed for partial recovery, which is similar to the ex post adjustments applied in RIIO-2. Overall, we consider this to be associated with a similar risk to that in RIIO-2.

In GT, cost allowances are also set based on reference costs. Unit costs are determined based on 'representative average values obtained from investment cost of facilities whose technical design and operating conditions are adapted to the standards used in the gas system, and according to the evolution of the main cost drivers considered'.[43] As in ET, we consider this to be broadly similar to RIIO-2. A 50% incentive rate is applied to out- and underperformance, which is comparable or even somewhat higher than in ET (where companies bear at most 50% of the difference) and RIIO-2 (where companies bear 33–50% of the difference). In addition, ex post efficiency adjustments may be applied to the actual costs (before sharing) in all circumstances, rather than only when the actual costs deviate from the reference costs

[42] CNMC (2019), 'Decision 7/2019', December, p. 137574.
[43] CNMC (2019), 'Decision 9/2019', December, art. 20.

significantly (e.g. as is the case for ET). Given that these adjustments are applicable to all costs, we consider this to be a greater risk than in ET or RIIO-2. Overall, we consider risk to be slightly higher than in RIIO-2.

Cost efficiency incentives (cost of debt)—Similar risk

The cost of debt allowance is set using a comparator-based approach and is not company-specific, in line with RIIO-2. We also note that, differently from RIIO-2, the CNMC makes a distinction between GT and ET.

Demand risk—Similar risk

In ET, there is no direct volume risk exposure.

In GT, there is a specific component of revenues that varies with demand (RCS). Over the 2021–26 control period, the RCS component represents on average c.20% of the allowed revenues for GT.[44] However, as the component is being phased out over the current control period and is no longer linked to demand volumes,[45] we can conclude that the demand risk is similar to RIIO-2.

3.6 Conclusions on the regulatory framework risk assessment

Based on the above assessment, we consider the Italian and Spanish regulatory regimes to be broadly similar to RIIO-2 in terms of their systematic risk, although there is still some variability.

- We assess the risk of the Italian regulatory regimes as being slightly lower than that of RIIO-2, primarily due to the CAPEX recovery mechanism being similar to a cost-plus basis. However, we consider them to be overall similar to RIIO-2 because this is just one of the factors, and all process factors and the rest of the regime design factors are similar.
- We find that the Spanish regimes are associated with similar risks to those of RIIO-2 across the factors, with one exception for GT (Enagás). We find CAPEX incentives in GT to be associated with greater regulatory discretion, and hence higher risk. This is, however, only one of the design factors, while all process factors imply similar risk.

[44] CNMC (2019), 'Decision 9/2019', December, Explanatory Report, Table 157.
[45] Enagás, 2023 Annual Report, p. 307.

Table 3.1 summarises this assessment.

Table 3.1 Summary of risk comparison by assessment criterion

Risk factor	Italy (ET, GT, GD)	Spain (ET, GT)
Regulatory process		
Appeal regime	Similar risk	Similar risk
Examples of political interference	Similar risk	Similar risk
Regulatory independence	Similar risk	Similar risk
Regulatory consistency	Similar risk	Similar risk
Design of the regulatory regime		
Balance of upside opportunity and downside risk (profit buffer)	Similar risk	Similar risk
Cost efficiency incentives—OPEX	Similar risk	Similar risk
Cost efficiency incentives—CAPEX	Lower risk	Similar risk for ET Higher risk for GT
Cost efficiency incentives—cost of debt	Similar risk	Similar risk
Demand risk	Similar risk	Similar risk
Overall conclusion	**Similar (slightly towards lower risk)**	**Similar risk for ET** **Similar (slightly towards higher risk) for GT**
Comment	**Framework similar to GB energy but with CAPEX largely passed through**	**Framework similar to GB energy, with slightly higher risk for GT due to CAPEX incentives being associated with greater regulatory discretion**

Source: Oxera.

4 Conclusions

We have assessed the business mixes and the regulatory regimes of the five additional listed comparators identified by Ofgem (Enagás, Redeia, Italgas, Snam, Terna).

As with the UK comparators, none of these are 'pure play' energy networks. However, the share of the comparators' revenues from regulated networks in Spain or Italy accounts for the most significant portion of the companies' revenues over the last ten years. We consider that their business mixes are suitably comparable to GB networks.

We assessed whether there is clear evidence that these comparators are exposed to higher or lower risk than networks subject to regulation under RIIO-2.

We found that risk factors relating to the regulatory process are similar across the British, Italian and Spanish regimes. Either the competition authority or a court hears an appeal rather than makes a redetermination. The regulators in these countries have powers to operate independently. Regulatory frameworks in all three countries have been broadly consistent over time, with methodologies and parameters being updated at each price control review.

We also found that the design of the regulatory regime for energy networks is broadly similar across these jurisdictions. Companies are largely insulated from demand risk but face exposure to the risk that actual costs differ from the regulatory allowances. Although in Italy and Spain operating expenditure and capital expenditure are regulated separately rather than being regulated as total expenditure (TOTEX), overall we consider the level of cost risk to be broadly comparable to the regulation of TOTEX under RIIO-2.

We conclude that the business mixes and the regulatory regimes of the five European comparators identified by Ofgem are sufficiently similar to GB energy networks for them to be included in the sample used to estimate the asset beta for calculating the cost of equity.

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