STUDY ON THE REGULATION OF ELECTRICITY & GAS SYSTEM OPERATORS

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The Netherlands Authority for Consumers and Markets (ACM)

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List of Abbreviations

Abbreviation	Definition
ACER	Agency for the Cooperation of Energy Regulators
ACM	Autoriteit Consument & Markt (Dutch NRA)
AER	Australian Energy Regulator (Australian NRA)
AIP	Annual Iteration Process
ARERA	Autorità di Regolazione per Energia Reti e Ambiente (Italian NRA)
ASIDI	Average System Interruption Duration Index
BDEW	BDEW Bundesverband der Energie- und Wasserwirtschaft
BfJ	Bundesamt für Justiz (Federal Office of Justice)
BMWi	Bundesministerium für Wirtschaft und Energie
BMJ	Bundesministerium der Justiz (Federal Ministry of Justice)
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (German NRA)
BPI	Business Plan Incentive
BRUGEL	Brusselse Regulator voor Energie (Brussels-Capital region NRA)
BSC	Business Support Costs
BPI	Business Plan Incentive
CAI	Closely associated indirects
CAPEX	Capital expenses
CAPM	Capital asset pricing methodology
CBA	Cost-benefit analysis
CEER	Council of European Energy Regulators
CNMC	Comisión Nacional de los Mercados y la Competencia (Spanish NRA)
CPIH	Consumer Price Index including Owner Occupiers' Housing Costs
CRE	Commission de Régulation de L'Énergie (French NRA)
CRU	Commission for Regulation of Utilities (Irish NRA)
DENA	Deutsche Energie-Agentur
DNO	Distribution Network Operator
DoE	Abu Dhabi Department of Energy
DSO	Distribution System Operator
EC	European Commission
ERSE	Entidade Reguladora dos Serviços Energéticos (Portuguese NRA)
GB	Great Britain
GHG	Greenhouse Gas
IIS	Interruptions Incentive Scheme

Abbreviation	Definition
IT&T	Information Technology & Telecoms
ISTAT	Italy’s Office of National Statistics
LO	Licence Obligation
MAIFI	Momentary Average Interruption Frequency Index
MASE	Ministero dell’Ambiente e della Sicureza Energética
NGET	National Grid Electricity Transmission (TSO in GB)
NIA	Network Innovation Allowance
NRA	National Regulatory Authority
NVE-RME	Norges vassdrags- og energidirektorat - Reguleringsmyndigheten for energi (Norwegian NRA)
OBR	Office of Budget Responsibility
ODI	Output Delivery Incentives
Ofgem	Office of Gas and Electricity Markets (GB NRA)
OPEX	Operating expenses
OLS	Ordinary Least Squares
PCD	Price Control Deliverable
RAB	Regulatory Asset Base
RAV	Regulatory Asset Value
RES	Renewable Energy Sources
RIIO	Revenues using Incentives to deliver Innovation + Outputs
RoA	Return on Assets
RIIO	Revenues using Incentives to deliver Innovation + Outputs
ROSS	Regolazione per Obiettivi di Spesa e di Servizio
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SIF	Strategic Innovation Fund
TIM	TOTEX Incentive Mechanism
TOTEX	Total expenses
TSO	Transmission System Operator
UM	Uncertainty Mechanism
UIOLI	Use it or lose it
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

1 EXECUTIVE SUMMARY

The Netherlands is faced with the challenge of reaching carbon neutrality by 2050. This challenge requires substantial efforts from network operators and has prompted the energy regulator ACM to take a critical look at the way it organizes the regulation of network operators. It is important to obtain, at an early stage, an accurate picture of both, the bottlenecks and the opportunities with regard to the energy transition, arising from the regulation of network operators. In this regard, insights into the regulation of network operators in other European countries can be of great value. ACM has commissioned DNV Energy Systems (“DNV”) to obtain the insights.

The purpose of the study is to gather inspiration for instruments and new insights which could be considered in the Netherlands.

This is done by reviewing the main characteristics and effectiveness of the instruments used in the economic regulation of electricity transmission and distribution networks in selected countries. The list of countries is Belgium, Germany, Finland, Italy and Great Britain (main sample); and Norway, Australia and Emirate of Abu Dhabi (United Arab Emirates) (extended sample). Building on the findings from the analysis, we assess the applicability of regulatory instruments for the regulatory arrangements in the Netherlands.

Main Findings and Analysis of the Effectiveness

The analysis reviews major properties of the regulatory instruments in the investigated countries. The instruments are grouped in the following regulatory areas: price regulation methods, OPEX and CAPEX classification, assessment methods, efficiency incentives, investment incentives, innovation incentives, supplementary incentives, forward-looking estimations, dealing with uncertainty and new thinking / new concepts.

Price regulation methods

In all the investigated countries, the electricity transmission and distribution network operators are regulated using revenue caps. Under revenue cap regulation, the annual revenues that the regulated companies can earn are set in advance for the duration of the regulatory period. Furthermore, allowed revenues are typically adjusted for efficiency improvement targets and inflation. While there are differences between the studied regulatory systems, the allowed revenues set by the national regulatory authority (NRA) covers the efficient operating costs (OPEX) and capital costs (i.e., depreciation and return on assets). The return on assets is calculated as a product of the allowed rate of return (WACC) and the regulatory asset base (RAB).

Efficiency incentives

The regulatory frameworks in the investigated countries are based on incentive regulation, which seeks to encourage regulated companies to increase cost efficiency, undertake efficient investments and maintain or improve quality of supply. The incentive to reduce costs is provided by the NRA by setting the allowed revenues equal to the expected efficient costs and decoupling these from actual costs.

NRAs make use of efficiency analysis to estimate the efficiency of network operators and set efficiency improvement targets. In Germany and Norway, the NRAs have been successfully applying benchmarking to assess the efficiency of the network operators over many years. The German NRA evaluated the performance of the incentive regulation regime after the first two regulatory periods and observed an improvement in the network operators' efficiency score. The model specification and configuration have been regularly adapted and improved over time.

Some NRAs use sharing mechanisms to attribute efficiency gains (or losses) between network operators and network users. The sharing mechanisms can be applied to OPEX, CAPEX or TOTEX. Network operators that are able to achieve efficiency gains can retain those during the regulatory period. Incentives for efficiency improvements increase with the length of the period over which the network operator can maintain the efficiency gains (in case the company outperforms the efficient cost level).

At the end of the regulatory period, the costs incurred by the network operators may be reviewed (ex-post) for the purpose of setting the price control for the new regulatory period. Depending on the design of the regulatory framework, the efficiency gains may be carried over to the next regulatory period (efficiency carry over mechanisms).

Great Britain and Australia apply sharing mechanisms to also mitigate the information asymmetry between the NRA and network operators. The Australian NRA is also placing a strong emphasis on encouraging better forecasting of the network operators. It found that the level of information asymmetry has been reduced over time as the NRA progressively understands better how each company operates in practice.

Investment incentives

The energy transition causes a large need for investment in electricity transmission and distribution networks. Regulatory instruments are of central importance to ensure efficient and sufficient investments. Various instruments to assess investments are applied. These include ex-ante CAPEX reviews, explicit CAPEX allowances, ex-post CAPEX reviews, specific ex-post project reviews, ex-post total cost benchmarking, WACC mark-ups and CAPEX sharing mechanisms.

Investments can be integrated ex-ante or ex-post in the regulatory asset base (RAB). In the first case the NRA agrees on the capital expenditures allowed to be included in the RAB before the start of the regulatory period. This approach is used in Australia and Great Britain.

In combination with the ex-ante CAPEX review, an ex-post CAPEX review assesses the actual expenditure of the network operators at the end of the regulatory period. Ex-post CAPEX reviews are conducted by NRAs in Australia and Abu Dhabi (United Arab Emirates). NRAs may also choose to apply specific ex-post reviews to particular projects, typically "large" investments.

The German NRA does not develop an ex-ante opinion on whether a given investment should be allowed or not. Rather, the NRA examines the efficiency of the actual (historic) total costs incurred by the network operator by using ex-post total cost benchmarking analysis based on a national comparison of distribution network operators. This means that investment decisions remain with the network operator to conduct efficient investments. The threat that a company may look inefficient in the benchmarking assessment provides an incentive to the company to focus on undertaking efficient investments. A specific ex-ante CAPEX allowances was however introduced to counteract the delay between the time of capital expenditures and the time of the inclusion of capital costs in the allowed revenues.

The WACC mark-up is also a regulatory instrument for encouraging investments. It allows to add an explicit premium to the WACC set by the NRA.

The CAPEX sharing mechanism attributes the CAPEX efficiency gains and losses (resulting from differences between allowed and actual CAPEX) between the network operator and network users. For example, in Australia a Capital Expenditure Sharing Scheme (CESS) is applied. Based on the data collected since the introduction of the CESS, the Australian NRA found that the CESS has worked reasonably well and encouraged the network operators to invest efficiently. Furthermore, the network operators' underspending relative to the forecasts of the NRA has reduced significantly over time. According to the Australian NRA this demonstrates the improvement of the assessment methods (ex-ante reviews) over time.

Innovation incentives

With the rise of decarbonisation as a key policy goal, NRAs are recognising the need to adapt the regulatory framework to facilitate and encourage innovation and R&D in electricity networks.

In Great Britain, two explicit instruments are implemented to support innovation – namely the Network Innovation Allowance (NIA) and the Strategic Innovation Fund (SIF). The former focuses on projects to tackle challenges associated with delivering net zero GHG emissions. The latter is meant for high-value innovation projects (over £5m).

The NRAs in Norway and Finland apply an explicit R&D allowance based on a percentage of the allowed revenue. The Italian NRA allows to add an explicit premium to the regulatory WACC for innovation projects.

Supplementary incentive schemes

In addition to the classic cost reduction incentives, regulatory frameworks can set out supplementary incentive schemes. These include incentives for network loss reduction, quality of supply, targeted investment, achieving environmental objectives and producing good quality business plans.

The network loss incentive as applied in Germany and Italy allows the network operator to be rewarded (or penalised) whenever losses are below (or above) the target level. The network loss incentive applied in Italy proved to be effective in progressively reducing network losses over the years.

NRAs in all investigated countries use explicit incentives to maintain or improve quality levels. Under quality incentive schemes the company's actual performance is compared to quality targets for selected reliability indicators that measure continuity of supply. The quality incentive schemes have also been effective. For example, in Italy the application of regulatory quality incentives for more than 20 years resulted in an overall quality improvement and in a reduction of the differences in quality performance between the Southern and Northern regions. Other countries like Great Britain, Australia and Germany also showed reliability improvements due to quality of supply incentive schemes.

Furthermore, NRAs have been implementing targeted investment incentives on transmission interconnection capacity (Italy) and to encourage efforts towards market integration and enhancement of security of supply (Belgium).

The NRA in Great Britain applies a business plan incentive to encourage the network operators to submit high-quality and robust business plans. According to the NRA the business plan incentive was successful in encouraging network operators to submit good quality business plans which demonstrate strong stakeholder engagement.

Forward-looking estimations

To set the allowed revenue for regulated network services, NRAs need to determine projections of efficient OPEX and CAPEX for the following regulatory period. The cost projections can be based on historical costs and adjusted to account for future conditions (indexation). This approach has been applied in Finland and Germany.

Alternatively, cost projections may be set by using explicit forward-looking forecasts. NRAs in Great Britain and Australia have been using forward-looking approaches to assess ex-ante the allowed revenues of the network operators. The main challenge is to avoid inflated cost projections (OPEX and CAPEX) by the network operators. NRAs therefore apply various forms of analysis and assessment methods to counteract this. Some methods include time series analysis, comparative analysis, cost driver analysis, replacement cost analysis and project specific CBA / technical reviews. Depending on the approach applied, a combination of methods is applied. For example, drivers, such as demand, peak load and the number of connected customers is used as inputs for CAPEX forecast.

In terms of effectiveness, experience so far supports the notion that regulatory systems that set the allowed revenues using forward-looking estimations together with assessment methods and carefully calibrated incentives can encourage investments, and also drive innovations.

Dealing with uncertainty

European network operators face uncertainty regarding future demand for electricity and natural gas, future network capacity needs and efficiency improvements and penetration of new technologies. In such an uncertain environment, there is a risk pertaining to the deviation of efficient costs from the allowed revenue trajectories leading to financial surpluses or shortfalls to the network operators. In addition, there is asymmetric information between NRAs and network operators about firms' cost opportunities and managerial effort. There are different regulatory mechanisms that NRAs use to manage uncertainties. The most relevant ones include revenue adjustment schemes; interim reviews (or re-openers); trigger mechanisms; indexation/quantity adjustment factors; cost pass-through and menus of regulatory options.

These regulatory instruments are effective tools to accommodate unforeseen changes and developments, especially with respect to the energy transition and meeting decarbonisation goals.

New thinking / new concepts

There is a new trend in regulation of electricity network operators towards creating value for society, instead of focusing exclusively on the provision of network services. Several innovative instruments have been used to facilitate the energy transition by encouraging efficient investments and better sector coordination. Selected examples include incentives for controlling and prioritising investments (applied in France), end-of-life incentives (applied in Spain and Portugal), incentives for data provision (applied in France), incentives for the achievement of targets for electricity generated from renewable sources (applied in Ireland), stakeholder engagement incentive mechanism (applied in Ireland) and joint incentives (applied in Ireland).

According to the NRA in Portugal, the end-of-life incentive was effective in avoiding a direct link between the level of allowed revenues and the level of investment. As a result, investment decisions are made while considering technical and economic criteria for investment, operation, and management of the infrastructure.

According to the evaluation performed on the stakeholder engagement incentive mechanism in Ireland, the process worked well, and the network operators received and implemented recommendations for improvements provided by the evaluation panel.

For the other instruments, as these are relatively new, there is limited data on their effectiveness.

Applicability

Building on the findings from the international analysis, the study assesses the usefulness of the regulatory instruments and the associated options for the regulatory arrangements in the Netherlands. The assessment is based on four criteria: economic properties of the instrument, technical complexity, compatibility and implementation effort. Details of applicability are addressed in chapter 4.

The first criterion summarises the economic properties of the regulatory instrument relevant for the regulatory areas (purpose / nature and types of incentives / parameters). The second criterion addresses the technical complexity of the regulatory instrument in terms of analytical features, required modelling expertise and competencies, and data requirements. The third criterion examines the compatibility of the regulatory instruments with the arrangements in the current Dutch regulatory system. The last criterion deals with the administrative burden and the amount of effort required to fit the instrument in the current system.

The technical complexity of the examined regulatory instruments varies. There are instruments with a low complexity, for example WACC mark-ups or data provision incentives. Other instruments, such as sharing schemes, innovation allowances or loss incentive schemes exhibit a medium technical complexity. Finally, the use of instruments such as CAPEX reviews, efficiency analysis or menu regulation is characterised by a high complexity. The application of all the investigated instruments appears compatible with the current design of electricity transmission regulation in the Netherlands. Nevertheless, the degree of complexity and implementation efforts vary depending on the regulatory instrument.

In contrast, the application of several instruments such as sharing schemes, CAPEX reviews and business plan incentives are not compatible with the existing arrangements for electricity distribution and would require substantial changes in the regulatory framework. The conceptual design of the current yardstick system does not rely on a separate CAPEX analysis and submission of business plans. Furthermore, in the yardstick system a DSO which operates inefficiently relative to the yardstick will incur solely the efficiency loss. Similarly, a DSO can retain the efficiency gain if it is more efficient than the yardstick.

Regulatory tools like the use of WACC mark-ups or changes in the duration of the regulatory period are simple and can be easily implemented in the electricity transmission and distribution regulation. The implementation of instruments with a higher complexity (for example CAPEX reviews, sharing arrangements or menu regulation) would require a significant increase in the level of data reporting and regulatory scrutiny. Therefore, demanding moderate to high implementation efforts.

There are instruments that are not complex in terms of design (business plan incentives or innovation incentives) but burdensome for implementation. For example, the preparation of business plans and regulatory reviews are associated with significant implementation efforts. Similarly, adopting innovation incentives would require additional regulatory scrutiny in order to assess whether an innovation project qualifies for funding. This is in terms of defining certain criteria for innovation projects in order to be eligible.

ACM is experienced with the application of several of the investigated instruments (for example CAPEX reviews for ex-post assessments, efficiency analysis and quality incentives). However, the implementation of new instruments (for example menu regulation) or the extension of existing instruments (for example the use of CAPEX reviews for ex-ante assessments) in terms of scope and methods can require considerable expertise that ACM might need to develop or/and obtain from a third party.

2 INTRODUCTION AND PROJECT OBJECTIVES

The Netherlands is faced with the challenge of reaching carbon neutrality by 2050. This challenge requires substantial efforts from network operators and has prompted the energy regulator ACM to take a critical look at the way it organizes the regulation of network operators.

It is important to obtain, at an early stage, an accurate picture of both the bottlenecks and the opportunities with regards to the energy transition, arising from the regulation of network operators. In this regard, insights into the regulation of network operators in other European countries can be of great value.

ACM has commissioned DNV Energy Systems ("DNV") to obtain those insights.

The goals of the study are as follows:

- Review of the main characteristics of the instruments used in the economic regulation of electricity transmission and distribution networks in selected countries. The list of countries includes Belgium, Germany, Finland, Italy and Great Britain (main sample); and Norway, Australia and Emirate of Abu Dhabi (extended sample).
- Assessment of the effectiveness of the regulatory instruments applied in the investigated countries.
- Assessment of the applicability of the explored regulatory instruments for the current situation in the Netherlands.

This report is structured as follows:

Chapter 3: Findings and Analysis of the Effectiveness

This chapter summarises the properties of the regulatory instruments applied in the respective regulatory regimes. It is structured into the following regulatory areas: price regulation methods, OPEX and CAPEX classification, assessment methods, efficiency incentives, investment incentives, innovation incentives, supplementary incentives, forward-looking estimations, dealing with uncertainty and new thinking / new concepts. For each of these regulatory areas, the conceptual background and the practical use from the main and extended country samples is provided. The effectiveness of the respective regulatory instruments is also investigated and summarised.

Chapter 4: Applicability

This chapter provides an assessment of the applicability of the respective regulatory instruments discussed in Chapter 2 in the Dutch regulatory system. The analysis is based on four criteria: economic properties of the instrument, technical complexity, compatibility and implementation effort. The analysis of the applicability is presented in tabular form.

The economic properties of the regulatory instruments are relevant for the regulatory areas (purpose / nature and types of incentives / parameters). Technical complexity is related to the regulatory instrument in terms of analytical features, required modelling expertise and competencies, and data requirements. The third criterion examines the compatibility of the regulatory instruments with the arrangements in the current Dutch regulatory system. Administrative burden is the effort needed to fit the instrument in the current system.

Chapters 5 to 9: Main Country Samples

These chapters provide an overview of the economic regulation applied in the main sample: Germany, Great Britain, Italy, Belgium and Finland. For each of the countries, a detailed overview of the regulatory framework comprising of the revenue setting, cost assessment methods, efficiency incentives, investment incentives, innovation incentives, role of forward-looking estimation and regulation and energy transition is provided.

Appendix A1-A3: Extended Country Samples

The appendices include a summary of the economic regulation in Norway, Australia and Emirate of Abu Dhabi (the extended sample).

Appendix B: Summary table

The summary table provides an overview of the regulatory areas and the respective regulatory instruments which are applied in the investigated countries and the effectiveness of the instruments.

3 FINDINGS AND ANALYSIS OF THE EFFECTIVENESS

This chapter summarises the properties of the regulatory instruments and the findings of the investigated regulatory regimes. It is structured in the following regulatory areas:

- Price Regulation Methods
- OPEX and CAPEX classification
- Assessment Methods
- Efficiency Incentives
- Investment Incentives
- Innovation Incentives
- Supplementary Incentives
- Forward-Looking Estimations
- Dealing with Uncertainty
- New Thinking / New Concepts

Each section describes the conceptual background and the practical use of the main and extended country samples. The effectiveness of the respective regulatory instruments applied is also investigated. When addressing the conceptual aspects, we also include findings from our review of additional relevant information sources. Specifically, we looked at the regulatory arrangements set out in legal documents such as laws, ordinances, licenses, rules and regulatory decisions. In addition, we studied relevant documents published by the NRAs including monitoring reports, reports on regulatory activities, regulatory proposals, consultation reports and reports on specific regulatory issues.

From the documents published by the NRAs, we also looked at how the components of the energy policy trilemma are addressed (explicitly or implicitly) in the regulatory framework of the studied countries. From our research we conclude that the criteria of affordability, security of supply and sustainability guide the NRAs' decisions related to the regulatory framework to promote the changes driven by the energy transition. Nevertheless, NRAs do not clearly state which aspect of the energy trilemma is their priority and how the trade-offs between each dimension of the energy trilemma shall be reconciled.

Furthermore, we reviewed selected sector reports, policy reports and reports of consulting companies that provide useful information and facts for the purposes of our project. Finally, the review also included selected seminal academic papers and papers on applied regulatory aspects. The information sources are listed in section 14 of this report.

3.1 Price Regulation Methods

There is a broad supply of literature on different methods of regulation. The most common methods include rate of return regulation, cap regulation and yardstick regulation.

Rate of Return Regulation (cost-plus)

Under the traditional rate-of-return regulation the costs incurred by the regulated network operators can be charged to the customers. As such, the allowed revenue is set equal to actual costs including operating and maintenance costs and depreciation plus an amount to provide a return on the capital invested. This regulation method is also known as "cost of service" or "cost-plus" regulation (with the allowed rate of return representing the "plus" element). The allowed revenue is generally set every year, or sometimes every two years.

This approach is considered easy to apply. It has nevertheless two, well-known disadvantages. First it provides no incentive for the company to operate efficiently or to improve efficiency, as the network operator knows it will be able to recover its costs fully. The network operator has no incentive to make costs savings as they would be immediately taken from the network operator and given to consumers in the form of lower prices. Second, it provides an incentive for the network operator to over-invest. For example, the network operator could invest more and more and earn a return on its larger (unnecessary) investment. As a result of this over investment, the network operator essentially earns a higher-than-normal return on assets. This feature of rate of return regulation is sometimes known as “gold-plating”. It can be difficult for the regulator to identify this over-investment as this would require inspecting frequently the investment plans, to prevent it from happening. This is called the Averch-Johnson effect (Averch, H., & Johnson, L.,1962).

Cap Regulation

Incentive regulation schemes based on revenue or price caps are alternatives to rate-of-return regulation (Liston,1993; Armstrong et al., 1995; Bernstein & Sappington, 1999; Crew & Kleindorfer, 2002; Joskow, 2008). These schemes put a strong emphasis on the use of incentives for regulated companies to operate more efficiently. The electricity networks in the investigated countries (main and extended sample) are regulated using revenue caps. Italy applies the cap only for OPEX while the CAPEX is largely passed through to the network users. Under revenue cap regulation, the annual revenues that the regulated companies can earn are set in advance for the duration of the regulatory period. The cap refers to the upper limit that is placed on the allowed revenue hence the term revenue cap. Furthermore, allowed revenues are typically adjusted for efficiency improvement targets and inflation. The inflation is measured by the percentage change of a representative price index (typically CPI or RPI).

While there are differences between the studied regulatory systems, it is possible to give a general overview to describe the regulatory revenue setting (see below).

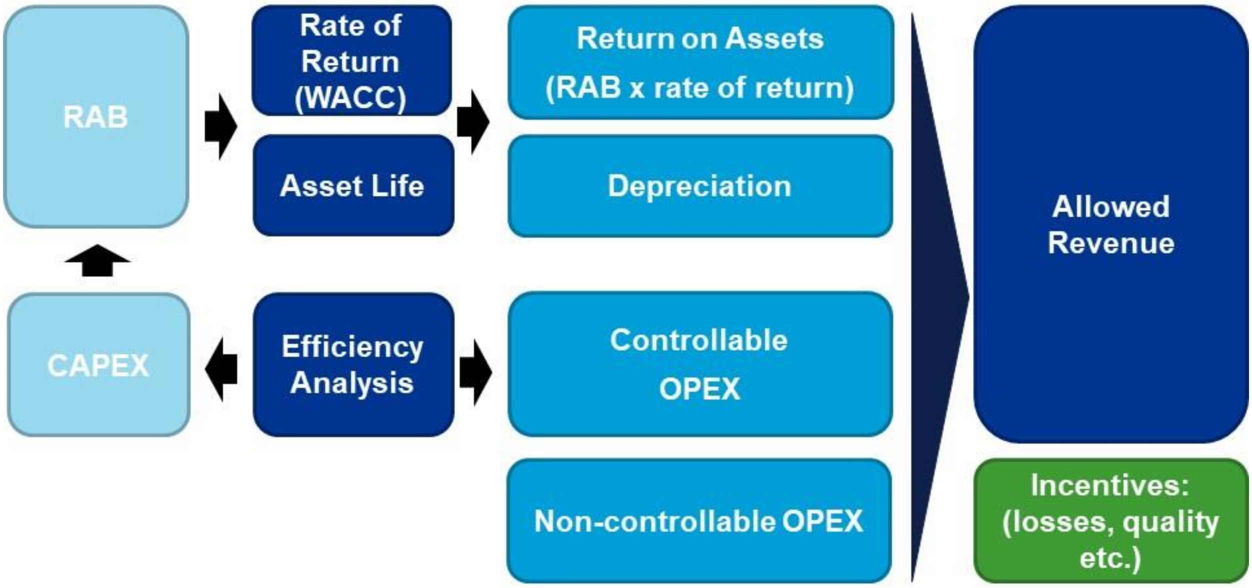

Figure 1: Simplified generic overview of the regulatory revenue setting

The figure illustrates how the allowed revenues are established. It covers the efficient operating costs (OPEX) and capital costs (i.e., depreciation and return on assets). The return on assets is calculated as a product of the allowed rate of return and the regulatory asset base (RAB). The rate of return is often calculated as the Weighted Average Cost of Capital (WACC) which consist of the equity return, debt return, and gearing used to establish the return on assets. OPEX is categorized into controllable and non-controllable OPEX. Non-controllable costs are passed through directly to network users as they are deemed to be outside of the control of the network operator. In contrast, controllable costs are exposed to efficiency analysis and network operators receive an ex-ante allowance representing the regulatory estimate of the efficient cost level. In addition, the figure includes incentives, depending on the regulatory regimes this can be incentives for losses, quality of supply for example.

The NRAs in the investigated countries set the asset life over which investments are depreciated.

The allowed revenues are not equivalent to the network operator's actual incurred costs but rather to the cost level that the NRA considers efficient. The difference between the actual costs before the start of the regulatory period and the estimated efficient costs is the anticipated efficiency improvement. This efficiency incentive enables the network users to benefit from lower network tariffs, while the network operators also benefit if they manage to reduce their costs below the regulatory estimate of efficient costs. The residual cost savings (efficiency gains) can be (fully or partially) retained in the form of higher profits at least during the current regulatory period.

There are two main ways of setting the cap:

- Building blocks approach: the regulator first assesses the maximum allowed revenues of the network operator for each year of the regulatory period by assessing separately the components of the allowed revenues, e.g., the planned OPEX, the planned CAPEX, depreciation, regulated asset base (RAB) and the rate of return (to calculate the return on assets). The next step is to convert this to a starting value of the allowed revenues for the first year of the regulatory period that is adjusted each year by an X-factor and inflation.
- TOTEX approach: the regulator would provide an overall total expenditure (TOTEX) allowance rather than individual CAPEX and OPEX allowances, based on the sum of CAPEX and OPEX. The regulator does not consider OPEX and CAPEX forecasts separately on a year-by-year basis.

The allowed revenues can be based on explicit forward-looking forecasts of the efficient costs, i.e., estimations of efficient costs that do not rely on historical costs. This is also referred to as linked caps. The linked caps serve to link revenues to explicit cost projections, allowing to align the allowed CAPEX and OPEX with the investment and maintenance needs in the near future adequately. Linked caps are traditionally applied in Great Britain and Australia. In Great Britain the TOTEX approach has been applied since 2013 for electricity transmission and in 2015 for electricity distribution.

Alternatively, allowed revenues can be set by taking the company's historic costs before the start of the regulatory period and adjusting them with exogenous drivers for inflation, efficiency and output changes. This can be referred to as unlinked caps. For example, Germany has used unlinked caps for electricity distribution for establishing the allowed revenues. Future revenue allowances are based on benchmarked historical costs, with no business plan (forecasts) by the companies. This is derived from the actual total costs (efficient operating and capital costs) of the network operator, taken from the three years prior to the start of the regulatory period (T-3).[1] Since the third regulatory period (2019-2023), the NRA introduced an explicit CAPEX allowance (Capital cost adjustment factor) to reflect the capital costs of planned investments in allowed revenues during a regulatory period (see section 5.5.2).

[1] Separate concepts of OPEX and CAPEX are recognised but allowed revenues are determined on the basis of total costs.

Elements of unlinked caps are also used in the Norwegian regulation of electricity distribution where 60% of the allowed revenues is set using efficient costs (cost norm) and the remaining 40% using historical costs.

In determining the efficient costs, the NRAs employ a range of assessment methods. These methods are presented in chapter 3.3. Furthermore, the NRAs also implemented explicit incentives to achieve particular outcomes or objectives. These pertain to for example maintaining the quality of supply, reducing costs of network losses or stimulating innovation projects (see sections 3.6 and 3.7).

Yardstick Regulation

Under this approach prices or revenues are indexed to an average of industry performance. Yardstick regulation is not based on an assessment of the cost position of individual companies but upon a comparison of prices or cost positions between the companies. Under a "yardstick" mechanism, companies are not allowed to charge higher prices than the mean price that is calculated based on all regulated companies in the sample, unless a different price was justified by their "special operating conditions". This form of price control was suggested by Shleifer, A. (1985). Whereby, in a group of comparable regional monopolists, the price cap is determined by the average costs of the others in the group. The advantage of this method is that it provides an incentive to operate better than the yardstick as this would generate profits. In turn, the more efficient operation will bring down the yardstick and will hence lower prices to end-customers in the longer term. This effect is very similar to the dynamics of competitive forces. However, problems with the practical implementation of yardstick regulation include that it can only be applied to services where there are enough comparative firms whose data can be used to form the yardstick. Furthermore, in general firms are inherently different because of factors they cannot always control, and firms rarely start from the same efficiency position.

3.2 OPEX and CAPEX Classification

The two main categories used in the regulatory revenue setting are operating expenditures (OPEX) and capital expenditures (CAPEX).

OPEX are the costs incurred by network operators to maintain and operate network assets and are associated with the conducting of the regulated activity. OPEX items can be classified as either controllable or non-controllable. Non-controllable OPEX are cost items which are outside the control of network operators such as regulatory fees, licence fees or costs associated with legislative requirements. Controllable OPEX are cost items which are under the control of the network operators, these typically include the costs of personnel, maintenance, and overheads such as buildings and office rentals, administration, etc.

When applying efficiency requirements on OPEX it is important that the efficiency targets are only set for those OPEX cost items that can be influenced (controlled) by the network operator. The classification of controllability is applied by all NRAs in the investigated countries

CAPEX can be categorised into:

- Load-related CAPEX
- Non-load related CAPEX / replacement

The main difference between these two categories is that load-related CAPEX is, as the name suggests, related to cases where the investments are driven by the additional load. Thus, load-related CAPEX is primarily linked to the connection of new customers and network reinforcement. Non-load-related CAPEX consists principally of investments in quality of supply and can roughly be divided into two categories: replacement expenditures (i.e., replacing old or malfunctioning equipment by new one) and investments that explicitly target improving quality levels (for example installation of telecontrol, improved protection).

In practice, it may be difficult to differentiate between replacement expenditures and “pure” load-related investments. For example, an older transformer may be replaced with new one but with higher capacity – anticipating future demand growth. Such investments, therefore, have mixed load and non-load related features.

In Great Britain and Australia, the distinction between load and non-load CAPEX is applied. Depending on the regulatory jurisdiction there can be differences in the categories of CAPEX. For example, CAPEX categories can be defined as expansion CAPEX or replacement CAPEX (REPEX).

3.2.1 Regulatory Cost Reporting

It is common that network operators are required to maintain separate accounts for their regulated activities. These accounts are often known as regulatory accounts and provide the NRA with financial information about that regulated activity. The scope of the reporting (i.e., the type of data and the level of detail required) reflects the purpose for which the NRA requires the information. This information may be needed for assessing OPEX for example.

For investments (CAPEX), the extent and level of detail of the reporting requirements usually depend on the scale of the planned investments. For example, in Great Britain, CAPEX is part of the business plans submitted by the network operators. The business plan includes the expected (forward-looking) investments for the upcoming regulatory period. In addition, network operators are required to include supporting information on the justification of the investments and cost-benefit analysis (CBA) as part of their regulatory submission. A similar approach is applied in Australia and Italy.

In Germany, regulatory reporting is used to establish the initial levels of the revenue cap for each network operator and separate the non-controllable costs. The information is applied for the efficiency analysis (benchmarking). The analysis uses the total costs (including both operating and capital costs excluding the non-controllable costs) of the network operators (see section 5.3.1 for details).

For the purposes of the assessment, different methods can be applied as explained in the following section.

3.3 Assessment Methods

There is a range of methods that NRAs use to assess cost efficiency for the purposes of revenue setting. These can be classified into two main categories: top-down methods and bottom-up methods.

These methods can be applied to the assessment of OPEX, CAPEX and total expenditures (TOTEX).

3.3.1 Top-Down Methods

The top-down methods estimate a network operator’s efficient costs by a comparison with other network operators (benchmarking). Benchmarking in a broad sense is a comparison of some measure of actual performance against a reference performance (Jamasb, T. & Pollitt, M., 2000). Benchmarking methods range from simple ratio analyses to complex multi-dimensional techniques (applied in Great Britain, Norway, and Germany) based on parametric analyses (corrected ordinary least square (COLS), stochastic frontier analysis (SFA) and/or non-parametric analyses – data envelopment analysis (DEA)) (Agrell, P. & Bogetoft P., 2016; Pollitt, M., & Nillesen P., 2010). The simplest approach for efficiency analysis is to use partial measures (performance indicators) to reflect output relative to a single input. With ratio analysis, such uni-dimensional ratios can be calculated by a comparison of single performance indicators between firms or by a comparison of the development of such indicators for a single company over time. Examples of typical ratios include labor costs/ GWh, OPEX/GWh, OPEX/network length etc. The drawback of this approach is that it does not consider the completeness of the process of the investigated companies but rather focuses on partial coefficients. In the regulatory practices they have been used to provide supplementary information.

DEA is a non-parametric method and identifies the efficient frontier using a linear programming technique. It benchmarks an individual network operator in relation to the best-practice (most efficient) companies. In DEA, the relative efficiency of a firm is computed (rather than estimated) on a scale of 0 to 1, where 1 means that it is at the efficient frontier. A company uses certain inputs to produce certain outputs. As multiple inputs and outputs are involved, to obtain a single measure that represents the efficiency of the input to output transformation process, some system of aggregation of input to output ratios is necessary. Data Envelopment Analysis (DEA) achieves this through a linear optimization seeking to envelop efficient companies into a so-called “efficiency (best practice) frontier”.

COLS and SFA are (parametric) econometric techniques that estimate the efficiency score of a firm relative to an efficient frontier. Both techniques require the specification of a cost function. Similar to DEA, the COLS technique labels all deviations from the frontier as inefficient. The efficiency scores calculated using COLS are therefore sensitive to the position of the frontier firms. SFA recognises the possibility of stochastic errors in the measurement of inefficiencies. SFA requires a large sample size to be able to obtain statistically significant results.

The main advantage of DEA is that it can accommodate multiple outputs and inputs, while COLS and SFA generally use a single input. In addition, DEA does not require a cost function to be specified, which avoids issues with cost function specification found in other methods. However, DEA is a non-parametric method, thus attributes all the deviations from the frontier to the inefficiency of the network operator and cannot account for noise or measurement error in the data. COLS is based on econometric theory and many statistical tests can be applied to examine the robustness of the results. As COLS is a parametric method and requires the definition of the mathematical specification of the estimated function. COLS like DEA cannot directly control for the presence of measurement errors or noise in the data. SFA is also an econometric technique, but it can decompose the residual term into inefficiency and noise (i.e., random error). For SFA to produce robust results, the dataset needs to be quite large, and it requires an assumption on the distribution of the inefficiency term.

The benchmarking methods (e.g., DEA, COLS, SFA) are widely applied in practice and are a useful and effective tool to estimate the efficiency of the network operators. They have been used over many regulatory periods. There have however been changes to the configuration of the model specification used for benchmarking. This has been improved over time as more experience was gained.

NRAs can also examine a network operator’s historical costs (trend analysis). For example, in Great Britain, the NRA has compared costs incurred during the previous regulatory period (RIIO-1) with proposed spending during RIIO-2 as part of its cost assessment. An advantage of looking at historic performance is that it considers implicitly the operating characteristics of the network operator in question. Historic performance might not provide an accurate guide to future performance however, especially if the operating environment and technology change or if network operators faced lower incentives to improve efficiency in the past. Nevertheless, this method is useful as a supplementary instrument as part of the overall assessment and is applied in practice (Great Britain, Australia). It can simply provide an indication to the NRA to request additional information where there are certain anomalies / outliers between the years.

3.3.2 Bottom-Up Methods

Bottom-up methods seek to identify the impact of cost drivers on individual cost items to determine efficiency performance. Bottom-up checks consist of splitting network companies´ costs by item and then assessing these items individually. The scrutiny of the assessment can range from an engineering/technical analysis needed for CAPEX assessment to a detailed review of certain cost items under OPEX. The detailed review of cost items can be based on a comparison of individual cost items among different network operators, the development of cost items over time, or the comparison of cost items with general industry trends or market prices. A bottom-up analysis can lead to a precise and detailed assessment of the efficiency of specific individual cost items. However, this approach may require significant resources and result in high administration costs. It is therefore important to assess the scope of potential and realistic efficiency improvements for different cost categories when deciding on the level of detail of the bottom-up analysis.

Bottom-up analyses can also be applied to assess business processes and activities or individual projects. For bottom-up analyses one can use engineering/technical reviews, or reference network models (have been used for electricity distribution in Chile). In the case of regulatory reviews of individual projects, Cost Benefit Analysis (CBA) can be used to assess the economic feasibility of the respective project. Australia applies CBA as part of its regulatory investment test (RiT) for larger investments. In Great Britain, engineering / technical reviews are applied to assess CAPEX.

Where external data is available, bottom-up analyses can be supported by comparisons (which are generally elements of top-down approach) of individual cost items with those of other network operators, actual historical levels, general industry trends or market prices. Standard unit cost analysis assigns unit prices for different types of equipment (asset groups) such as overhead and cable lines (EUR/km) and substations (EUR/unit). These values may be subject to further correction factors and should regularly be updated to reflect market conditions. The unit cost analysis can help NRAs examine if those investments are efficiently forecasted. In Finland, unit cost analysis is applied as part of the CAPEX incentive (see section 9.5).

Examples of bottom-up analysis are also applied in Great Britain and Australia (please see section 6.3.2 and appendix A2). In Great Britain, the NRA applied a combination of top-down and bottom-up methods to assess OPEX cost categories on activity level analysis.[2] Furthermore, for individual project reviews, technical / engineering reviews, and CBA are applied for CAPEX.

Similar to the top-down approach, bottom-up approaches are widely applied in practice and have been developed and improved over time. They are effective to support the NRA's assessment of efficiency improvements. Different methods are applied depending on the level of assessment. For example, CBA is applied for a more detailed assessment of specific projects supported by advisors.

3.3.3 Data Requirements

Both top-down and bottom-up methods can be applied to the subcategories of OPEX and CAPEX. Alternatively, an aggregated (combined) approach can be employed by assessing the cost blocks of OPEX, CAPEX or TOTEX in their entirety.

One of the reasons for this approach could be the required level of information and data to assess individual items, which may not be available for a robust analysis. By abstracting from individual cost items, a combined (aggregated) approach can help to avoid issues arising from the complexity of the cost boundaries, like differences in cost data reporting or activity definitions. Further reasons to group activities and expenditures in the assessment process relate to the complementarity

2 For example, a bottom-up approach to assess the subcategories of Indirect OPEX category which comprises of Business Support costs (BSC) and Closely Associated Indirect costs (CAI) is applied.

and trade-offs between OPEX and CAPEX. If a network operator can make trade-offs in expenditures between OPEX and CAPEX (substitution), assessing those expenditures together can help avoid biased relative efficiency results or unintended managerial incentives. This has been a main reason for the NRAs in Germany, Norway and Great Britain to use TOTEX-based models in their cost assessments. The major advantage of the TOTEX approach is that it removes the incentives for suboptimal CAPEX or OPEX choices as it can capture the trade-off between operating expenditures and capital expenditures. In addition, the TOTEX approach removes the incentive for overcapitalisation.

In practice, the NRAs often use elements of both top-down and bottom-up methods. For instance, in Great Britain the allowed revenues are set using the forward-looking business plans of the companies and efficiency analyses of Ofgem. Ofgem uses a combined approach (TOTEX OLS regression) and disaggregated cost assessment (activity-level analysis), both based on comparative benchmarking (see section 6.3.2).

3.4 Efficiency Incentives

The regulatory frameworks in the investigated countries are based on incentive regulation. Incentive regulation seeks to encourage regulated companies to increase cost efficiency, undertake efficient investments and maintain or improve the quality of supply. The incentive to reduce costs is provided by the NRA by setting the allowed revenues equal to the expected efficient costs and decoupling these from actual costs. Network operators that are able to achieve efficiency gains can retain those during the regulatory period. At the end of the regulatory period, the costs may be reviewed (ex-post) for the purpose of setting the price control for the new regulatory period. Depending on the design of the regulatory framework, the efficiency gains may be carried over to the next regulatory period. This is discussed in section 3.4.4. Customers benefit through lower prices in the medium and long term when the efficiency gains are passed through to the price level.

The NRA’s ex-post review can also be used to assess and understand whether cost savings (underspending) are for example not the result of deliberate investment deferrals. For overspending, the NRA may also recognise and reimburse these costs if the network operator can demonstrate and justify the reasons for this. This approach is applied where there is an ex-ante assessment of planned costs under the linked cap approach.

3.4.1 Efficiency Analysis

The purpose of efficiency analysis is to exploit the efficiency improvement potentials of network operators, to provide network operators with incentives to improve their efficiency performance and to ensure that consumers benefit from the efficiency gains.

Electricity networks use a wide range of inputs (capital, labour) to provide services to customers. While all network operators use broadly the same inputs, some may use proportionately more of some inputs and less of others. The mix of inputs used depends on management practices and the operating environment among other things.

NRAs make use of efficiency analysis (methods discussed in section 3.3) to estimate the efficiency of network operators and set efficiency improvement targets. These are basic inputs used in the configuration of regulatory incentives. The power of incentives depends on the efficiency target setting and the length of time during which the network operator can retain the efficiency gains. The next sections discuss the length of the regulatory period and how this can impact the efficiency gains, and the sharing- and carry-over efficiency mechanisms.

The German NRA evaluated the performance of the incentive regulation regime after two regulatory periods. It observed an improvement in the network operators' efficiency. Based on the efficiency assessment, the average efficiency of the electricity distribution network operators showed an increase from 92.2% to 94.7% from the first to the second regulatory period (BNetzA, 2015). For the current and third regulatory periods, the average efficiency score is 94.1%. This is derived from the average of the DSOs' efficiency scores from the efficiency analysis.

Since the first regulatory period, the model specification for the efficiency assessment has been further refined and developed with support from external advisers. The expert report conducted on behalf of the NRA sets out the methodology and the parameters to be applied for the efficiency assessment (Sumicid, Swiss Economics, 2019). The large number of distribution network operators in Germany allows for a national benchmarking assessment. Large efforts are required for the data collection and data validation process. Standardized cost reporting templates and guidelines are provided to the network operators, these too have been refined over time. For all regulatory periods to date, DEA and SFA techniques have been applied to determine the efficiency scores. This can be an indication that the German NRA is reasonably satisfied that this approach is effective for the purpose of price regulation.

Norway has been successfully applying total cost benchmarking of distribution network operators for several regulatory periods (see also section 3.5.2.2) for the purpose of assessing efficiency. Based on data from 2004 to 2014, Roar Amundsveen and Hilde Marit Kvile (Amundsveen, R.& Kvile, H. M., 2017) analysed the development in productivity for Norwegian electricity network operators and found that there has been a growth in productivity. The authors observed that incentive schemes with strong incentives for efficiency have contributed to increased productivity.

In Great Britain, the NRA applies TOTEX benchmarking using regression analysis to assess ex-ante the planned costs of the distribution network operators. This is in combination with other assessment methods (see sections 6.3.2 and 6.4.1). The NRA has continued to apply this approach for the current regulatory period.

3.4.2 Length of the Regulatory Period

Incentives for efficiency improvements increase with the length of the period over which the network operator can maintain the efficiency gains (in case the company outperforms the efficient cost level). A longer regulatory period allows the network operators to retain the benefit of any cost reductions and provides stronger incentives to improve efficiency. Conversely, if the regulatory period is short, incentives for cost savings are weakened and the network operators have less time to adapt and improve. However, longer regulatory periods may reduce the possibility for the regulator to respond to uncertainty when there is a persistent divergence between actual costs and the allowed costs.

In practice, the length of the regulatory periods is set by the NRAs to allow the network operators to achieve efficiency savings, while keeping some alignment of actual and expected costs. The NRAs in Germany and Australia are using regulatory periods of 5 years, Belgium and Finland have a 4-year regulatory period, while Great Britain and Italy use lengths of 8 years in their most recent regulatory periods. [3] The NRA in Italy decided for longer regulatory periods "*in order to create conditions of greater predictability and stability, with benefits in terms of improving the efficiency of the service*" (ARERA, 2019a). This option has been accompanied by reviews of relevant parameters for regulatory purposes during the period. Similarly, the NRA in Great Britain extended the regulatory period from 5 to 8 years to provide more regulatory stability and encourage longer-term focus. In Abu Dhabi, the choice of a relatively shorter duration (4 years) for price controls is driven by uncertainties within the electricity sector relating to issues such as demand growth and CAPEX forecasting.

[3] Germany had considered to move from a 5-year regulatory period to a 2-year regulatory period. This was mentioned in the 2015 evaluation report of the German regulator. However, the German Regulator decided to maintain the 5-year regulatory period. The main reason is shortening a regulatory period would increase the pressure on the network operators to achieve its efficiency targets which was not deemed suitable.
Ofgem changed back to a 5-year regulatory period for RIIO-2. RIIO-2 started in 2021 for electricity transmission and 2023 for electricity distribution.

3.4.3 Sharing Mechanisms

NRAs use sharing mechanisms to divide the efficiency gains/losses between network operators and network users. These can be applied for efficiency gains / losses in OPEX, CAPEX or TOTEX. In terms of design the mechanisms can also include a maximum and minimum level (cap or floor) above or below which no sharing applies, and gains/losses remain with the network operators or network users respectively. Sharing mechanisms can also be applied for specific cost items such as cost of network losses (section 3.7.1) or quality of supply (section 3.7.2).

Sharing mechanisms are based on a defined allowance. Due to the information asymmetry that exists between the NRA and the network operators, one of the challenges of the NRA is to ensure that an underspend is the result of genuine efficiency gains and not a result of forecast error.

Sharing mechanisms have been used by the NRA in Great Britain to mitigate the information asymmetry between the NRA and network operators. The TOTEX Incentive Mechanism (TIM) is designed to encourage the network operators to improve efficiency in the delivery of their business plans. The TIM – also known as the 'sharing factor' – determines the network operators' exposure to under- or overspends compared to the TOTEX allowances. It is calculated based on the difference between actual TOTEX and allowed TOTEX. The electricity TSO is exposed to 33% of any under- or overspend and the consumer is exposed to the remaining 67%. For electricity distribution, an individual TIM incentive rate is set for each distribution network operator. The TIM sharing factor ranges from 49.3%-50% for the distribution network operators.[4] For RIIO-1 (1 April 2013 to 31 March 2021) the transmission network operators reported a TOTEX underspend of close to £3.77 billion or 20% (Ofgem, 2022c).[5] This underspend is primarily driven by savings in both load-related and non-load -related spending, outweighing the overspend in the other cost categories. Current performance on TOTEX varies across distribution network operators with the majority underspending. Performance to date ranges from a 4% overspend to a 13% underspend (Ofgem, 2022a).

Australia also applies sharing mechanisms for CAPEX and OPEX respectively (see sections 3.5.4 and appendix A2). The Australian NRA is placing more emphasis to encourage better forecasting as part of its current review of its incentive schemes (AER, 2022e). It states that the level of information asymmetry between the NRA and the network operators has inevitably been reduced over time as they progressively understand better how each company operates in practice. With respect to the OPEX sharing scheme, the Australian NRA has reported that it has successfully driven OPEX efficiency gains as a result of the revealed cost OPEX forecasting approach and its approach to benchmarking.

The recent experiences from Australia and Great Britain show that the sharing mechanism is considered as a useful and effective tool to drive and improve efficiency by the respective NRAs.

3.4.4 Efficiency Carry-over Mechanisms

At the end of the regulatory period, the price control is reset for the next regulatory period. During the regulatory period, depending on the regulatory regime, a network operator is typically able to retain any efficiency gains if they have been able to perform efficiently. When preparing for the following regulatory period an NRA can determine to what extent these efficiency gains should be carried over to the next regulatory period. On the one hand, the greater the share of the benefits the regulated network business is allowed to retain in the subsequent regulatory periods, the greater their incentives will be to make efficiency savings, and the greater the extent of those savings which are eventually passed on to consumers.

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4 The exact proportion of the sharing mechanism depends on the respective regulatory framework. There is no predetermined "optimal" sharing of gains or losses.

5 Through the TIM sharing factor, customers will receive £2bn of the overall underspend, which will reduce customer charges; the TNOs will retain the remaining £1.77 bn

On the other hand, the greater the share the regulated network businesses are allowed to retain, the longer customers will have to wait before the benefits from efficiency savings are passed through to them.

The term “carry-over mechanism” describes the regulatory mechanism used to carry over all or part of any efficiency gains from one regulatory period to the next. It should provide sufficient incentives for the regulated business to pursue efficiency gains. That is, the benefit that the regulated company can retain should out-weigh the cost of the efficiency improvement. Efficiency carry-over can be considered as an extension of the sharing schemes.

Efficiency carry-over is used currently by the NRA in Italy where the network operators are allowed to carry over 50% of the OPEX efficiency gains from the base year into the next regulatory period. This is then gradually passed on to the network users (see section 7.3.1 for details).

In Australia, the OPEX sharing scheme allows the company to retain the benefits (or incur the costs) of outperforming (underperforming) relative to the forecast for 6 years. When the network operators undertake efficient expenditure, it is also used to forecast efficient operating expenditure in subsequent regulatory periods. The reason provided by the Australian NRA is that it removes incentives for the network operators to increase OPEX in the expected base year, by maintaining incentive levels throughout the regulatory period.[6] Without the carryover mechanism, the network operator would only retain the efficiency gains for the remainder of the regulatory period, resulting in declining rewards for cost reductions as the regulatory period progresses and low incentives in the final years. This could encourage deferring efficiency gains until early in the next regulatory period.

The carry-over mechanisms applied in Italy and Australia strengthen the incentive to improve ongoing efficiency, not just for the respective regulatory period but on a continuous basis. The OPEX sharing scheme applied in Australia shows to be effective as the network operators appear to have been operating efficiently (AER, Electricity network performance, 2022) and performing better when assessing the actual OPEX spend against the allowed OPEX. OPEX performance from 2006-2021 shows that in 2021, the distribution network operators together spent 6% less than allowed OPEX.

3.5 Investment Incentives

The energy transition causes a large need for investment in electricity transmission and distribution networks. This need for investment is triggered by several factors such as the need to connect and integrate distributed renewable generation and new demand sources (electrical vehicles, heating, etc.). If favourable sites for renewable generation are far away from the consumption regions, new electricity lines need to be constructed to connect the generation sites. Regulatory instruments are of central importance to ensure efficient and sufficient investments.

In the following sections, various instruments to assess investments are provided. These include ex-ante CAPEX review, explicit CAPEX allowance, ex-post CAPEX review, specific project review, ex-post total cost benchmarking, WACC markup and CAPEX sharing mechanisms.

3.5.1 Ex-ante CAPEX Review

Investments can be integrated ex-ante or ex-post in the regulatory asset base (RAB). In the first case the NRA agrees on the capital expenditures allowed to be included in the RAB before the start of the regulatory period. This is done in Australia and Great Britain under the building blocks approach. The companies submit information on their investment plans before the start of the regulatory period. They have the incentive to overestimate the reported planned capital expenditure and

6 This is because as part of the cost assessment of OPEX, the NRA starts with a single year of actual OPEX (the base year, typically year 4 of the regulatory period) to forecast future requirements.

achieve full recovery through the allowed revenues. The major challenge for the NRA is to judge which investments are efficient and sufficient to be recognised in the allowed revenues of the network operator. In order to support their assessment, NRAs make use of business plan submissions, comparative economic analysis (benchmarking), engineering expert reviews and cost-benefit analyses (CBA).

Before the start of a regulatory period, the Australian NRA assesses the companies' investment plans using a combination of technical and economic methods. Furthermore, certain projects are subject to Regulatory Investment Tests (see Appendix A2).

In Great Britain, the NRA also applies a combination of aggregated cost assessment and individual cost assessment (activity-level analysis), both based on comparative benchmarking (see section 6.3.2). The purpose of the ex-ante forward looking review is to assess and recognise the necessary CAPEX for the duration of the regulatory period. In this way the ex-ante CAPEX review provides the companies certainty and incentives to invest. Guidance and objectives are provided by the NRA on how to develop their business plans and decide on their investment needs. This is also supported by the Business Plan Incentive (BPI), which provides a financial reward or penalty depending on how the network operator's forecasts relate to the NRA's assessment of the submitted business plans (see section 6.7.1).

The possibility that companies are inflating their costs when submitting their CAPEX plans has always been a challenge due to information asymmetry. Furthermore, the assumptions and level of detail provided by the network operators to the NRA for them to conduct a review are also important. This was also evident in Abu Dhabi, when the NRA decided to introduce ex-ante CAPEX reviews for the regulatory period 2018-2022. The companies were not able to provide sufficient information and the NRA did not provide "*very detailed guidance*" and "*a suitably long implementation period*" to enable the companies to understand, implement and comply with an entirely new process. Given the companies' performance during the first ex-ante CAPEX review, the NRA decided to provide further flexibility by planning an interim ex-ante review in 2019 and, if necessary, resetting the ex-ante allowances for CAPEX.

Overall, the continued use of ex-ante reviews in Australia and Great Britain indicates that they have been considered effective. In these two countries, the NRAs have developed and improved their approaches to assessing CAPEX. Their approach, and methods for CAPEX assessment have been refined and improved further over time.

3.5.1.1 Explicit Ex-ante CAPEX Allowance

In some regulatory frameworks, the NRA does not conduct ex-ante CAPEX reviews but set the allowed revenues based on the total cost which includes investments already incurred. This approach gives the network operator autonomy in their investment decisions. See section 3.5.2.2. Therefore, any investments that the network operators conduct during the regulatory period are only recognised in the allowed revenues in the subsequent regulatory period. Explicit ex-ante CAPEX allowances aim to counteract the delay between the time of capital expenditures and the time of the inclusion of capital costs in the allowed revenues. This mechanism is applied where there is no explicit ex-ante CAPEX assessment when establishing the allowed revenues. For example, capital cost adjustment factor was introduced for electricity distribution in Germany in the third regulatory period. The purpose of this mechanism was to recognise and include the capital costs for new investments in the allowed revenue during the regulatory period without a time lag. Previously, any investments conducted by the network operator during a regulatory period were only recognised in the benchmarking assessment to establish the allowed revenues for the next regulatory period – hence the time lag. This mechanism was introduced to eliminate this time-lag and enable the recovery of the capital costs of investments during a regulatory period. The distribution network operators are required to submit a formal application to the NRA and the capital costs are subsequently included in the revenue cap based on the planned costs. Please see section 5.5.2 for details.

3.5.2 Ex-post CAPEX Review

In combination with the ex-ante CAPEX review, an ex-post CAPEX review assesses the actual expenditure of the network operators at the end of the regulatory period. The ex-ante approach may encourage the network operators to over claim for investments and then under-spend. Ex-ante reviews do not always provide the NRA with the necessary information to assess whether the network operator is planning its efficient investments.

Therefore, the ex-post CAPEX review allows the NRA to assess the efficiency of the actual expenditure incurred and prevent allowed but unused investment costs being rolled into the RAB. Ex-post CAPEX reviews can provide positive incentives to the companies to execute to their best of their ability the projects according to the approved plans.

The ex-post monitoring of the actual expenditure against its allowance (based on the ex-ante review) is beneficial for both consumers and network operators. The ex-post review not only protects consumers from paying for inefficient expenditures (any expenditures not demonstrated to have been efficiently incurred will be disallowed) but also protects network operators, by allowing costs above the ex-ante allowance (that have been proven to be efficiently incurred).

The ex-post review can be done according to CAPEX categories (e.g., load-related, non-load, replacement), for the total CAPEX as a whole, or on a project-specific basis (see section 3.5.2.1). This depends on the arrangement set out in the regulatory framework.

Until 2018, the assessment of CAPEX in Abu Dhabi was only based on an ex-post review of efficient CAPEX. Provisional CAPEX used in setting the allowed revenues was just to facilitate the financing of CAPEX and smoothing of the allowed revenue. Thus, CAPEX inefficiencies would be identified, and operators penalised only after some years from the initiation of CAPEX projects. To address this limitation, the NRA introduced forward-looking ex-ante approval to CAPEX assessments. Ex-ante approved projects would be subject to ex-post review if either the scope of work changes or if actual costs deviate from the ex-ante allowance by more than 10%.

In Australia, the NRA conducts ex-post CAPEX reviews. This also includes any decisions by the NRA to exclude certain types of CAPEX from the RAB. It reviews the deviation between the allowed planned and actual CAPEX. To support the ex-post reviews, the network operators are required to submit information to the NRA on the progress of the projects on an annual basis. At the end of the regulatory period the NRA determines the CAPEX that is to be rolled into the RAB.

The review is done in two stages. The first stage considers several factors including whether the network operator had overspent over the period, the size of any overspending, CAPEX history and how the network operator had performed relative to similar network operators. Based on this assessment, if there are no significant concerns about CAPEX performance, no further assessment of CAPEX efficiency would be required. However, based on the review in stage one, if the CAPEX performance indicates further assessment is needed, the assessment would progress to the second stage. In the second stage, a more detailed review is applied. This would entail an assessment of the processes that the network operator applied for asset and project management including a detailed review of the CAPEX spending. The conduction of ex-post reviews allows the NRA to disallow costs which are deemed inefficient but also allows additional costs to be considered if the network operator can demonstrate their justification.

The ex-ante CAPEX review conducted by the Australian NRA is a thorough process, and dedicated resources and expertise are required. The NRA also draws on the expertise of engineers and other external consultants to support this assessment. The network operators are also required to provide reporting of their CAPEX spending on an annual basis. This is of importance for the NRA to conduct the review effectively.

3.5.2.1 Specific Ex-Post Project Review

The NRA may choose to conduct ex-post CAPEX reviews for selected projects. These so-called specific ex-post project reviews are typically conducted for "large" investments such as those which were subject to ex-ante regulatory investment test (RiT) in Australia.[7] In the Netherlands, an ex-post review on a project-specific basis is also applied by the Dutch NRA (ACM) for projects made by the transmission system operator. The Dutch NRA does not conduct ex-ante CAPEX reviews.

The purpose of the specific project review is to assess the efficiency of the actual expenditure incurred for specific projects. If there was an ex-ante assessment for a specific project, then the review is similar to the ex-post review as described above (section 3.5.2). The NRA would compare actual CAPEX with allowed CAPEX for the specific project and seek to understand the differences.

For projects that did not undergo an ex-ante review (for example in the Netherlands), the NRA would assess the specific project on an ex-post basis. The purpose is to assess that the spending of the project has been efficient. In order to do so, the network operator would need to report the actual spending for the project and additional supporting information to the NRA. The NRA would be dependent on the information from the network operator in order for the review to be effective, therefore the regulatory framework would need to have the necessary provisions for information submission, and monitoring reporting needed for them to conduct ex-post project reviews.

3.5.2.2 Ex-post Total Cost Benchmarking

By using ex-post total cost benchmarking the ex-ante investment assessments for CAPEX can be effectively bypassed. The NRA may decide not to develop an ex-ante opinion on whether a given investment should be allowed or not. This may be particularly relevant when there is a large number of regulated companies, and an ex-ante CAPEX assessment may impose a large administrative burden on the regulator. Rather, the NRA examines the efficiency of the actual (historic) total costs incurred by the network operator by using a benchmarking analysis based on a national comparison of distribution network operators, as applied in Germany for example.

In Germany, the efficiency target for each regulatory period is determined based on ex-post total cost benchmarking. The efficiency increase requirements are set on the basis of performance achieved in previous years. The NRA does not conduct ex-ante CAPEX reviews, it leaves the investment decisions to the network operator to conduct efficient investments. The capital costs are therefore included as input in the benchmarking analysis. The threat that a company may look inefficient in the ex-post total cost benchmarking assessment provides an incentive for the company to focus on undertaking efficient investments. If a company manages to increase productivity, its efficiency score will be higher for the next regulatory period and consequently the required efficiency increase will be lower (see section 5.4.1). A further advantage of this approach is that it provides an incentive for the network operators to be indifferent to the mix of cost inputs (OPEX and CAPEX).

However, applying ex-post benchmarking to incurred investments could negatively influence investment incentives. The risk of cost disallowance arising from this approach could undermine incentives to invest and innovate. Also, with regulatory periods of five years or longer, solely relying on an ex-post analysis would lead to a significant amount of time between capital expenditures and RAB integration. Consequently, the stand-alone application of ex-post efficiency analysis may not be sufficient in reflecting the needs of network investments. For this reason, in practice, ex-post efficiency analysis is combined with additional instruments to support investments undertaken during a regulatory period. Take for example the use of capital cost adjustment factor in Germany (see section 3.5.1.1 and section 5.5.2).

Germany and Norway have been successfully applying an ex-post total cost benchmarking of distribution network operators for several regulatory periods. The benchmarking models use econometric and non-parametric techniques, and

7 Regulatory investment tests are for projects that exceed a certain value.

the total actual costs (capital and operating costs) are based on historical data. This data is used as the model input (see section 5.4.1).

In Norway, the NRA applies separate (DEA) benchmarking models for local and regional distribution network operators. In addition, the DEA results are adjusted using a second-stage regression analysis to account for the heterogeneity in the network operators operating environment. Moreover, the NRA has recently commissioned research (Rodseth et al., 2021) to investigate alternative methods for benchmarking of Norwegian electricity grid operators that are currently omitted from the DEA-yardstick competition framework because of their size or uniqueness.

If applied robustly, benchmarking is an effective tool for minimising the asymmetry of information between the regulator and the network operators. When benchmarking is feasible, the NRA would be able to compare network operators on their level of performance independently of the information provided by the network operator itself.

The effectiveness of adopting benchmarking depends mainly on:

- the definition of costs,
- cost drivers considered,
- sample of network operators,
- selected techniques/statistical models,
- consideration of differences in the operating environment and
- the way NRAs use the results of the benchmarking (i.e., how the efficiency scores are translated into cost allowances).

In the context of decarbonisation, there is uncertainty in the volume of new costs and the timing required to meet the targets. Therefore, there is a risk that the sole application of ex-post benchmarking would not provide reliable and informative results to set the allowed revenues for the upcoming regulatory period. Therefore, as mentioned above in practice ex-post efficiency analysis is combined with additional instruments to support investments.

Germany is a good example of the results of the application of ex-post total cost benchmarking. The approach has been consequently applied in all regulatory periods and efficiency improvements of the network operators are evident (see section 3.4.1). The model specification applied for the benchmarking has been adjusted over time. For distribution, the network operators whose efficiency scores less than 60 percent will receive a target floored at 60 percent. This offers a certain level of protection (safety net) in terms of their efficiency improvement target for the regulatory period.

3.5.3 WACC Mark-up

Given the capital-intensive nature of the regulated electricity networks, the return on asset accounts for significant share of the allowed revenue. As relatively small changes to the rate of return can have a significant impact on the total revenue requirement and investment behaviour of the network operators, it is important that the regulator sets the rate of return at a level that reflects a commercial return for the regulated businesses.

The weighted average cost of capital (WACC) methodology is a widely accepted method for calculating the cost of capital. It is understood by both the finance community and the industry and is consistent with the methodology used by many regulators. The WACC is determined as the weighted average of the cost of each individual component of the capital structure weighted by its share. The WACC formula may look different depending on how taxes and inflation are treated in the revenue requirements of respective regulatory regimes.

The WACC mark-up is also an option for supporting investments that can be applied by the NRA. Therefore, the WACC mark-up allows to add an explicit premium to the WACC set by the regulator. This adjusted WACC can be applied to specific investments, e.g., pre-defined strategic projects, innovation projects (see section 3.6) or others.

While in the short term, such a WACC mark-up is very effective in encouraging investments, in the middle- and long term it may provide a strong bias towards inefficient allocation of resources and overcapitalisation. Therefore, if an NRA opts for a premium on the allowed rate of return, it should limit its usage for a limited period. For example, at the end of 2015, the Italian NRA decided to gradually phase out the WACC mark-up (see section 7.6) as it decided to move from input-based regulation to more output-based regulation.

3.5.4 CAPEX Sharing Mechanisms

Dedicated CAPEX sharing mechanisms are similar to the sharing mechanisms as discussed in section 3.4.3 .The CAPEX sharing mechanism shares the CAPEX efficiency gains and losses (resulting from allowed and actual CAPEX) between the network operator and network users.

For example, in Australia a Capital Expenditure Sharing Scheme (CESS) is applied. The CESS provides the network operators with an incentive to undertake efficient CAPEX during a regulatory period. It achieves this by rewarding the network operators that outperform their CAPEX allowance and penalising those that spend more than their CAPEX allowance. Under the CESS, the current regulatory provisions allow a network operator to retain 30% of an underspend or overspend, while network users retain 70% of the underspend or overspend. The CESS was introduced in 2013. Prior to this, any CAPEX underspend during a regulatory control period meant the network operator would retain the benefits of financing the forecast CAPEX during the regulatory control period. Consumers would then benefit after the end of the period when the RAB was rolled forward to a lower amount than if the full amount of the CAPEX allowance had been spent. This would lead to lower regulated network prices in the future. However, under this approach, the benefits to a network operator of underspending become progressively less after each year during a regulatory control period. As the benefits of underspending are smaller as the regulatory control period progresses, the incentives for efficient CAPEX decline over the regulatory control period. This is one of the reasons for the introduction of the CESS (AER, 2013).

Since the introduction of the CESS, the data that the Australian NRA has collected thus far strongly suggests that the CESS has worked well to provide incentives for the network operators to incur efficient CAPEX. Furthermore, the network operators' underspending relative to the forecasts of the NRA has reduced significantly over time. The Australian NRA say this is a result of improved assessment methods (ex-ante review) over time.

For distribution network operators, the average underspend (has fallen from around 18% in the first regulatory period to around 7% in the current regulatory period. For transmission, an underspend of some 28% in the first regulatory period is now an overspend of around 5% (despite the transmission being more difficult to forecast because it is less recurrent and has more project 'lumpiness' with significant major projects) (AER, 2022e). The NRA attributes this as the result of the development of the regulatory tools used to assess and determine the network operators' CAPEX forecasts (see appendix A2). Nevertheless, the NRA is currently reviewing its incentive schemes including the CESS. The initial review is that there is cause to further improve forecast outcomes at the ex-ante stage. This is to avoid rewarding a company for an underspend as the ex-ante allowance was set inaccurately and therefore not the result of genuine efficiency gains.

3.6 Innovation Incentives

Incentive regulation was originally designed with the aim of improving the efficiency of natural monopoly infrastructures. The issue of innovation was often not dealt with explicitly in regulation, as it was assumed that the incentive for cost reduction also promotes innovation if such activities lead to long-term efficiency improvement (Jamasb & Pollitt, 2007). Strong emphasis on short-run cost efficiency can result in the reduction of technological innovation and hinder research and development needed to facilitate the energy transition. Therefore, with the rise of decarbonisation as a key policy goal, NRAs are recognising the need to adapt the regulatory framework to facilitate and encourage innovation and R&D in electricity networks. This is one of the underlying drivers for innovation needs to address energy transition goals to be an integral part of the regulatory provisions. Innovation incentives have been introduced in some countries to encourage companies to seek and explore innovation projects.

For the countries which have implemented regulatory tools for innovation funding, a common characteristic is that clear objectives and goals need to be defined beforehand indicating the type of projects that would fall under innovation. Furthermore, one of the main prerequisites for introducing innovation instruments is to allow network operators to address and explore in areas which they would not otherwise undertake.

In Great Britain, two explicit instruments are implemented to support innovation – namely the Network Innovation Allowance (NIA) and the Strategic Innovation Fund (SIF). The SIF is meant for high-value innovation projects (over £5m). The funding and the process to access the SIF is competition-based and a number of eligibility criteria must be met. There are also different project phases associated with SIF. The NIA focuses on projects to tackle challenges associated with delivering net zero greenhouse gas emissions. See sections 6.6 and 6.9.1 for details on these instruments.

To ensure that innovation funds are allocated properly, the network operators are required to submit innovation strategies as part of their business plans for the regulatory period (Ofgem, 2021a). Furthermore, annual innovation summary reports are published by each network operator. This report summarizes the activities and spending to date and any new findings related to the projects under the NIA.

The innovation instruments should state specific objectives and the network operator should demonstrate its intention on meeting these objectives through the innovation mechanism in order for funding to be approved. For example, in Great Britain, specific eligibility requirements must be met. These requirements state that the innovation project must facilitate energy system transition and/or benefit consumers in vulnerable situations (see section 6.6 for further details).

In Norway, an explicit innovation incentive is also applied from 2013. It sets an allowance for funding innovation and R&D initiatives. The R&D allowance is based on a percentage of the regulatory asset base. As of October 2021, the Norwegian NRA has approved 215 projects in the scheme. A generally increasing trend of innovation projects has been observed over the years (NVE-RME, 2022a). The network operators apply for the R&D allowance through a formal application process. The NRA has set out criteria that must be met with the network operators providing information about project goals. The NRA also specify the type of criteria that needs to be met in order to be eligible for R&D projects (NVE-RME, 2022b). The NRA also publishes a list of approved projects on their website.

The Italian NRA allows to add an explicit premium to the regulatory WACC for innovation projects. Furthermore, the WACC premium is also applied to certain types of investments including innovative solutions and technologies.

A regulatory instrument to support innovation recognised in the regulatory framework can be regarded as a positive development. For the innovation instruments to be effective, a common feature is that the process is transparent and clear guidance on eligibility and criteria is provided by the NRA.

3.7 Supplementary Incentive Schemes

In addition to the classic cost reduction incentives, regulatory frameworks can set out supplementary incentive schemes focusing on additional areas of performance such as network loss reduction and quality of supply. Furthermore, NRAs have been promoting initiatives and implementing explicit incentives on the network infrastructure to encourage market integration across Europe.

In the following an overview of supplementary incentive schemes is provided, based on the analysis of the regulatory regimes in the main and extended sample. These include incentives for network loss reduction, quality of supply, targeted investment, and achieving environmental objectives and business plans.

3.7.1 Incentive Schemes for Network Loss Reduction

A general definition of network losses is the kWh consumed by the network in moving power. This is measured as the difference between total energy metered into and metered out of the network over a given period. Network losses can be categorised into technical losses ("physical losses") and commercial losses ("non-technical losses").

European NRAs have been widely using incentive schemes to reduce the cost of network losses. Network operators are encouraged to reduce network losses through incentives based on their loss rate relative to a target. The incentive allows the network operator to be rewarded (or penalised) whenever losses are below (or above) the target level. The incentive schemes are based on physical loss targets set in absolute terms or as a percentage of the electricity volume delivered to the electricity networks. These targets can be determined using historical losses or standard losses. Historical network losses are actual losses whereas standard losses are estimated by the NRA (pre-set target level).

One advantage of such incentive schemes is that they allow the network operators to develop and decide on ways to reduce losses, making it likely that loss reductions will be achieved at minimum cost. Another advantage is that the mechanisms are reasonably transparent and not burdensome in terms of administration and compliance. Moreover, there is a direct environmental cost associated with network losses as technical losses are directly related to carbon emissions. Therefore, providing incentives to reduce losses can help to achieve carbon reductions. The adoption of incentive schemes for network loss reduction creates benefits for network users and for society. The reduction of network losses contributes to improving energy efficiency and reduces OPEX.

Italy and Germany apply explicit incentives for network losses by incorporating a separate cost allowance for network losses into the allowed revenue. In Germany, the revenue cap of the distribution network operators is adjusted annually to account for technical network losses. The adjustment is equal to the difference between the determined cost of network losses in the base year and the allowed cost of network losses in that year. Please see sections 5.4.2 and 7.4.2 for details.

In Great Britain, the NRA has used network loss incentive schemes in the past. It plans to reintroduce a direct financial incentive on losses once smart metering data is available (Ofgem, 2017).[8]

The effectiveness of incentive schemes for loss reduction depends mainly on the design of the incentives. For example, in Italy, an analysis of the results of the period 2015-2020 showed a progressive reduction in network losses over the years (ARERA, 2022c). Italy introduced a new regulation in 2016, which extended the use of standard loss factors to non-technical losses, it introduced measures for mitigating non-technical losses and differentiated standard losses on the basis of different operating conditions of the network.

8 From January 2022 suppliers will have binding annual installation targets to roll out smart and advanced meters to their remaining non-smart customers by the end of 2025.

3.7.2 Quality Regulation Incentive Schemes

Investment decisions have a significant impact on the network's quality. The ability to effectively account not only for cost efficiency, but also for quality is therefore an important regulatory task.

NRAs have developed different methods to encourage the quality of supply. The traditional method of quality regulation is based on quality performance standards. Standards put a floor on the performance level of the company measured by using selected quality indicators. Violation of a standard can lead to a fine or tariff rebate. Examples of quality performance indicators are customer minutes lost, percentage of customers with an outage or duration of an interruption.

NRAs can also use explicit incentives to maintain or improve quality levels. These incentive schemes are used in combination with efficiency incentives to ensure that a required efficiency increase is not at the expense of quality (as there is a trade-off between costs and quality). Under quality incentive schemes the company's actual performance is compared to quality targets for selected reliability indicators that measure continuity of supply.

Deviations of actual quality from the target result in either a reward or a penalty. The quality targets can be set separately for each network operator (applied in electricity distribution in Germany) or for groups of operators (Italy sets targets regionally reflecting customer density differences). When setting the individual targets, the NRAs can also use comparisons with other network operators.

The quality incentive schemes can incorporate caps on the penalties/rewards (applied in electricity distribution in Germany) and dead bands (applied in electricity distribution in Italy). For quality levels within the dead bands, no penalties or rewards are applied. Dead bands are used to reduce the impact of short-term quality fluctuations.

NRAs in all investigated countries apply quality regulation incentive schemes. The quality incentive schemes have been effective. For example, Italy has been using regulatory quality incentives for more than 20 years during which the quality regulation managed to achieve an overall quality improvement and reduce the difference in quality performance between the Southern and Northern regions.[9] This positive trend is also due to recent regulatory tools introduced to increase the resilience of the network to various climatic threats.

Norway has implemented a quality incentive scheme in 2001. Although the regulation developed over time, the central idea of quality-dependent revenue caps remains. In the current arrangement, the cost of energy not supplied is used in the efficiency analysis to establish the cost norms for the distribution operators.

In Great Britain, reliability improvements since the beginning of RIIO-1 (2015 – 2023) for electricity distribution have resulted in a reduction in customer interruptions of 15% and a reduction in customer minutes lost of 10% in the first five years of RIIO-1 (Ofgem, 2020d). In RIIO-1, Ofgem maintained the interruptions incentive scheme from the previous regulatory period, however there were some modifications to the incentive rates, revenue exposure and targets (Ofgem, 2013a).

In Australia, consumers experienced fewer distribution network outages from 2011 to 2020 (AER, 2021a). The NRA in Australia has found that the Service Target Performance Incentive Scheme (STPIS) has delivered improvements in the reliability of electricity supply, but that network operators have focused on reducing the number of short interruptions to supply, rather than also reducing the number of longer interruptions. Consequently, customers at the end of networks (often in rural or remote areas) were not receiving the same supply improvements as customers in urban areas. In 2018 amendments were made to the STPIS to achieve better reliability outcomes for all customers, including those in rural areas (AER, 2018a). This is an example similar to other regulatory instruments, that the process is not static. As the NRA

9 In 2021, the duration of interruptions for low voltage users has decreased to 62 minutes (from 86 in 2019), spread over 21 minutes (39 in 2019) for reasons not attributable to distributors (mainly due to force majeure following exceptional events) and the remaining 41 minutes of distributors' responsibility (this is the part subject to regulation), with an improvement compared to the 47 minutes recorded in 2019. The number of long interruptions (those over 3 minutes) also improved with 4.07 for low voltage users (against 4.62 in 2019).

gained knowledge and information, and reviewed the regulatory tools and their intended outcome, these have been adapted and improved.

In Germany, since the second regulatory period (2014-2018) electricity distribution network operators are subject to a quality of supply incentive scheme. Furthermore, reporting is required to provide information on the time, duration, extent and cause of the supply interruptions in their networks. Since 2006 the system average interruption duration index (SAIDI) was reported at 21.53 minutes with a gradual improvement. In 2014 the SAIDI was 12.28, 10.73 in 2020and in 2021 the SAIDI was reported as 12.7 minutes (national wide figures) (BNetzA, 2022b).

3.7.3 Targeted Investment Incentives

In the context of the energy transition, network operators will need to continue investing in transmission and distribution grid assets aimed at integrating further Renewable Energy Sources (RES), increasing cross-border exchanges, facilitating the European market integration and improving security of supply. Some countries have opted to establish financial incentives to prioritise certain investments. Such incentives may promote the realisation of investments aiming to alleviate network constraints, enhance network security, increase import and/or export capacity to support market integration, etc.

Given the limited capacity of transmission infrastructure, increases in electricity flows can cause congestion in the network. In Germany the regulator applies an incentive mechanism for the congestion management costs of the transmission network operators (see section 5.4.4).

In Italy, the NRA introduced incentive mechanisms to encourage the extension of transmission interconnection capacity. As a result, the Italian TSO increased the cross-zonal capacities of four internal network boundaries by using different measures (for special protection schemes including RES controllability and dynamic line rating). The cumulative increase of transfer capacities was 1450 MW and the total reward to Terna was about 143 million Euro (103 million Euro for the capacity increases, 40 million Euro for the CAPEX savings) (ARERA, 2022d).

In Belgium, the NRA has also put in place a set of incentives for the TSO to encourage efforts towards market integration and enhancement of security of supply (see section 9). The NRA also applies an explicit incentive to the costs associated with the procurement of ancillary services, which is based on its ex-post assessment of the “fair value” of ancillary services costs (see section 8.5.2). The effectiveness of these incentives applied in Belgium is not yet known as they are relatively new.

3.7.4 Incentives for Achieving Environmental Objectives

NRAs may want to incentivise network operators to achieve specific environmental objectives. For instance, by providing financial rewards for meeting these objectives.

In Great Britain, specific outputs (such as business carbon footprint, environmental scorecard, and annual environmental report) related to the objective “Deliver an environmentally sustainable network”, both for electricity transmission and electricity distribution are applied. These environmental goals fall under the so-called Output Delivery Incentives (ODI). The purpose of this output is to encourage network operators to minimise their own environmental impact, including direct network emissions and business carbon footprint emissions. This requirement calls for the network operators to report their business carbon footprint with a reputational incentive, meaning there is no financial reward or penalty under this incentive (see section 6.5.1). Network operators have reduced their business carbon footprint, reduced emissions and network losses based on a review for the first 5 years of the current regulatory period (CEPA, 2018).

In Australia, the Demand Management Innovation Allowance Mechanism (DMIAM) provides funding within the regulatory framework for research and development (R&D) projects. This mechanism is designed to support the network operators to develop innovative ways to deliver ongoing reductions in demand or peak demand. The following requirements need to be met in order for projects to be eligible, these projects should consist of:

- Research, develop or implement demand management capability or capacity.
- Innovative, in that the project or program is based on new or original concepts.
- Involves technology or techniques that differ from those previously implemented.

This incentive is also related to the goal to achieve net zero emissions by 2050 and adapting to climate change (AER, 2017).

In respect to the effectiveness of specific incentives for the achieving environmental target this is a rather specific instrument which has not been so widely applied.

3.7.5 Business Plan Incentive

In Great Britain, the business plans that network operators need to submit play an important role in the revenue setting process. The NRA applies a Business Plan Incentive (BPI) to encourage the network operators to submit high-quality and robust business plans. The purpose of the BPI is to strengthen the benefits for consumers by rewarding network operators for plans that offer consumers additional benefits and value for money. Network operators that submit business plans that fail to meet minimum requirements and/or have poorly justified cost forecasts are penalised.

Plans show savings of more than £2bn versus previous forecasts, following analysis and benchmarking of costs (Ofgem, 2014). This is a result of the NRA's review of the initial business plan submissions followed by a review of the network operators' resubmission based on the NRA response. See section 6.3.2 on the cost assessment methods applied.

With regard to effectiveness, a common feature is information asymmetry. However, according to the NRA, "*the distribution network operators have generally submitted good quality plans which demonstrate strong stakeholder engagement. They have provided significantly greater amounts of information for public scrutiny on their websites than ever before*" (Ofgem, 2013b). This can also be attributed to the NRA in Great Britain providing guidance documents and templates which set out the type of information needed for the business plan and for increasing transparency of the data requirements.

3.8 Role of Forward-Looking Methods

Forward-looking regulatory estimations are used to integrate the forecasted efficient costs in the allowed revenue (OPEX and CAPEX) for the upcoming regulatory period. They can be used to encourage efficiency improvements and to provide incentives for the necessary spendings on investments and maintenance.

Forward-looking regulatory estimations are typically implemented in the framework of the building blocks approach. The building blocks approach is widely regarded as an effective and comprehensive way of adopting a cost-linked incentive regulation. This approach sets the allowed revenue of the regulated company on a forward-looking basis before the start of the regulatory period.

In order to set the allowed revenue for regulated network services, NRAs need to determine the efficient forward-looking OPEX and CAPEX projections for the following regulatory period. The cost projections can be based on historical costs and adjusted to account for future conditions (indexation).

Alternatively, cost projections may be set by using explicit forward-looking forecasts that do not rely on historical costs. These two approaches are further described below.

3.8.1 Indexation

In this case, the projected costs are the result of a regulatory formula that annually adjusts the allowed revenue whereby the starting point is based on the company's actual costs during a pre-specified period.

For example, in Finland, the NRA sets the allowed (reference) OPEX for the first year of the regulatory period equal to the average of the previous four years. In the subsequent years of the regulatory period, the allowed OPEX is calculated by indexing the reference OPEX from the previous year with the inflation, productivity improvement and changes in network volume. The network volume is a composite variable that comprises the length of overhead lines and the number of substations.[10]

A similar approach is also applied in Germany. The allowed annual OPEX (excluding non-controllable OPEX) is indexed by inflation and efficiency improvement factors (individual and general X factors). The starting point is based on the company's actual cost based on three years before the start of the regulatory period.

3.8.2 Explicit Forward-Looking Assessments

This approach connects the allowed revenues with explicit forward-looking cost projections from the network operator. This appears particularly suitable when there are strong investment and maintenance needs in the near future as their costs can be directly incorporated in the allowed revenues.

The main challenge is to avoid inflated cost projections by the network operators. NRAs therefore apply various forms of analysis to counteract this. Examples of such forms are time series analysis, comparative analysis, cost driver analysis, replacement cost analysis and project specific CBA / technical reviews.

Below we provide some details on these types of analysis and how they can inform the regulatory reviews and setting revenue by estimating the efficient costs of the network operators.

Time series analysis (trend analysis) is a way of analysing a sequence of observations on the same variables at various points collected in time. In the current context, observations regarding a single business entity are used. It is a top-down technique mostly used to compare forecast expenditures (by categories or aggregated) with their historical levels. The analysis can be applied to compare the forecast figures with the actual expenditures in previous periods or the current forecast with forecast figures from previous periods. Overall regulators aim to form a view on the extent to which the historical cost levels can indicate patterns and trends for the required future expenditures (predictive power) and should seek to understand the reasons for the identified variances.

10 The network volume is calculated based on the total length of the overhead lines and the number of substations weighted by the respective cost coefficients. The cost coefficient for the overhead lines in the fifth regulatory period is given by the ratio between average costs of maintenance of overhead lines in 2014-2018 and the total length of overhead lines. The cost coefficient for substations in the fifth regulatory period is given by the ratio between average costs of maintenance of substations in 2014-2018 and the number of substations.

The comparative analysis looks at data pertaining to the same period (e.g., for specific year) for a sample of network operators. The analysis is typically used to compare the expenditures (by various categories or aggregated) across the regulated network operators for that time period.

NRAs apply cost-driver analyses to examine cost forecasts and check the consistency of their assumptions. For example, they investigate the functional as well as Granger causal relationships between expenditures and cost drivers (e.g., number of customers, peak demand, etc.) by using regression models. The estimated functions are used to establish forward-looking cost projections and to validate the submissions of the network operators. For example, in Australia, cost drivers such as demand, peak load and the number of connected customers are used in the CAPEX forecast. In addition, the OPEX forecast considers forecast increases in the size of the network (output growth) (see appendix A2).

In the area of forward-looking CAPEX assessment, NRAs can apply an analysis of the expected replacement investments (replacement CAPEX or REPEX). A replacement CAPEX analysis aims to forecast the physical and financial volume of assets that a network operator will need to replace in the future. Specifically, the analysis examines the age of assets already in commission and calculates the time at which the regulated company will need to replace them based on historical replacement practices. The physical volumes are monetised using unit costs for the various assets.

NRAs can undertake CBA or technical reviews to assess individual projects and compare potential alternatives. The NRAs in Great Britain and Australia have been using forward-looking approaches to assess ex-ante the allowed revenues of the network operators.

The methods applied to obtain forward-looking cost estimations are sometimes based on exogenous inputs, i.e., reference values established by the NRAs, usually with the support of external experts. Other approaches stem from econometric analyses based on historic data. NRAs uses a combination of different approaches to mitigate potential inaccuracies resulting from uncertainties in the forecasting process or limitations in the models' predictive power.

In terms of effectiveness, experience so far supports the notion that the allowed revenues using forward-looking assessments with carefully calibrated incentives can encourage investments, and drive innovations. The main challenge of the forward-looking assessments is that they carry an inherent risk that NRAs set wrong allowances and/or targets due to the information asymmetries at the time when the allowed revenues are set. This issue is also related to the lack of data especially when dealing with assets incorporating state-of-the-art technologies. In order to mitigate forecast inaccuracy, NRAs apply various methods and tools to assess cost projections. Moreover, uncertainty mechanisms (e.g., volume drivers, re-openers, and pass-through provisions) allow adjustments to the allowed revenues during the regulatory period. This is to reflect changes related to the need, volume and timing of the planned works. The instruments to address uncertainty are addressed in the following chapter 3.9.

Example of Application in Australia

In order to ensure that the forward-looking forecast proposed by the network operators is efficient, the Australian NRA uses a number of techniques such as trend analysis, predictive modelling (for example CAPEX replacement needs) and technical reviews.[11] As part of the review, the Australian NRA also examines the forecasting methodology and underlying assumptions applied by the network operators.

This includes looking at the decision-making process that determines the scope and inclusion of each CAPEX program and project that contributes to the forecast. The NRA may also decide to compare a network operator's approach to its forecast with those of other electricity network operators and look further into those areas that do not align with good

11 The Australian regulator applies stochastic elements in the modelling of the asset replacement needs for the purposes of the CAPEX forecast. The annual forecast volume of assets to be replaced is calculated by taking into consideration the volume of assets in the respective age segment and the appropriate probability taken from a probability distribution function that reflects the statistical proportion of assets that need to be replaced at a given age.

practice. Furthermore, the NRA may apply economic benchmarking to compare the performance of a network company with both its own past performance and that of other electricity network operators. For large projects that have been subjected to ex-ante regulatory investment tests (RIT) as applied in Australia, CBA is applied for these projects.

3.9 Dealing with Uncertainty

European network operators are currently engaged to deliver on ambitious decarbonisation goals in an increasingly complex, decentralised and uncertain environment. There is uncertainty regarding:

- Future demand for electricity and natural gas
- Future network capacity needs
- Efficiency improvements and penetration of new technologies

In such an uncertain environment, there is a risk that the actual efficient costs deviate from the allowed revenue trajectories leading to financial surpluses or shortfalls to the network operators.

There are different regulatory mechanisms that NRAs use to manage uncertainties. We discuss the most relevant ones in the following sections.

3.9.1 Revenue Adjustment Schemes

Revenue adjustment schemes are ex-ante rules that define how revenue allowances can be adjusted for differences between what has been assumed while setting the allowed revenues and what occurs in practice. Revenue adjustment schemes may be used to consider uncertainties regarding investments for example.

The application of revenue adjustment schemes requires a clearly defined and measurable variable (for example volume of renewable connections) which drives costs, and which can be used as the basis of the revenue adjustment. Examples of revenue adjustment schemes are provided in section 5.3.5 and 6.8.

3.9.2 Interim Review (or Re-opener)

At an interim review (or re-opener) the NRA reviews particular issues and determines new or adjusted changes to the allowed revenues for the network operators. This allows an NRA to take account of costs related to certain events, such as significant external shocks or material changes in circumstances.

Consequently, this tool reduces the risk the network operator faces from the occurrence of certain types of unexpected events. The interim review may consist of a full cost review (like, for example, in Italy where the regulatory period is divided into two subperiods) or only consider costs related to a specific investment or event. The events that might trigger an interim review may be defined by the NRA or left open.

For example, in Germany revenues can be adjusted in case of unexpected events (hardship clause) which lead to a large negative impact on the network operators that cannot be endured by them.

The main advantage of interim reviews is that the NRA does not need to wait until the end of the regulatory period to adjust the allowed revenues. It further offers the network operator a certain element of stability and protection. However, it can introduce some instability and uncertainty in the regulatory process. It may reduce the incentives for cost efficiency (as network operators would not have the incentive to prevent or minimise costs related to certain events), and it constitutes a burden on the NRA.

There are cases where an interim review can be requested by both the network operator and the NRA and others where only the NRA or the network operator can request one. For example, the Net Zero Re-opener in Great Britain can only be triggered by the NRA. This re-opener has a broad scope to ensure that RIIO-2 framework can be adapted to a wider range of potential developments. It allows the NRA to adjust allowed revenues and amend outputs in response to changes in government policy, the role of network operators, or technological or market developments. To trigger this mechanism, the expected changes to allowances made under the re-opener (materiality threshold) exceed 0.5% of the annual allowed revenues.

The reopener is an effective tool to accommodate unforeseen changes and developments, especially in respect to the energy transition and meeting decarbonisation goals.

3.9.3 Trigger Mechanisms

A trigger mechanism is an automatic adjustment of regulatory components that occurs if a certain parameter moves above or below a pre-determined threshold. The main advantage of a trigger mechanism is that it creates regulatory certainty. A trigger mechanism is similar to a re-opener mechanism. The main difference is that a trigger mechanism follows a mechanistic formula, whereas a re-opener has in general a broader scope (depending on its specific design). The NRAs can decide about the level of flexibility when applying a certain regulatory tool. The NRA can reduce flexibility in re-openers by clearly defining the circumstances under which it can be applied. On the contrary, the NRA can also increase flexibility by allowing a re-opener for changes of circumstances above a certain amount.

For example, in Italy ARERA decided to implement a trigger mechanism over the period 2023-2024. During this period, the WACC is updated only if the cumulated impact of updating individual parameters is above a pre-determined threshold (50bps).

3.9.4 Indexation / Quantity Adjustment Factors

Indexation

Indexation of cost allowances reduces the risk to network operators from unanticipated cost rises. This mechanism provides network operators protection against the risk that actual prices differ from those that were forecast when setting the price control. This mechanism transfers the risk from price changes from network operators to network users.

For example, RPI-X regulation applied to OPEX in Italy indexes the OPEX during the regulatory period to changes in consumer prices. In Great Britain a real price effects (RPE) indexation mechanism is applied, which protects network operators and consumers from the risks of differences between input price trends and Consumer Prices Index (CPIH).

Quantity Adjustment Factors

Quantity adjustment factors represent a regulatory mechanism used to support cost recovery when there is uncertainty about how demand will develop over the regulatory period.

These factors link allowed revenues to selected cost drivers (energy demand, number of customers, length of network, etc). The allowed revenues are adjusted annually based on observed changes in the cost drivers. The advantage of this type of adjustment is that total revenues can track total costs more closely, thus reducing the risk of persistent revenue shortfalls for the network operators. Quantity adjustment factors can be used to supplement the main price control allowances when. An example of its application can be when there is a significant delay between the time of capital expenditures and the time of RAB integration.

A variation of this instrument was applied in the first and second regulatory periods of the German regulation for electricity distribution. That quantity adjustment factor took account of several drivers (expansion of network area, number of connection points, peak load) and adjusted allowed revenues based on changes in these drivers. It was a regulatory mechanism allowing DSOs to request an adjustment to the allowed revenue if changes to specified drivers caused controllable costs to increase by more than 0.5%. This mechanism has now been replaced by the capital cost adjustment factor (see section 5.5.2).

The NRA in Great Britain also uses quantity adjustment factors. It applies volume drivers to adjust the allowed revenues in line with actual volumes. In this way, it aims to better manage uncertainty. For example, uncertainty can be associated with the amount of load-related CAPEX that is required to connect new generators. and as well as customers to the transmission network.

3.9.5 Cost Pass-through

This mechanism allows network operators to pass through the cost of an item to network users. Generally, the costs which are allowed to be passed through are those over which the network operator has no control (for example, concession fees and property taxes). The challenge of this mechanism is to establish to what extent certain costs are within a network operator’s control. The mechanism reduces the uncertainty for the network operator but may also reduce a network operator’s incentive to become more efficient.

Pass-through mechanisms are currently used in Great Britain to adjust allowances for costs incurred by the network operators over which they have limited control, e.g., business rates and licence fees.

3.9.6 Menu of Regulatory Options (Contracts)

Conceptual Background

Theories of optimal regulation often assume that regulators are completely informed about the technology, costs and demand faced by the regulated firm. However, in practice, this is often not the case. Models of economic regulation recognise, and address, two sources of informational problems (Joskow, 2009):

- Uncertainties about the firm’s inherent cost opportunities. The inability of regulators to discern whether a firm has cost-reduction opportunities gives firms a strategic advantage.
- Uncertainties about the managerial effort. Managerial effort reduces the firm’s costs, all other things being equal. It is also necessary for the full realisation of the firm’s cost opportunities.

Several academics (Laffont and Tirole, 1993; Baron and Myerson, 1982; Laffont and Tirole, 1986) developed economic models to deal with the informational asymmetry problems surrounding firms’ cost opportunities and managerial effort. The solution involves a regulatory mechanism that takes the form of sharing schemes, where the regulated price is partly responsive to changes in realized cost and partly fixed ex ante.

At a general level, it has been argued that one way to address the information asymmetry between a regulator and network operators is to present each company with a range, or “menu” of regulatory contracts which contain different profit-sharing possibilities, and that this approach will be more efficient than providing only a single regulatory contract. By offering a company a menu of regulatory contracts/options with different profit-sharing provisions, the NRA can encourage companies with low-cost opportunities to choose a relatively high-powered incentive scheme. Such schemes are characterised by a significant potential to outperform the regulatory targets, and equally significant downsides if these targets are missed. Moreover, companies with high-cost opportunities can be encouraged to opt for a low-powered incentive scheme, i.e., one with limited scope to outperform or the potential to underperform.

One of the main advantages of menu regulation is reducing the regulatory burden for NRAs as the menu identifies companies with potential for cost reductions. Moreover, it increases the transparency of the regulatory system as the menu incentivises companies to submit more accurate business plans. However, it may be difficult for the NRA to design an appropriate menu, particularly if it has not implemented menu regulation before. The technical complexity of this regulatory tool also makes it less transparent for consumers.

Practical Application

The regulatory framework in Great Britain had in the past employed menu regulation for both electricity and gas distribution.

The Information Quality Incentive (IQI) mechanism (2009) (Ofgem, 2009) encouraged the electricity distribution network operators to submit accurate CAPEX forecasts by providing lower returns to companies that overestimate their expenditures.[12] Each network operator had to submit its forecast of its entire CAPEX for the next regulatory period. Additionally, the NRA developed its own CAPEX estimation, the so-called “Ofgem baseline”. The ratio of the network operator’s forecast and the Ofgem baseline is the “performance ratio”. In the example provided the performance ratio is at least 100% because the Ofgem baselines were lower than the forecasts submitted by the network operators in their business plans.

The IQI matrix (see figure below) includes two incentives. First, the network operator earns an additional lump-sum income that is larger the closer its forecast is to the Ofgem baseline (i.e., Ofgem’s own forecast). Second, there is an incentive rate for future efficiency gains based on how close the network operators’ forecast is to Ofgem’s baseline. A network operator with an inflated CAPEX forecast retains a lower percentage of any CAPEX underspend than a network operator with a more accurate forecast. Network operators earn the highest income by accurately forecasting their intended CAPEX spend (this is highlighted in blue).

For example, if the Ofgem baseline is £100m for CAPEX and the network operator expects to spend 100% of the Ofgem forecast, it will earn an income of £4.5m by not inflating its forecast. This is calculated as (£105m-£100m) x 40% + £2.5m.[13] In contrast, if it inflated its bid to 140% of the Ofgem forecast whereas its actual CAPEX amounted to 100% it would only earn an income of £0.6m (highlighted in yellow) as it loses out on both the additional income incentive and the efficiency incentive. For a given forecast, network operators are better off when the actual CAPEX is lower than the baseline. For example, if a network operator forecasts expenditure of £110 but spends only £100, it earns a reward of £4.3m, which is greater than £0.8m.

12 This has now been replaced by the business plan incentive (see section 6.7.1)

13 The reward is then calculated according to: Reward = (allowed expenditure – actual expenditure) x efficiency incentive + additional income

Performance Ratio	100	105	110	115	120	125	130	135	140
Efficiency incentive rate	40%	38%	35%	33%	30%	28%	25%	23%	20%
Additional income	2.5	2.1	1.6	1.1	0.6	-0.1	-0.8	-1.6	-2.4
Allowed CAPEX	105	106.25	107.5	108.75	110	111.25	112.5	113.75	115
Actual CAPEX									
70	16.5	15.7	14.8	13.7	12.6	11.3	9.9	8.3	6.6
80	12.5	11.9	11.3	10.5	9.6	8.5	7.4	6.0	4.6
90	8.5	8.2	7.8	7.2	6.6	5.8	4.9	3.8	2.6
100	**4.5**	4.4	4.3	4.0	3.6	3.0	2.4	1.5	0.6
105	2.5	**2.6**	2.5	2.3	2.1	1.7	1.1	0.4	–0.4
110	0.5	0.7	**0.8**	0.7	0.6	0.3	–0.1	–0.7	–1.4
115	–1.5	–1.2	–1.0	**–0.9**	–0.9	–1.1	–1.4	–1.8	–2.4
120	–3.5	–3.1	–2.7	–2.5	**–2.4**	–2.5	–2.6	–3.0	–3.4
125	–5.5	–4.9	–4.5	–4.2	–3.9	**–3.8**	–3.9	–4.1	–4.4
130	–7.5	–6.8	–6.2	–5.8	–5.4	–5.2	**–5.1**	–5.2	–5.4
135	–9.5	–8.7	–8.0	–7.4	–6.9	–6.6	–6.4	**–6.3**	–6.4
140	–11.5	–10.6	–9.7	–9.0	–8.4	–8.0	–7.6	–7.5	**–7.4**

Figure 2: Menu Regulation / sliding scale matrix (applied in DPCR4 2005-2010)

Source: Ofgem (2008)

With regards to effectiveness, the NRA considered that the IQI was beneficial in terms of encouraging some network operators to submit revised forecasts at the fourth Distribution Price Control (DPCR4) reducing CAPEX. However, there were also some concerns about the application of the IQI mechanism. The IQI mechanism assumes that network operators are risk-neutral, however they may be risk averse and try to protect themselves against increases in costs. For example, if Ofgem baseline for CAPEX is £100m and the network operator considers it needs £110m, if it moves its forecast one column to the right it obtains insurance for higher costs through its allowance increasing by £1.25m. Its reward under the IQI is only reduced by £0.1m (£0.7m instead of £0.8m).

The IQI mechanism was introduced after the network operators submitted their initial business plans. An annual cost reporting process was introduced to monitor year-on-year changes in costs. In addition, network operators had the opportunity to revise their CAPEX projections subsequently, before Ofgem's final decisions. Therefore, a network operator may submit a high CAPEX forecast at an early stage to influence Ofgem's baselines and then submit lower forecasts to benefit from higher cost incentive rates and cash rewards under the IQI mechanism.

3.10 New Thinking / New Concepts

There is a trend in regulation of electricity network operators towards creating value for society as a whole, instead of focusing exclusively on the provision of network services. NRAs are following this trend by establishing incentives to reach pre-specified targets or outputs.

The purpose of this section is to consider additional innovative instruments that can be used to facilitate the transition to a low-carbon, environmentally sound and reliable energy system. Below we describe examples of regulatory incentives that are not commonly applied in every regulatory framework and have some innovative features. The focus is on concepts and instruments that have not been covered in the previous sections.

Incentive for Controlling and Prioritising Investments

The changes driven by the energy transition, the connection of renewable energy, and the necessary renewal and expansion of the electricity network all require significant investments. For this purpose, giving an adequate level of priority to these investments by means of a financial incentive could be one option to ensure that the network operators are prioritising necessary investments.

For example, the NRA in France defines a four-year envelope which is an investment cap. The network operator has an incentive not to exceed this envelope, and therefore, to control its expenses and prioritise its projects (CRE, 2021).

If the sum of the actual capital expenditures over the regulatory period is lower than the investment cap, no penalty or bonus applies. However, if the sum of investments over the regulatory period exceeds the investment cap, then a penalty, equal to 20% of the overrun, is applied to the network operator.

The investment cap covers specific groups of investments caused by the connection of renewable energy and the necessary renewal of the network).[14] The investment cap is calculated over the regulatory period. It gives the network operators the flexibility to manage any project delays or periodic additional costs and encourages them to optimise the process of investment planning.

The network operator will submit to the NRA an implementation report on an annual basis referring to year N-1. This report will specify any differences between the actual trajectory and the forecast trajectory of investments within the scope of the investment cap and will explain the choices made in terms of the prioritisation of investments and the measures taken to comply with the envelope defined at the start of the regulatory period.

End-of-life incentive

Under the more traditional regulatory regimes, network operators may have an incentive to replace assets when they reach the end of their regulatory asset life ("bias" towards CAPEX-intensive solutions), instead of looking at asset management and maintenance solutions that facilitate the extension of the assets' useful life. This is the case when network operators cease to receive a return on assets that have no residual value in the RAB. Moreover, it may be difficult for NRAs to identify this "capital bias" by reviewing investment plans.

End-of-life incentives aim to prevent the replacement of network assets that have reached the end of their regulatory lifetime (depreciation period) but for which the technical condition is still good. The end-of-life incentive, therefore, provides remuneration for assets for an additional number of years. The financial incentive could consist of an increased OPEX

14 A specific regulatory framework is applied to "non-grid" investment expenses. In addition, offshore power connection projects and new high-voltage, direct-current interconnection projects are very large-scale projects, whose timetable can vary significantly and outside RTE's control, with a very substantial impact on investment expenses.

allowance (applied for example in Spain (CNMC, 2019) or capital cost allowance (applied for example in Portugal (ERSE, 2017).

Based on the NRA in Portugal, the end-of-life incentive was effective in avoiding a direct link between the level of allowed revenues and the level of investment. As a result, investment decisions are made while considering technical and economic criteria for investment, operation, and management of the infrastructure.

Incentive for the Provision of Data

The provision of data infrastructure and the timely publication of high-quality data by network operators is of major importance for market participants that utilize this data. For example, a new business model might be based on using close-to-real time market information on network congestion to enable smart demand-side responses.

The NRA in France introduced indicators on compliance by the TSO, through deadlines for publication (or transfer) of data identified as a priority for participants (for example data related with the capacity and balancing mechanism). The NRA applies penalties for non-compliance with the deadlines.

Incentive for the Achievement of the Electricity Generated from Renewable Sources (RES-E) Targets

In the context of decarbonisation, NRAs may use explicit incentives to encourage the network operators to facilitate the transportation of renewable electricity. NRAs could reward network operators for the actions they have taken to achieve the annual RES-E targets set by the NRA, which can be measured by the portion of electricity coming from renewable sources each year.

In Ireland, the Commission for Regulation of Utilities (CRU) introduced such incentives for the TSO, with respect to its contribution to the achievement of 70% renewable electricity by 2030 and achieving net zero carbon emissions by 2050 (CRU, 2020).

The TSO is required to submit a multi-year plan setting out the planned actions involved in achieving the RES-E targets. To measure and assess the actions carried out by the TSO to achieve the RES-E targets, a balanced scorecard is established. The NRA in Ireland will assess the TSO in the following areas:

- Achievement of the RES-E target (if the annual target is not achieved, no reward will be applied).
- Quality of the plan.
- Quality of the implementation.
- Effectiveness of the plan.

Control over the outcomes in these areas is one of the main principles of the incentive, and as such, a balanced scorecard will ensure the TSO is rewarded based on its actions. This is to avoid that the TSO may be rewarded in cases where the target was achieved without the deliberate action of the TSO e.g., changes in demand.

Stakeholder engagement incentive mechanism

The objective of this incentive is to encourage the network operators to improve their engagement activities, i.e. how network operators understand and address the needs of stakeholders and how their input is used to improve network services.

In Ireland, the network operator is subject to a financial incentive on the scope, quality, and outcomes/impacts of its stakeholder engagement activities. Performance is measured through an annual assessment of the network operator’s strategy for stakeholder engagement, and the processes and activities undertaken by the network operator corresponding to that strategy over the previous calendar year. The assessment takes the form of an annual submission by the network operator, consistent with guidelines set by the regulator.

The following weights are used in the assessment:

- 20% - quality of stakeholder engagement strategy, and management systems and processes within the business to enable its delivery.
- 40% - quality of delivered set of channels and initiatives for engaging with stakeholders.
- 40% - quality of demonstrable positive impacts on stakeholders, stakeholder groups or the business consequent to the delivered channels and initiatives.

The Networks Stakeholder Engagement Evaluation (NSEE) panel evaluated the stakeholder engagement activities of the TSO (and DSO) over 2018 and 2019. The NRA in Ireland published the close-out report for the NSEE panel process in relation to TSO and DSO performance in 2020 (CRU, 2019). According to the NSEE panel the process worked well. With the network operators receiving and implementing recommendations for improvements provided by the Panel.

Joint incentives

The changing role of electricity networks resulting from the energy transition requires more collaboration and coordination between network operators. Thus, NRAs may decide to apply joint incentives on transmission and distribution network operators. The purpose of such incentives would be to provide effective signals to the companies to act jointly and align their activities in terms of planning, operation and innovation.

An example of joint incentives has been introduced by the NRA in Ireland, namely the TSO/Transmission Asset Owner (TAO) joint incentive. The purpose of this incentive is to improve collaboration and innovation in the delivery of transmission network improvements related to the deployment of new technology,[15] and to enhance asset and programme data exchange.[16]

Similarly, the Irish TSO/DSO joint incentive is meant to improve collaboration on the security of supply/constraints. While this is currently set out as a TSO incentive, the DSO has an important role to play in the security of supply. In addition, the "whole of system" approach incentivises the DSOs and TSO to optimise the network as a whole rather than focusing on each network separately. The Irish NRA believes that better coordination between the DSO and TSO could bring beneficial outcomes to consumers in the form of lower network tariffs and a more reliable supply of electricity. This coordination may also enhance the development of infrastructure that benefits the distribution system but is located on the transmission network and vice versa.

Metrics to evaluate performance include both quantitative and qualitative metrics which are evaluated through a balanced scorecard framework. This framework will evaluate performance and be graded as “strong”, “acceptable” or “below acceptable”. The incentive payments are set by the Irish regulator and will be based on an independent audit. The Irish regulator establishes maximum rewards and maximum penalties for financial incentives (CRU, 2022).

15 This is to ensure that not only are the processes effective in enabling the trialing and piloting of new technology but also, that the TSO and TAO actively deploy and use new technology on the grid. This metric could include optioneering assessments, deployment of technology and a review of effectiveness.

16 This examines the TSO and TAOs performance on the exchange of information and provision of access to transmission asset transmission work planning and delivery IT systems, data libraries, asset data, with respect to delivery of transmission network CAPEX program for the 5th regulatory period.

4 APPLICABILITY

Building on the results and findings, in this chapter we assess the usefulness of regulatory instruments and the associated options for the regulatory arrangements in the Netherlands.

We first provide a description of the current regulatory arrangements for the Dutch electricity transmission and distribution network operators, then we assess the applicability of the instruments against a set of predetermined criteria.

4.1 Status Quo – The Netherlands

The Authority for Consumers and Markets (ACM) is responsible for the regulation of the electricity networks in the Netherlands. ACM applies a revenue cap for the transmission network and tariff basket caps for the distribution networks. The current regulatory period for the electricity transmission and distribution is 2022-2026 (5 years). The legal framework allows to set the length of the regulatory period equal to 3-5 years.

Transmission

The allowed revenue for transmission services provided by TenneT is set equal to the expected efficient costs.[17] This includes operating expenditures (OPEX) and capital costs (depreciation and return on assets).[18] OPEX is set for the existing network (based on the average in the three most recent years of available information before the current regulatory period). It is then adjusted for efficiency improvements and additional OPEX is added for network expansion.

To determine the efficient capital costs of existing assets and new investments ACM rolls over the (efficient) capital cost of existing investments and adds CAPEX for an expected increase of the network during the regulatory period ('Doorrollen en bijschatten'). The latter is based on the actual investments in three reference years and excludes the investments subject to t-0 regulation (see below). For investments with a lifespan longer than 10 years, ACM allows full reimbursement of the capital cost by an ex-post revenue correction.[19] This is based on the actual investments.

Large expansion investments are subject to the t-0 regulation. Their capital costs are reimbursed in the year that they are incurred. This is based on estimations provided by TenneT annually. Later (typically at the end of the regulatory period) the estimated amount is corrected with the actual efficient costs. The efficiency of these investments is based on project-specific efficiency tests. ACM recognises also an additional OPEX of 1% (yearly) of the investment costs.

ACM determines the efficient costs for TenneT by comparing it with other European TSOs in an international efficiency study (a so-called benchmark). ACM also incorporates a factor for productivity improvements resulting from technological progress (dynamic efficiency/frontier shift) when setting the efficient cost level for TenneT. The estimation of the frontier shift is based on an analysis of selected sectors of the Dutch economy as well as on available research on the TSO's dynamic efficiency.

If TenneT operates more efficiently than the revenue cap set by ACM, it may keep the resulting efficiency gains. On the other hand, if it operates less efficiently and has higher costs than the target, it incurs a loss.

The energy costs and congestion management costs are only reimbursed partially. They are subject to a bonus/malus scheme. The energy costs for ancillary services (system operation) are reimbursed fully.

17 ACM regulates also separately the provision of system services and offshore transmission services.

18 Depreciation is calculated by using a straight-line method on the basis of the technical lifespan of assets.
The return on assets is determined as a product of the (pre-tax) WACC and the Regulatory Asset Base (RAB).

19 ACM applies the regulatory WACC to calculate the return on assets used for in the reimbursement.

Distribution

Electricity distribution is regulated by tariff basket caps and yardstick competition. In order to determine the allowed revenues for a DSO, ACM first calculates the efficient sector cost per unit of output and then multiplies this with the output level of that DSO (the output includes number of customers, electricity distributed (MWh), capacity (MW) and # connections). The efficient sector cost per unit of output is based on the historic individual costs of the Dutch distribution network operators. The costs for purchasing network services from the TSO Tennet are excluded from the calculation of the yardstick. These historic costs are taken from a three-year span during the previous regulatory period. This time span starts four years prior to year 1 of the current regulatory period.

During the regulatory period, changes (positive or negative) in output levels do not lead to changes in tariffs. The assumption is that costs are scalable with output and hence that tariffs require no changes as the income from extra output covers the extra costs. If that assumption is not met, DSOs take on volumes risk and can earn profits or suffer losses when output does not match historic levels.

The regulatory framework includes an X-factor. The X-factor incorporates the static efficiency (the national comparison between DSOs) and dynamic efficiency (year-on-year change in productivity). ACM considers the scope for improving productivity resulting from technological progress and changing purchasing prices. The X-factor is applied to adjust allowed revenues throughout the regulatory period

Furthermore, a Q-factor (quality of supply) incentive is applied. The Q-factor depends on the System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI). The quality of supply is compared between DSOs. The quality of supply incentive is a zero-sum game, which means that the revenue adjustments stemming from applying Q-factors for all DSOs together add up to zero. Also, a yearly adjustment for inflation is applied. The adjustment apples also for transmission.

4.2 Regulatory Analysis of Applicability

The changing role and tasks of electricity network operators in the course of the energy transition should be reflected in the decisions of adapting the regulatory arrangements. Below we list the relevant areas that need to be considered in the future regulatory framework.

- Encourage investments
- Ensure CAPEX efficiency (ex-ante reviews and ex-post reviews)
- Application of explicit forward-looking regulatory approaches
- Use of explicit incentives to encourage innovation
- Provide incentives for reducing losses/congestion management / ancillary services
- Encourage sector cooperation

The analysis of the applicability of the regulatory instruments in the Dutch regulatory system is based on a set of criteria, these are:

- Economic properties of the instrument,
- Technical complexity,
- Compatibility, and

- Administrative burden/implementation effort.

The first criterion summarises the economic properties of the regulatory instrument relevant for the regulatory areas (purpose / nature and types of incentives/parameters). The second criterion addresses the technical complexity of the regulatory instrument in terms of analytical features, required modelling expertise and competencies, and data requirements. The third criterion examines the compatibility of the regulatory instruments with the arrangements in the current Dutch regulatory system. The last criterion deals with the administrative burden and the amount of effort required to fit the instrument in the current system.

The analysis is presented in the following table.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Efficiency Analysis	Efficiency incentives	• Regulated companies are given (ex-ante) incentives to improve efficiency (reduce costs) through efficiency improvement targets incorporated in the allowed revenues and set with the help of efficiency analysis. • Efficiency analysis can apply methods ranging from parametric and non-parametric techniques to engineering reviews and project specific cost-benefit analyses (CBA).	• The technical complexity of an efficiency analysis depends on the selected methods and the associated data requirements. • The use of methods for comparative analysis of detailed cost assessments are characterised by high technical complexity.	• The application of efficiency analysis is compatible with the current regulation for the Dutch TSO and DSOs. • It should be noted that currently ACM applies efficiency analysis, but there is a large variability between types of efficiency analysis.	• Depending on the methods used for the efficiency analysis, it may require significant amounts of data and regulatory capacity. • ACM has been using efficiency analysis for the TSO and DSOs for many years and is experienced. • However, the use of new types of analysis (see below the explanation on CAPEX reviews) would require significant implementation efforts.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Length of Regulatory Period	Efficiency Incentives	• The duration of regulatory periods affects the power of efficiency incentives. • Sufficiently longer periods (≥3 years) would allow regulated companies to achieve efficiency savings, while keeping some alignment of revenues and costs. • On the other hand, the flexibility of a shorter regulatory period may be beneficial.	• Changing the length of the regulatory period is easy but may also cause changes in the frequency and the scope of the cost reviews.	• Changing the duration of the regulatory periods does not require fundamental changes in the regulatory framework for electricity transmission and distribution. • The current legal framework considers regulatory periods of 3-5 years.	• Changes of the duration of the regulatory period for the TSO and DSOs can be easily implemented. • Changes of the duration of the regulatory period will have an impact on the frequency and the scope of the cost reviews.

Sharing Mechanism	Efficiency Incentives / Investment Incentives	• Sharing mechanisms set incentives for network operators to achieve specific regulatory targets by splitting the benefits and costs of over- or under-achieving these targets between the company and the network users (the customers) according to a pre-defined rule. • If the network operator ends up within a pre-defined range of a target, there is no sharing. Only if benefits or costs are substantial, they are shared between the network operator and its users. • Often these sharing levels are complemented by a maximum and minimum level (cap or floor) above or below which the incremental costs are fully covered by the network operator or its users respectively. • Sharing mechanisms can be applied to integral cost components (for example CAPEX) or to specific cost items (cost of network losses, quality of supply).	• The technical complexity of sharing mechanisms is typically not high and depends on the selected cost block, sharing parameters, length and data requirements. • It may be challenging to determine which gains are a consequence of management decisions and which are windfall gains, resulting for example from changes in the general economic environment.	• The application of sharing mechanisms is compatible with the current design of electricity transmission regulation. • The current yardstick regulation for electricity distribution does not include sharing of efficiency gains. When a DSO operates inefficient relative to the yardstick, it is individually responsible for the efficiency loss. Similarly, a DSO can retain the efficiency gain if it is more efficient than the yardstick. • The application of further explicit sharing mechanisms does not appear directly compatible with the current yardstick arrangements.	• Adopting a sharing mechanism for the TSO would not require significant implementation efforts. • However, cost groups, sharing parameters and data requirements would need to be defined. • A sharing mechanism is not used in the current yardstick regulation for electricity distribution. • The implementation of sharing schemes for the DSOs would require significant change in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Efficiency Carry-Over	Efficiency Incentives / investment Incentives	• Efficiency carry-over occurs if gains resulting from efficiency increases (e.g. saving in CAPEX) are transferred to the next regulatory period. • Efficiency carry-over can be considered as an extension of the sharing schemes. • The design of the carry-over determines the proportion of the efficiency gains transferred to the following regulatory periods and the way how they are incorporated in the allowed revenues.	• The technical complexity of efficiency carry-over schemes is higher than that of sharing schemes because it concerns multiple regulatory periods. • It depends on the selected cost block, carry-over parameters and data requirements. • It may be challenging to determine which gains are a consequence of management decisions and which are windfall gains, resulting for example from changes in the general economic environment.	• The application of efficiency carry-over schemes is compatible with the current design of the electricity transmission regulation. • The application of carry-over schemes does not appear directly compatible with the current yardstick arrangements for the DSOs.	• Adopting an efficiency carry-over scheme for electricity transmission would require moderate implementation efforts. • Cost groups, carry-over parameters and data requirements would need to be defined. • The implementation of carry-over mechanisms for electricity distribution would require significant changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Ex-ante CAPEX review	Efficiency incentives / investment incentives / forward-looking scheme	• The ex-ante CAPEX review aims to assess and recognise the capital cost of the planned efficient investments in the allowed revenue. In such a way that they create certainty and encourage network operators to plan and deliver the necessary investments. • Ex-ante reviews carry an inherent risk of the NRA setting too high (or too low) allowances due to information asymmetries at the time of the review.	• The technical complexity of the ex-ante CAPEX reviews depends on the selected methods and the associated data requirements. • The use of detailed CAPEX assessments by asset groups and individual project analysis is characterised by high technical complexity.	• The application of ex-ante CAPEX reviews is compatible with the current design of electricity transmission regulation. Currently ACM does not apply for ex-ante reviews when setting the allowed revenue. • The application of ex-ante CAPEX reviews is not compatible with the current regulatory framework for electricity distribution.	• Adopting ex-ante CAPEX reviews for electricity transmission would require high implementation efforts. • Depending on the methods used, the application of ex-ante CAPEX reviews would require a significant increase in the level of data reporting and regulatory scrutiny. • Ex-ante reviews require a lot of expertise that an NRA might need to develop or/and obtain from a third party. • For electricity distribution the implementation of ex-ante CAPEX reviews requires fundamental changes in the current regulatory arrangements.

Ex-post CAPEX Review	Efficiency incentives/ investment Incentives	• The main objective of ex-post reviews is to support NRAs in their decision whether to include certain (efficient) CAPEX in the RAB. • The ex-post reviews can provide incentives to network operators to carry out the projects prudently, efficiently and according to the plans. • However, they can increase uncertainties for the network operators that (inefficient) investments can be disallowed ex-post.	• The technical complexity of the ex-post CAPEX reviews depends on the selected methods and the associated data requirements. • The use of detailed CAPEX assessments by asset groups and individual project analysis is characterised by high technical complexity.	• The application of the ex-post reviews is compatible with the current design of electricity transmission regulation. ACM currently applies ex-post reviews for large projects. • The application of ex-post CAPEX reviews is not compatible with the current regulatory framework for electricity distribution.	• Depending on the methods used, the application of ex-post CAPEX reviews would require a significant increase in the level of data reporting and regulatory scrutiny. • Ex-ante reviews require a lot of expertise that an NRA might need to develop or/and obtain from a third party. • Although ACM currently applies ex-post CAPEX reviews for large transmission projects, the extension of such reviews in terms of scope and methods can require moderate to high implementation efforts. • For electricity distribution the implementation of ex-post CAPEX reviews requires fundamental changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
WACC-Mark Up	Investment incentives / innovation incentives	• The use of a WACC-mark up could strengthen incentives for investments. • Furthermore, by distinguishing the mark-up by investment type (as is done in Italy) the NRA can also encourage innovation. • If the investments subject to a WACC-mark up are directly recognised in the allowed revenues, this approach may however lead to a risk of overinvestment. However, this risk may be lower for the DSOs in the Netherlands because of the current yardstick regulation.	• A regulatory judgment is necessary to decide whether an investment qualifies for a WACC-mark up. • Formal criteria would need to be developed in order to qualify for the WACC-mark up. Furthermore, different/additional data would need to be reported on basis of this criterion. • The technical complexity is low.	• The application of a WACC-mark up is compatible with the current regulatory framework	• The application of a WACC-mark up would require no significant changes in the regulatory framework for electricity transmission and distribution. • Furthermore, this approach would not require a significant increase in the level of regulatory scrutiny and can be easily implemented.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Innovation Allowance/ Funding	Investment incentives/innovation incentives	• These instruments can be used to facilitate and encourage innovation, for instance related to decarbonisation.	• Formal criteria would have to be developed and a regulatory judgment would be necessary to review/ decide what investments qualify for funding. • Due to the small number of regulated electricity network companies in the Netherlands, the design and use of such innovation schemes would not be complex.	• The application of innovation allowance and funding is compatible with the current regulatory framework.	• The application of innovation allowance and funding requires no fundamental change in the regulatory framework for electricity transmission and distribution. • However, reviewing whether an investment qualifies for funding and adopting innovation allowance and funding would require additional regulatory scrutiny. • In addition, a transparent procedure would need to be designed to allocate the money for innovation funding. • The additional regulatory monitoring should be feasible given the small number of network companies in the Netherlands.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Quality performance	Efficiency / investment incentives with focus on quality performance	• Under quality incentive schemes, the company’s performance is compared to targets set for selected quality indicators (typically for network reliability) • Deviations from the targets result in either a penalty or a reward.	• The technical complexity of quality incentive schemes depends on the definition of the quality targets and the associated data requirements.	• Quality incentive schemes are currently applied in electricity distribution. Quality is defined by the duration and the number of outages. • Currently, ACM does not apply quality incentive schemes for electricity transmission. The application of such schemes is compatible with the current design of electricity transmission regulation.	• Adopting a quality incentive scheme for electricity transmission would not require significant implementation efforts. • However, quality indicators, targets and data requirements would need to be defined.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Network loss performance	Efficiency/ investment incentives with a focus on network loss performance	• Under loss incentive schemes the company's performance is compared to network loss targets. • Deviations from the targets result in either a penalty or a reward.	• The technical complexity of the loss incentive schemes is not high and depends on the complexity of the loss targets and the associated data requirements.	• The application of loss incentives is compatible with the current design of electricity transmission regulation. ACM currently applies loss incentive schemes for energy purchase costs (including network losses). • Network loss incentives are incorporated in the current yardstick regulation applied to the electricity distribution.	• Adopting an explicit loss incentive scheme (outside of the yardstick) for electricity distribution would likely require significant implementation efforts including changes in the regulatory framework.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Target Investment Incentives	Investment Incentives	• This instrument provides a financial incentive for specific investments that need to be prioritised. • For example, these can be investments driven by the energy transition such as the connection of renewable energy and the renewal and expansion of the electricity network.	• Formal criteria would have to be developed and a regulatory judgment would be necessary to review/ decide what investments qualify. • Due to the small number of regulated electricity network companies in the Netherlands, the use of such investment schemes would not be complex.	• The application of target investment incentives is compatible with the current regulatory system.	• The application of target investment incentives requires no fundamental change in the regulatory framework. • Adopting target investment schemes for the TSO and DSOs would require additional regulatory scrutiny. • The additional regulatory monitoring should be feasible given the small number of network companies in the Netherlands. • The estimated overall implementation effort is medium.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Environmental Incentives	Investment Incentives	• This instrument provides a financial incentive for the companies to achieve specific environmental targets related to integration of renewable energy. • The regulated companies are required to submit a plan setting out the envisaged actions involved in achieving the targets. • The planned actions are assessed by the NRA on base of the achievement of the targets, plan quality and implementation quality.	• A regulatory judgment is necessary to decide on the targets and the design of the incentive scheme. • Due to the small number of regulated electricity network companies in the Netherlands, the use of such investment schemes would not be complex.	• The application of environmental incentives is compatible with the current regulatory system.	• The application of environmental incentives requires no fundamental change in the regulatory framework. • Adopting environmental investment schemes would require additional regulatory scrutiny. • The additional regulatory monitoring should be feasible given the small number of network companies in the Netherlands. • The estimated overall implementation effort is medium.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Business Plan Incentives	Investment Incentives	• The purpose of this instrument is to encourage companies to submit high-quality (forward-looking) and robust business plans. • Companies that submit business plans that fail to meet minimum requirements and/or have poorly justified cost forecasts are penalised.	• While the design of the business plan incentive is not a complex exercise, the preparation of business plans and regulatory reviews is associated with significant complexity.	• In the current system network operators submit so called ‘investment plans’. • These plans are not used (and also in their current form cannot be used) to set the allowed revenues. • The application of business plans is compatible with the current electricity transmission regulation. • Setting the allowed revenues on basis of business plans is not compatible with the current electricity distribution regulation.	• The submission of business plans would require a significant increase in the level of data reporting and regulatory scrutiny. • While the design of the incentive is not a complex exercise, the preparation of business plans and regulatory reviews is associated with significant implementation effort. • The revenue setting in the current system for electricity distribution does not rely on forward-looking plans. The implementation of business plan incentives would require fundamental changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Revenue Adjustment Schemes	Investment incentives/cost recovery	• Revenue adjustment schemes provide ex-ante rules for the adjustment of the allowed revenues to account for uncertainty. • They can be used to account for the costs of investments that have not been envisaged at the beginning of the regulatory period.	• A regulatory judgment is necessary to decide on the cost drivers and the design of the adjustment scheme. • The technical complexity of such adjustment schemes would not be high.	• The application of revenue adjustment schemes is compatible with the current design of electricity transmission regulation. • The application of the scheme in electricity distribution would require changes in the regulatory framework.	• Depending on the design, the application of revenue adjustment schemes for electricity transmission and distribution would require an increase in the level of data reporting and regulatory scrutiny. • The implementation effort for electricity transmission depends on the chosen complexity but it is likely to be medium. • For electricity distribution the implementation would require changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Interim reviews / trigger mechanisms	Investment incentives/ cost recovery	• Interim reviews provide ex-ante rules to account for uncertainty and adjust the allowed revenues for the costs resulting from material changes in circumstances. • They help to reduce certain risks the network operators face.	• A regulatory judgement is necessary to decide on the specific design of the mechanism. • The technical complexity of the mechanisms would not be high.	• The application of interim reviews is compatible with the current design of electricity transmission regulation. • The application of interim reviews in the regulation of electricity distribution would require changes in the regulatory framework.	• Depending on the design the application of the interim reviews would require an increase in the level of data reporting and regulatory scrutiny. • For electricity transmission the implementation effort depends on the chosen complexity, but it is likely to be medium. • For electricity distribution the effort would be high as the implementation would require substantial changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Indexation / Quantity factor	Investment incentives/ cost recovery	• Indexation schemes and quantity factors provide ex-ante rules for the adjustment of the allowed revenues to account for changes in specific cost drivers during the regulatory period.	• A regulatory judgement is necessary to decide on the cost drivers and the design of the indexation scheme. • The technical complexity of indexation schemes and the use of quantity factors depends on the specific design.	• The application of indexation/quantity drivers is compatible with the current design of electricity transmission regulation. • The application of the scheme in electricity distribution would require substantial changes in the regulatory framework.	• Depending on the design, the application of indexation/quantity factors would require an increase in the level of data reporting and regulatory scrutiny. • For electricity transmission the implementation effort depends on the chosen complexity, but it is likely to be medium. • For electricity distribution the effort would be high as the implementation would require substantial changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Menu regulation	Efficiency/ investment incentives	• Under menu regulation a network operator is allowed to choose an option that optimises its financial position, i.e., maximises allowed revenues including the incentive impact. • The menu regulation incentivises network operators to disclose more accurate expenditure forecasts. • While this facilitates the regulatory assessment, the NRA should also develop its own CAPEX estimation for the purpose of menu regulation.	• The technical complexity of the mechanism is medium to high. • A regulatory judgement is necessary to decide on the specific design of the parameters.	• The application of menu regulation is compatible with the current design of electricity transmission regulation. • The application of menu regulation in electricity distribution would require substantial changes in the regulatory framework.	• The implementation effort of menu regulation is likely to be significant for electricity transmission and distribution. • For electricity distribution the implementation would also require substantial changes in the regulatory arrangements.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Incentive for controlling and prioritising Investments	Efficiency/ investment incentives	• The instrument focuses on specific groups of investments, for example network reinforcement stemming from the connection of renewable generators. • It consists of a cap on the investment volume and a penalty that applies if the cap is exceeded.	• The design and use of this incentive would not be complex. • A regulatory judgement is necessary to decide whether an investment qualifies for the scheme. • Due to the small number of regulated electricity network companies in the Netherlands, the use of such schemes would not be complex.	• The application of incentives to prioritise specific investments is compatible with the current regulatory framework.	• The application of such incentives requires no fundamental change in the regulatory framework for electricity transmission and distribution. • Adopting the incentives would require additional regulatory scrutiny. • The implementation effort would be medium.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
End-of-life incentive	Efficiency/ investment incentives	• End-of-life incentives aim to prevent the replacement of network assets that have reached the end of their regulatory lifetime but for which the technical condition is still good. • They provide remuneration for these assets for an additional number of years.	• A considerable regulatory judgment is necessary to decide whether an asset qualifies for this incentive, what would be the adjusted regulatory lifetime and what would be the appropriate level of remuneration. • For the reasons mentioned above the use of end-of-life incentives would be characterised by a high level of complexity.	• End-of-life incentives rely on substantial discretionary judgements to decide what assets qualify. • End-of-life incentives assume substantial flexibility in terms of periodic changes of regulatory lifetime. • For the reasons mentioned above the application of end-of-life incentives does not appear directly compatible with the current regulatory system.	• The application of end-of-life incentives requires amendments in the regulatory framework for electricity transmission and distribution. • Adopting such incentives would require substantial additional regulatory scrutiny and regulatory judgement. • The implementation effort would be significant.
Incentive for the provision of data	Sector coordination	• This instrument specifies data that is of major importance to market participants and sets deadlines for its publication. • It applies penalties for non-compliance with the deadlines.	• A regulatory judgement is necessary on the choice of data. • The design and use of this incentive would not be complex.	• The application of incentives for provision of data is compatible with the current regulatory framework.	• The use of the incentive would require no significant changes in the regulatory framework for electricity transmission and distribution. • The implementation effort is low.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Incentive for the achievement of the RES-E targets	Investment incentives	• The network companies are required to prepare a multi-year plan with actions for achieving the RES-E targets. • The NRA assesses the actions carried out by the companies and applies financial incentives.	• The design and use of this incentive would not be complex. • A regulatory judgement is necessary on the definition of data reporting. • Due to the small number of regulated electricity network companies in the Netherlands, the use of such schemes would not be complex.	• The application of the incentives is compatible with the current regulatory framework.	• The use of the incentive would require no significant changes in the regulatory framework for electricity transmission and distribution. • Adopting such incentives would require additional regulatory scrutiny. • The implementation effort is medium.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Stakeholder engagement incentive mechanism	Sector coordination	• The objective of this incentive is to encourage the network operators to improve their engagement activities. • Engagement activities mean how network operators understand and address the needs of stakeholders and how their input is used to improve network services. • This instrument provides network operators with a financial incentive on the scope, quality, and outcomes/impacts of their stakeholder engagement activities.	• The design and use of stakeholder engagement incentives would not be complex.	• The application of stakeholder engagement incentives is compatible with the current regulatory framework.	• The application of stakeholder engagement incentives would require no significant changes in the regulatory framework for electricity transmission and distribution. • Additional regulatory effort will be needed to evaluate companies' engagement. • The instrument can be easily implemented.

Instruments	Regulatory Area	Economic properties	Technical Complexity	Consistency / Compatibility	Administrative / implementation effort
Joint incentives	Sector coordination	• The purpose of this incentive is to encourage the companies to act jointly and align their activities in terms of planning, operation and innovation. • Examples could be to improve collaboration and innovation in deployment of new technologies or enhance asset and programme data exchange. • Performance evaluation typically includes both quantitative and qualitative metrics and applies a reward/ penalty scheme.	• While the design of the joint incentive is not a complex exercise, the practical use would require substantial consultation and coordination with the network operators.	• The application of joint incentives appears compatible with the current regulatory framework.	• The use of joint incentives requires no fundamental change in the regulatory framework for electricity transmission and distribution. • Adopting such incentives would require additional consultation and coordination with the network operators. • Despite the small number of network companies in the Netherlands, the implementation effort can be significant.

5 GERMANY

5.1 Background Information

The electricity sector in Germany is characterised by a phase-out of nuclear power generation and a significant shift of electricity generation from fossil fuels to renewable energies (in particular wind and solar). Currently, renewables represent around 50% of the power capacity and contribute to 30% of power generation. The German government intends to increase the share of renewable energy to at least 80% by 2050.

The German electricity transmission network is owned, operated and developed by four TSOs: TenneT, Amprion, 50Hertz and TransnetBW. Transmission voltages are 380kV and 220 kV. Electricity distribution in Germany is conducted by around 880 DSOs of various sizes (majority in municipal ownership).

The transition towards a renewable energy economy leads to technical and economic challenges. With the exemption of offshore wind that feeds into the transmission network, producers of renewable energy are connected to the distribution network. The German electricity networks will need to accommodate the large volumes of fluctuating, renewable power in the future. There is a need to build a more flexible system where generation and consumption can both deal with short-term variability and limited predictability. The regulation is therefore essential to encourage the network investments.

The Federal Network Agency (Bundesnetzagentur, BNetzA) is responsible for the regulation of the network operators. The general framework for electricity and gas network regulation is largely determined by EU legislation and the German Energy Industry Act. The major rules for price regulation of network operators are set out in a number of ordinances adopted by the German Government (updated several times until now). The Incentive Regulation Ordinance (ARegV), in conjunction with the Electricity Network Fees Ordinance (StromNEV) are the two most relevant regulatory documents.

Further details are contained in the justification of the specific decisions of the German Regulator.

5.2 Price Control Model

The electricity transmission and distribution networks in Germany are subject to incentive regulation, which takes the form of a revenue cap that a network operator can earn over the regulatory period. The length of the regulatory period is 5 years. The electricity distribution and transmission companies are currently in the 3rd regulatory period (2019-2023).

In general, the regulatory framework applies an output steering approach. It sets goals that the network operators should achieve rather than prescribing how to achieve them and what tasks to carry out. Reporting duties and data submission requirements are set out in the secondary legislation and Energy Industry Act. Examples include the obligation to connect customers, provision of reliable electricity transmission and distribution services, requirements to manage congestion by market and network measures.

5.3 Revenue Setting / Cost Assessment Principles

The allowed revenues (revenue caps) of the transmission and distribution network operators are set in advance for the entire upcoming regulatory period. They aim to recover the efficient operating and capital costs necessary to provide the regulated network services. The regulated companies are encouraged to seek solutions to improve efficiency as they can retain the efficiency gains for the remaining part of the regulatory period.

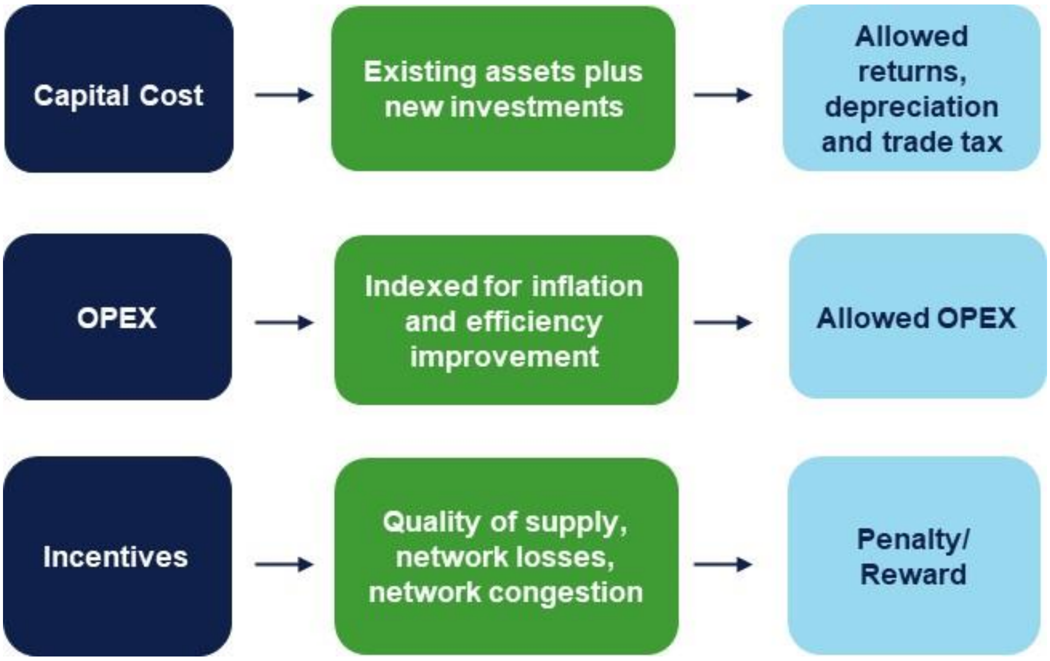

Figure 3: Simplified Representation of the Revenue Setting

Source: DNV

5.3.1 Initial Cost Review

Before the start of a regulatory period, the NRA determines the initial levels of the revenue cap for each network operator. For this purpose, the NRA conducts a comprehensive cost review of the reported historical costs in the base year (year t-3, i.e. three years before the start of the regulatory period).

First, it checks whether the reported costs belong to the provisions of the regulated network services. The NRA can exclude specific cost positions such as cost for marketing, advertising etc. which are not specifically related to carry out the activity of electricity network service.

Second, it validates the conversion of the data from the financial statements and conducts initial cost assessments in order to establish the regulatory cost block relevant for the initial revenues (starting revenue level). The latter is in particular relevant for the determination of capital costs and requires the recalculation of asset values and depreciation for regulatory purposes (see chapter 5.3.3). There are differences between asset values / depreciation used in the financial and regulatory accounting. The differences are caused by the asset valuation concepts and asset life periods. The regulated companies provide data on the regulatory asset values and depreciation in their submissions while the NRA validates the reported numbers

Third, it separates the permanently non-controllable costs within the initial revenue cap. The permanently non-controllable costs are explicitly defined by the NRA and include *inter alia* concession fees, operating taxes, payments for the use of upstream network levels, labour costs of work council activities.

5.3.2 Operating Costs

The OPEX estimation applies an indexation approach. This means that the NRA does not rely on explicit cost projections for the years of the regulatory period. The allowed annual OPEX (excluding the permanently non-controllable costs) is rather set by a simple indexing by inflation and efficiency improvement factors (individual and general X factors set by the

NRA, see chapter 5.4.1) whereas the starting point is based on the company's actual cost in the base year. The inflation is measured through the Consumer Price Index from t-2 and based on data from the Federal Statistical Office Destatis.

The permanently non-controllable costs are adjusted annually within the regulatory period. In practical terms, the NRA replaced the figures contained in the initial revenues by either using their planned values or their actual values from year t-2 (i.e. two years before the adjustment year). For example, actual values from year t-2 are used for the concession fees and operating taxes. Furthermore, the permanently non-controllable costs are not subject to efficiency/productivity targets and inflation adjustments. The remaining costs are considered overall controllable.

5.3.3 Capital Costs

The capital costs used in the regulatory revenue setting include depreciation, return on equity, return on debt, and trade tax.

The NRA does not apply a WACC concept to establish the return on assets. The allowed return is set separately for equity and debt.

Furthermore, the NRA applies different return on equity and depreciation for assets acquired before 1 January 2006 and after 31 December 2005. It is caused by the co-existence of two valuation concepts implemented with the regulatory accounting reform in 2006. Until the end of 2005 the German regulation had been using the operating capital maintenance concept. Accordingly, the equity funded portion of the asset base was valued at replacement costs and earned a real rate of return, while the rest was valued at the historical purchase costs and yielded a nominal rate of return. Starting from 2006, the country moved to the financial capital maintenance concept. Accordingly, the asset base is valued at historical purchase costs and yields a nominal rate of return. In order to ensure consistent treatment of the capital costs resulting from the CAPEX spend before and after 2006, it was decided to apply both concepts.

5.3.3.1 Return on Debt

The allowed return on debt is set in line with prevailing market conditions. The NRA may allow the actual debt interests incurred by the regulated company if the company can prove that they do not exceed the market interest rate for bank and industry loans. In order to make informed decisions, the NRA establishes a reference level for debt return. The reference level is calculated on the basis of the 10-year average of the annual current yields of the government bonds (10 years maturity) plus a premium based on the 5-year average return of corporate bonds (credit rating BBB- and maturity between 7 and 143 years).

5.3.3.2 Return on Equity

In order to determine the return on equity the NRA sets the equity base (Equity Necessary for Operation) and the allowed rate of return.

Equity Necessary for Operation

The Equity Necessary for Operation II (ENO II) is set for the first year of the regulatory period on the basis of reported data from year t-3, the base year (three years before the start of the regulatory period). This is illustrated in the following Figure 4. To start, the NRA calculates first the Assets Necessary for Operation II (ANO II) as the sum of:

- the net value of tangible assets acquired before 1 January 2006 at their replacement value multiplied by the equity share capped at 40%.[20] The determination of equity share is explained below.

[20] Net asset value is established by deducting the cumulated regulatory depreciation from the gross asset value. The replacement value is determined by indexing the historic cost by a set of index numbers differentiated by asset groups.

* the net value of tangible assets acquired before 1 January 2006 valued at historical purchase cost multiplied by the debt share which is one minus equity share
* the net value of tangible assets acquired after 31 December 2005 at historical purchase cost
* the balance sheet value of financial assets. The NRA examines the need of these assets for the provision of the regulated services. Typically, it does not allow to include them in the ANO II.
* the balance sheet values of the current assets. The NRA examines the level of the current assets by examining their individual components and can set norms for their recognition in the ANO II.

The ENO II is determined by deducting from the ANO II the interest-free liabilities and interest-bearing liabilities.[21] It is split then into three portions:

* ENO II lower than 40% for assets that have been acquired before 1 January 2006
* ENO II lower than 40% for assets that have been acquired after 31 December 2005
* ENO II in excess of 40%

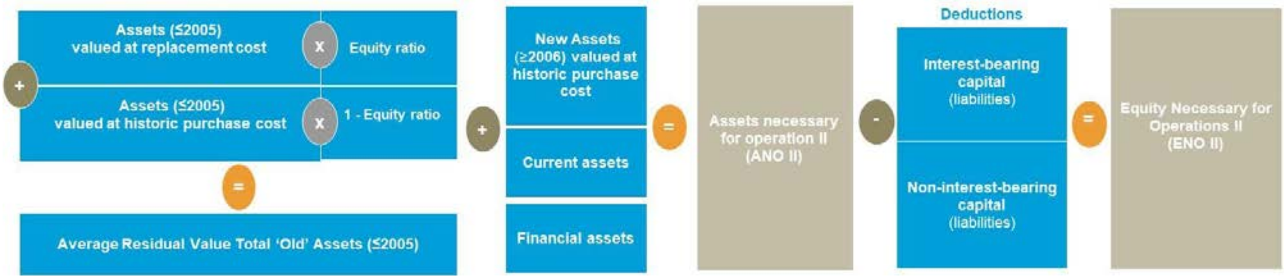

Figure 4: Determination of the Equity Necessary for Operation (ENO)

Source: DNV

For each of these equity portions the NRA allows different level of return as explained below.

The calculation of the equity share mentioned above for the establishment of ANO II follows three specific steps. The NRA first determines the Assets Necessary for Operation I (ANO I) as the sum of:

* net value of tangible assets acquired before 1 January 2006 at historical purchase cost
* net value of tangible assets acquired after 31 December 2005 at historical purchase cost
* the balance sheet value of financial assets
* the balance sheet values of the current assets.

In a second step the NRA calculates the Equity Necessary for Operation I (ENO I) by deducting from the Assets ANO I the interest-free liabilities and interest-bearing liabilities. Finally, the ENO I is divided by the ANO I to determine the equity share.

21 Interest-free liabilities include tax provisions, pension provision, accounts payables, capital contributions from third parties (e.g. payments for connection charges).

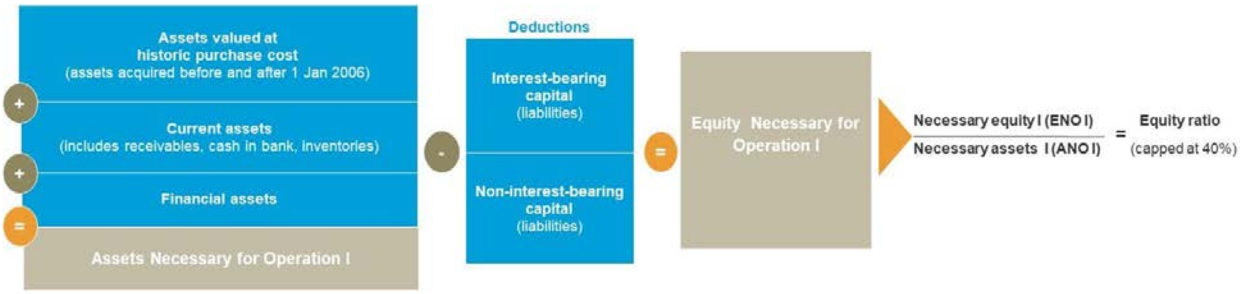

Figure 5: Determination of the Equity Share

Source: DNV

Allowed Rate of Return

The allowed return on equity is set separately for assets acquired before 1 January 2006 and those acquired after that date. Specifically, the NRA applies the following rules:

- The asset portion ENO II lower than 40% for assets that have been acquired before 1 January 2006 earns real (excluding inflation) pre-tax return (before corporate tax and after trade tax) [22]
- The asset portion ENO II lower than 40% for assets that have been acquired after 31 December 2005 earns nominal pre-tax return (before corporate tax and after trade tax)

In order to estimate the rate of return on equity, the NRA applies the Capital Asset Pricing Model (CAPM). The risk-free rate of return is set equal to the 10-year average of the annual current yields of bonds issued by domestic issuers published by the Bundesbank. The market risk premium is set using the DMS database (Dimson, Marsh, Staunton). Equity beta is estimated using an international sample of reference companies with specific characteristics. The NRA applies the same parameters for electricity transmission and distribution.

The rate of return that can be earned by the asset portion ENO II in excess of 40 % is set according to the 10-year average yield of selected public (1/3 weight) and corporate bonds (2/3 weight) issued by domestic institutions.

5.3.3.3 Trade Tax

The trade tax is charged on equity return. The effective tax rate is equal to the product of Tax Rate (*Hebesatz*) and Tax Index (*Steuermesszahl*). The trade tax may vary between the regulated companies as the Tax Rate differs from region to region.

5.3.3.4 Regulatory Depreciation

Regulatory depreciation is straight-line and is established according to pre-defined asset lifetimes for the specific asset categories in the network set for regulatory purposes.[23] As already explained above assets are treated differently depending on whether they were acquired before 1 January 2006 and after 31 December 2005. Depreciation of the assets acquired before 1 January 2006 is calculated as the sum of:

- Depreciation of these assets valued at replacement value multiplied by the equity share capped at 40%, and
- Depreciation of these assets valued at valued at historical purchase cost multiplied by the debt share which is one minus equity share.

22 Technically, the return is increased so that the corporate tax payments can be met from the pre-tax WACC.

23 Asset life for regulatory purposes differs from the asset life as specified in the German Commercial Code. The asset lifetimes for regulatory purpose are set out in an Appendix of the Ordinance on Network Charges.

Depreciation of the assets acquired after 31 December 2005 is set on the basis of the historical purchase cost.

5.3.4 Output-Based Incentives

In addition to the operational and capital costs described above, a portion of the allowed revenues of electricity transmission and distribution activities is derived from regulatory incentives linked to the achievement of specific objectives, such as improvements in the quality of supply, network losses etc. (see section 5.4).

5.3.5 Revenue Adjustment

The revenue caps (allowed revenues) for electricity transmission and distribution activities are adjusted annually within the regulatory period.

The adjustment pertains to inflation, general productivity growth and company-specific efficiency improvement targets. In addition, the rewards/penalties resulting from the incentive schemes are added / subtracted from the allowed revenues (see section 5.4).

Furthermore, the adjustment includes the annual effect of the regulatory account. The regulatory account covers *inter alia* differences in capital costs (resulting from divergence between planned and actual investments) (see sections 5.5.1 and 5.5.2), changes in the permanently non-controllable costs and differences between the allowed and actual revenue (resulting from divergence between planned and actual quantities). The annual balance of the regulatory account (of each year) is spread on an annuity basis over three subsequent years following the year of its calculation and incorporated in the allowed revenue.[24]

Finally, the allowed revenue can also be adjusted in case of unexpected events leading to a large negative impact on the regulated companies that cannot be endured by those companies (hardship provision).

5.4 Efficiency Incentives

During the regulatory period the allowed revenues of the network operators are adjusted annually by the anticipated efficiency increase requirements set by the NRA. The companies are encouraged to seek efficiency improvements and reduce their costs below the regulatory caps as they are allowed to retain the efficiency gains.[25]

The efficiency incentives are established by the application of efficiency and productivity analysis, and the application of norms / targets.

5.4.1 Application of Efficiency and Productivity Analysis

Efficiency Analysis for Electricity Distribution

The efficiency of the DSOs is estimated by a comparative analysis (benchmarking) of 204 DSOs.[26] The efficiency of the transmission network companies is determined by a comparative analysis in an international sample and the application of reference network analysis.

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24 The time lag between the time of the occurrence and the time of the revenue adjustment is accounted for by an upward correction of the balance with the risk-free rate used for the calculation of the allowed rate of return on equity.

25 The retention is limited to the regulatory period (5 years). For the following regulatory period, the NRA resets the allowed revenue starting from the cost incurred in the base year (t-3) and following the principles described in section 5.3.

26 Small DSOs (≤ 30,000 connected customers) can decide not to participate in the efficiency analysis. In this case their efficiency score is uniform and is equal to the weighted average of the individual efficiency scores from the efficiency analysis in the last regulatory period.

The efficiency analysis (benchmarking) is conducted before the start of the regulatory period. The analysis uses the total costs (including operating and capital costs but excluding the permanently non-controllable costs) of the network operators in the base year. The advantage of the total cost specification is that it accounts for the trade-offs between the costs of different activities/areas made by the DSOs. The analysis derives efficiency scores for each DSOs, which are then converted to efficiency improvement targets (individual X factors).

The NRA applies Data Envelopment Analysis (DEA) and Stochastic Frontier Analysis (SFA) techniques to estimate the efficiency of the DSOs.[27] The output parameters reflect suitable exogenous cost drivers and the operating environment of the network operators. The output parameters are selected using technical and economic analyses. The applied output parameters in the 3rd regulatory period include metering points, length of cables/overhead lines by voltage level, peak load by voltage level, installed generation capacity at extra high/high voltage and at low/medium voltage.

Since the 3rd regulatory period, the DSOs who have been identified as "super-efficient" earn an efficiency bonus of up to 5% for the duration of the regulatory period.

The NRA uses several measures to mitigate the incorrect estimations of efficiency scores. As mentioned above two efficiency estimation techniques are applied, one deterministic and one stochastic. The techniques are used with two specifications of the cost inputs. The first specification takes the cost reflecting reported figures in the regulatory accounts (see section 5.3.3). The second specification replaces the capital cost from the regulatory accounts with standardised capital costs. The standardised capital costs are calculated as annuities and aim to remove the differences from companies' asset age.

The NRA calculates for each DSO four efficiency scores (two specifications of the cost inputs and two efficiency estimation techniques). The final efficiency score is equal to the highest one from the four techniques applied – this is also referred to as the best of four principle. The efficiency score is floored at 60 percent for DSOs whose efficiency values are less than 60 percent from the efficiency analysis.

Efficiency Analysis for Electricity Transmission

The efficiency of the TSOs is determined with the help of reference network analysis. A reference network is a synthetic network developed using engineering methods that apply commonly accepted planning principles and take into account the specific technical and geographical characteristics of the regulated companies.

The efficiency improvement potential of a TSO is estimated by comparison with its reference network. The TSO with the smallest distance to its reference network forms the benchmark (efficiency value of 100 percent).

General Productivity Analysis

In addition, the NRA applies an explicit requirement for productivity improvement (general X factor) to TSOs and DSOs. The productivity improvement is associated with the "frontier shift" and is imposed in addition to the individual efficiency improvement requirements ("catch-up effect"). The frontier shift characterises the ability of even the most efficient network operators to improve their efficiency over time because of technological change.

Conceptually, the productivity improvement is incorporated into a composed factor (X gen) which also combines inflation components. Mathematically, X gen is specified as (ΔFP - ΔINF). ΔFP represents the difference of the productivity

[27] DEA is a non-parametric approach based on linear programming, i.e. no functional relationships between input and output factors needed.
SFA is a parametric model that applies regression analysis with adjustments to consider stochastic noise. The classical (ordinary least-square) regression line cuts across the observations by minimising the sum of the squares of the distance (residual) between the line itself and each of the data points in the sample. This line can be shifted towards the best performing company (frontier) and can measure the efficiency of the induvial company in comparison with the best performing company (corrected ordinary least square). SFA adjusts additionally the frontier by decomposing the distance in "true efficiency" and "random noise" effects.

improvement in the regulated industry and the total economy. ∆INF is the rate of change in input price index for the economy and rate of change in input price index for the regulated network industry.[28]

The productivity improvement is estimated by the NRA through an analysis of the productivity historical development for the regulated network industry and general economy. The NRA uses long-term series (e.g. 2006-2017 for the third regulatory period) and two mathematical techniques, Tornqvist analysis and Malmquist analysis.[29]

The allowed revenues are adjusted each year of the regulatory period with the individual and general X factors. By doing so, the required efficiency and productivity improvements are transferred to network users. The regulated companies can retain all cost savings below the allowed revenue level.

5.4.2 Regulatory Incentives for Reduction of Network Losses

The revenue cap of the DSOs is adjusted annually through an explicit term (volatile cost element) for network losses.

As the costs of network losses from the base year are already incorporated in the allowed revenues, the NRA sets incentives by annually adjusting these costs to their allowed (reference) level. Accordingly, the adjustment in a given year is equal to the difference between the determined costs of network losses in the base year and the allowed cost of network losses in that year of the regulatory period.

That allowed annual costs of network losses are calculated by multiplying the allowed loss quantity with a reference price. In the current regulatory period, the allowed loss quantity for each DSO is set equal to the allowed quantity in the base year and is kept for each year of the regulatory period. In contrast, the reference price is reset every year and is calculated as the weighted average of historical wholesale prices (1 July t-2 /30 June t-1).

Depending on the actual costs of network losses, network operators can incur efficiency gains/rewards (actual costs are lower than allowed costs) or efficiency losses/penalties (actual costs are higher than allowed costs).

5.4.3 Quality of Supply Incentives

The NRA applies an incentive scheme for quality of supply in electricity distribution networks, SAIDI (System Average Interruption Duration Index) for the low voltage networks and ASIDI (Average System Interruption Duration Index) for the middle voltage networks. The incentive scheme covers the unplanned interruptions longer than three minutes caused by events within the responsibility of the DSOs. SAIDI provides a measure for the average time that customers are interrupted.[30] ASIDI Average System Interruption Duration Index (ASIDI) and provides a measure for the average time that customers are interrupted.[31]

The DSOs are required to provide information on the time, duration, extent and cause of supply interruptions in their networks.[32]

28 The formulation of the factor in this way goes back to the theoretical work of Bernstein and Sappington 1999.

29 The Tornqvist Index measures the productivity change over time. Productivity of a company is measured by the quantity of output produced per unit of input. In the case of a single-output and single-input (partial factor productivity) this would simply be the ratio of its output and input quantities. When multiple inputs and/or multiple outputs are involved (total factor productivity), weights are added to the output and input quantities.
The Malmqvist Index is able to decompose the productivity change into relative efficiency change (firms getting closer to the frontier) and technological change (frontier shift). The Malmqvist Index measures the productivity change between two data points by calculating the ratio of the distances of each data point relative to a common technology. It can apply DEA or SFA.

30 It is calculated by dividing the total customer interruption duration by the total number of customers. Customer interruption duration is defined as the aggregated time that all customers were interrupted

31 It is calculated by dividing the sum of all interruption time periods multiplied by the capacity (apparent power) of the disconnected transformers, by the total capacity (apparent power) of transformers connected to the distribution system. Customer interruption duration is defined as the aggregated time that all customers were interrupted

32 Furthermore, additional data such as the yearly peak load (kW), geographical area (km²) for middle voltage, supplied area (km²) for low voltage, network length (km), number of customers, and number of connection points have to be submitted to the NRA.

The NRA sets reference values for SAIDI and ASIDI. The reference value for ASIDI for the middle voltage networks is set for each DSO individually and is calculated by using a mathematical function. The function connects ASIDI and load density. The NRA uses historical data of load density to set induvial reference values for ASIDI for each DSO. The reference value for SAIDI for the low voltage networks is uniform for all DSOs and is set equal to the average historical values for SAIDI.

The difference between the reference level and the actual SAIDI (low voltage level) and ASIDI (middle voltage level) of a network operator is transformed into a monetary reward or penalty (Q factor) by multiplication with a price of quality per unit and the number of customers. The price of quality is determined by estimating the value of lost load (VOLL), For industrial consumers the VOLL is measured as the lost value of output reduction due to interruptions. For residential consumers the VOLL is measured as the lost value of leisure. In the current regulatory period, the NRA uses a uniform average value for all consumers (without differentiating between industrial and residential consumers) equal to 0.22 €/minute/user.

The revenue cap is adjusted with the Q Factor. The reward/penalty for quality performance is capped at 4 % of the allowed revenues (excluding permanently non-controllable costs).

5.4.4 Congestion Management Incentives

The NRA applies an incentive mechanism for the congestion management costs of the TSOs. The incentive mechanism sets a reference (target) value on the aggregate congestion management costs that applies jointly to the TSOs. The reference value is set by using a linear trend function based on the actual congestion management costs of the last five years.[33] If the actual costs are below the reference value, the four TSOs receive a joint reward. If the reference value is exceeded, there is a joint penalty. The financial effect is calculated as 6% of the difference between the reference value and actual congestion cost and is capped at €30 million / year.[34] The allocation of the joint reward/penalty to the individual TSOs follows a key which is agreed upon by the four TSOs.

5.5 Capex Integration / Investment Incentives

5.5.1 Electricity Transmission

In the current regulatory framework, the investments of the TSOs expected during the regulatory period are included in the allowed revenues via an explicit investment measure allowance (IMA).

IMA aims to allow for recovery of the cost of (expansion) investments during the regulatory period. Specifically, the allowed revenues are adjusted for the capital costs of the planned investments and a standard OPEX allowance.[35]

The revenue adjustment follows an application by the TSO which is subject to regulatory approval by the NRA. The approval is limited to the end of the regulatory period in which the IMA application has been submitted. If the application has been submitted after the base year for the following regulatory period, the approval is granted until the end of the following regulatory period.

Investments that qualify for IMA are defined in the regulatory framework and include *inter alia* investments in system reliability, interconnections with national and international networks and integration of renewable generation.[36]

33 The regulatory framework requires the NRA to adjust the calculated reference values with predetermined annual amounts.

34 Till the end of 2023 the financial effect is calculated as 12 % only of the positive difference and the cap is not applied.

35 The OPEX allowance is set equal to 0.2% of the investment costs (before decommissioning of the investment) and 0.8% of the investment costs (after decommissioning of the investment).

36 See Incentive Regulation Ordinance, paragraph 23.

The capital costs of an investment are calculated with the planned investment figures.[37] During the IMA approval period these costs are treated as permanently non-controllable costs and included in the allowed revenue. Differences between the IMA actual and planned figures are reconciled via the regulatory account (see section 5.3.5).

The residual value of the assets stemming from IMA are rolled over into the asset base for the first regulatory period after the year in which approval ends.[38]

The Incentive Regulation Ordinance states that the IMA mechanism will be abolished at the start of the fifth regulatory period (2029). The future mechanism is not decided yet.

5.5.2 Electricity Distribution

At the beginning of the third regulatory period (2019) the NRA introduced an explicit CAPEX adjustment factor to account for changes in the capital costs of the DSOs within the regulatory period. It adjusts the yearly allowed revenue of a DSO based on the differences between the capital costs in the base year and the planned capital costs in every year of the regulatory period.

The CAPEX adjustment factor has two components. The first one (deduction component) refers to the capital costs of the existing assets and reduces the yearly allowed revenue. It reflects the decrease of the capital costs compared to the base year, caused by the depreciation of assets during the regulatory period. The falling capital costs are taken into account by decreasing the capital costs included in the initial revenue cap.

The second component (addition component) accounts for the capital costs of new investments during the regulatory period and increases the yearly allowed revenue. The capital cost additions are included in the allowed revenues based on the planned figures for investments without a time-lag. The capital cost additions are not subjected to general and individual efficiency improvement factors in the ongoing regulatory period. They are only included in the regulatory efficiency analysis for the next regulatory period. Differences between the actual and forecasted investment figures are reconciled via the regulatory account (see section 5.3.5).

The OPEX associated with these investments is not included in the allowed revenue of the current regulatory period. It is only considered for the next regulatory period.

Each year the DSOs need to submit a request for approval of the CAPEX adjustment factor for the following year to the NRA. The NRA provides specific instructions on the required information that the regulated companies need to submit for the application of the capex adjustment factor.

5.5.3 Investment Monitoring

The NRA monitors the investment behaviour of the network operators and publishes key figures at regular intervals. The NRA is also authorized to require the TSOs to prepare and submit a report on their investment behaviour and to demonstrate to what extent their investments reflect the age and condition of their network assets, depreciation volumes and supply quality. The NRA can also require the TSOs to submit an analysis of the transmission interconnection including retrospective analysis of load/ utilisation, reliability and operation of the networks.

[37] The planned figures are the investment forecast figures prepared by the TSOs and submitted to the NRA in their IMA's applications.

[38] Residual value: Historic purchase cost minus cumulated depreciation up to the respective base year.

5.6 Innovation Incentives

Following the request of a network operator the NRA can include a special allowance for research and development costs in the revenue cap for a given year. The allowance can cover 50 percent of the costs for projects which are approved and promoted by the Federal or State Governments. The regulatory framework does not specify which types of projects may be considered for this allowance. Outside of the network regulation framework, there are various government programs supporting innovations in energy transition.

5.7 Regulation and Energy Transition

The energy transition in Germany brings regulatory challenges caused by the uncertainty of electricity demand, investment needs and technology development. This is amplified by the applied multiannual regulation that may lead to substantial divergence between costs and revenues.

In order to mitigate uncertainties and to address potential forecasting errors, the NRA adjusts the allowed revenue to ensure timely remuneration of network investments and reflect changes in the permanently non-controllable costs (see section). Furthermore, differences between the actual and planned investment figures are incorporated in the allowed revenue via the mechanism of regulatory account (see section 5.3.5).

In the context of the efficiency analysis the NRA reduces the downside risk for network operators by using the best-of-four-principle (two specifications of the cost inputs and two efficiency estimation techniques) when setting the individual efficiency targets. The efficiency score is floored at 60 percent for network operators whose efficiency values are less than 60%. The estimated inefficiencies are gradually removed from the allowed revenues in the regulatory period.

6 GREAT BRITAIN

6.1 Background Information

The three transmission networks operators in Great Britain are National Grid Electricity Transmission (NGET) for the network in England and Wales, Scottish Power Transmission Limited for southern Scotland (SP Transmission) and Scottish Hydro Electric Transmission for northern Scotland and the Scottish island groups (SHE Transmission).

The electricity system operation (ESO) was separated from National Grid Electricity Transmission (NGET) in April 2019 and the current price control is the first, standalone price control for the ESO operators.[39]

National Grid Electricity transmission (NGET) owns and maintain the high-voltage electricity transmission network in England and Wales. This system consists of approximately 4,500 miles of overhead line, over 900 miles of underground cable and over 300 substations. SP Transmission's network comprises 3700 kilometres of overhead lines and over 600 kilometres of underground cables. SHE Transmission owns and maintains the 132 kV and 275 kV electricity transmission network in the north of Scotland. The system comprises 5,334km of high voltage overhead lines, underground cables and subsea cables.

There are 14 distribution network operator (DNO) regions. These are managed by six network operators

Table 1: Great Britain – Distribution Network Operators (DNO)

No.	Distribution Network Owner	Distribution Network Operator (DNO)
1.	Electricity North West Limited (ENWL)	Electricity North West Limited
2.	Northern Powergrid (NPG)	Northern Powergrid (Northeast) Limited Northern Powergrid (Yorkshire) plc
3.	National Grid Electricity Distribution (NGED) (formerly Western Power Distribution)	Western Power Distribution (West Midlands) plc Western Power Distribution (East Midlands) plc Western Power Distribution (South Wales) plc Western Power Distribution (South West) plc
4.	UK Power Networks (UKPN)	London Power Networks plc South Eastern Power Networks plc Eastern Power Networks plc
5.	SP Energy Networks (SPEN)	SP Distribution plc SP Manweb plc
6.	Scottish and Southern Electricity Networks (SSEN)	Scottish Hydro Electric Power Distribution plc Southern Electric Power Distribution plc

Due to the changes to the energy landscape, the DNOs in Great Britain are transitioning to distribution system operators (DSO). They will therefore have obligations to not only carry out its existing functions but to take on some new ones. The NRA published a Position Paper (Ofgem 2019c) on the approach and regulatory priorities for setting out the tasks of a DSO. Some new tasks consist for example to consider the high expected increase of renewables, bi-directional flow electricity, consideration of the higher uptake of electric vehicles.

39 In this case study, we will focus on the price control for transmission network operation.

6.2 Price Control Model

The Office of Gas and Electricity Markets (Ofgem) is responsible for the regulation of the transmission and distribution of the electricity and natural gas networks in Great Britain. The current regulatory regime for electricity and gas transmission and distribution is called RIIO. RIIO stands for Revenues using Incentives to deliver Innovation + Outputs. RIIO-2 is the second set of price controls implemented under the RIIO model. This framework includes a number of incentives based on outputs. For RIIO-2, the outputs are centred on three primary goals – both for electricity transmission and electricity distribution. These are to:

- Meet the needs of the consumers and network users
- Deliver an environmentally sustainable network
- Maintain a safe and resilient network

Network companies are encouraged to operate and invest in their network activities to deliver these primary outputs. Within these primary outputs, specific targets are defined. These are explained in more detail in section 6.5.

Before the start of a regulatory period, the network operators submit their business plans which detail their approach on how they intend to meet these goals. The business plans play an important role in the revenue setting process. The RIIO framework includes a Business Plan Incentive (BPI) to encourage the companies to submit high-quality and robust business plans (see section 6.7.1).

The regulatory periods for electricity transmission and distribution under the RIIO framework are as follows:

Electricity Transmission

- RIIO-1-ET: 1 April 2013 – 31 March 2021 (8-year regulatory period)
- RIIO-2 ET: 1 April 2021 – 31 March 2026 (5-year regulatory period)

Electricity Distribution

- RIIO 1-ED: 1 April 2015 – 31 March 2023 (8-year regulatory period)
- RIIO 2-ED: 1 April 2023 - 31 March 2028 (5-year regulatory period)

This chapter presents the regulatory arrangements under RIIO-2 for both electricity transmission and distribution. Where there are differences between electricity transmission and electricity distribution, these are highlighted.

For electricity distribution the final determination for RIIO-2 price control were published in December 2022.

6.3 Revenue Setting and Cost Assessment

Under the RIIO price control, the allowed revenues are set on the basis of the business plans prepared by the companies and an ex-ante efficiency analysis of the NRA. The business plans provide a forward-looking strategy for the entire price control period and explain how the goals set out under the RIIO framework will be met. The business plans include supporting information, justifying the total expenditures (TOTEX) proposed by the companies to conduct their activities and deliver the outputs. TOTEX comprises CAPEX (load related, non-load related and non-operational) and operating expenditures (OPEX). Please see section 6.3.2 for details.

The RIIO framework is based on the 'building blocks approach to set the allowed revenues as shown in Figure 6. The allowed revenue should be sufficient to recover the efficient costs that the network operator incurs in providing its services. These costs are the OPEX and capital cost (depreciation and return on assets). A tax allowance is also included.

As illustrated in the figure, TOTEX is made up of fast money and slow money. Fast money is funded in the year incurred. It is equivalent to OPEX. Slow money is added to the regulatory asset base and is recovered over time through allowances for depreciation and return on assets. Slow money is equivalent to CAPEX. To determine the portion of slow and fast money, this is done by the capitalisation rates. For NGET the capitalisation rate is set at 85%, for electricity distribution specific capitalisation rates for each network operator is applied ranging from 65%-80%.

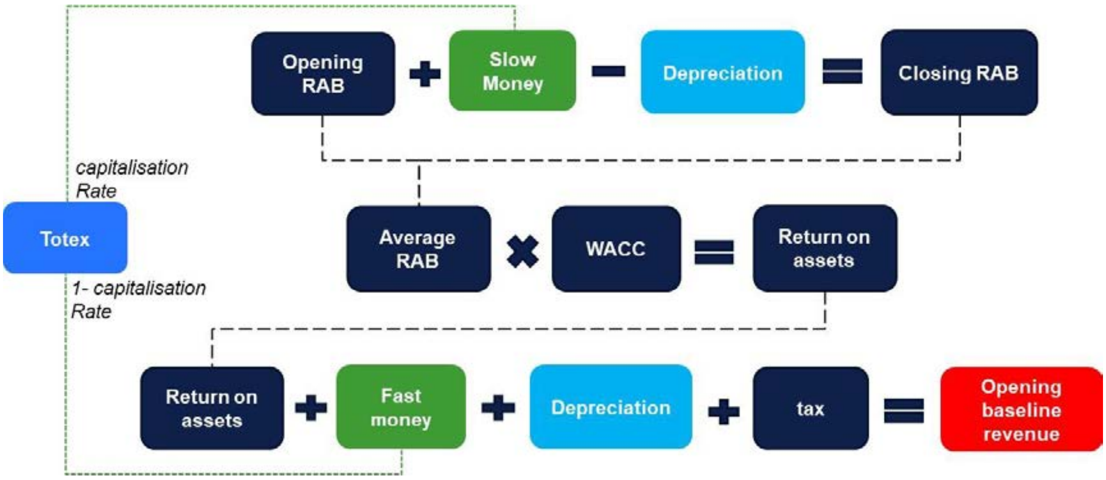

Figure 6: Overview of TOTEX building blocks

Source: Ofgem

6.3.1 Operating and Capital Costs for Regulatory Purposes

Operating Costs (OPEX)

The operating costs (OPEX) are associated with the day to day running of the regulated network business. These comprise direct OPEX and indirect OPEX. See section 6.3.2.1 for details.

Regulatory Asset Base (RAB)

The RAB of a network operator is the value upon which the network operator earns a return in accordance with the regulatory cost of capital and receives a depreciation allowance. The RAB of a company is determined by summing an estimate of the initial market value of its regulated asset base at privatization (2002) and all subsequent allowed additions at historical cost. Any asset disposals are deducted from the RAB. Furthermore, the RAB is indexed with the Consumer Price Index including Owner Occupiers' Housing Costs (CPIH).

Rate of Return

The allowed return on capital is the network businesses' Weighted Average Cost of Capital (WACC). The WACC is a "vanilla" WACC calculated on a real basis using:

- a pre-tax real allowed return on debt,
- a post-tax real allowed return on equity and
- a gearing percentage weighting (55% for transmission and 60% for electricity distribution operators).

The gearing percentage is fixed for the duration of the regulatory period; however, the cost of debt and the cost of equity are updated each year. This means that the WACC is updated each year. For the updating of the cost of debt a trailing average is used.[40] This is done as part of an annual iteration process (see section 6.8). The same methodology for determining the allowed return on debt and the allowed return on equity is applied for electricity transmission and distribution.

As the cost of debt used in the WACC calculation should be in real terms, the calculated nominal values are annually adjusted for inflation (deflated). The Consumer Price Index using the 5-year forecast by the Office of Budget Responsibility (OBR) is applied.[41]

The capital asset pricing methodology (CAPM) is applied to calculate to the return on equity.

Depreciation

The NRA sets the regulatory asset lives according to the average expected economic life of the related network assets. For electricity transmission and distribution, the depreciation asset lives are as follows:

- Pre-2002 assets have an asset life of 20 years: straight line depreciation
- Post 2002 assets have regulatory asset life of 45 years: straight line depreciation

Taxation

As the rate of return is a "Vanilla" WACC, i.e., without considering any taxes, an explicit allowance of corporation tax is included as part of the components to establish the allowed revenues.

6.3.2 Cost Assessment

To assess the business plans of the network operators, the NRA applies a combination of aggregated cost assessment (TOTEX Ordinary Least Squares (OLS) regression) and disaggregated cost assessment (activity-level analysis), both based on a comparative benchmarking. The TOTEX regressions are used only for electricity distribution and are explained in more detail in section 6.4.1.

The NRA adopts several methods to support the cost assessments including:

- Econometric benchmarking
- Historical trend analysis
- Activity level analysis
- Individual project reviews
- Technical / Engineering reviews
- Cost Benefit Analysis (CBA).

The above methods are applied in the cost assessment of a network operators' business plans. Depending on the type of cost, different methods are applied. In the following sections a summary of the type of methods used for the assessment of OPEX and for CAPEX is provided.

6.3.2.1 Cost assessment for OPEX (Disaggregated benchmarking)

For operating costs (OPEX), two main categories are distinguished:

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40 The averaging periods starts with a 11-year period (e.g., 2022: 01.11.2010 to 31.10.2021 (11- year period)), and then extended by one year as each regulatory year elapses. (e.g., 2023: 12-year period) and so on.

41 For RIIO-ED2, the cost of debt is determined using the same approach as for electricity transmission, as the price control periods are different the years applied for the averaging periods will however be different.

- Direct OPEX: These are network operating costs incurred in the day-to-day running of the network, for example, rectifying faults, repairs and maintenance activities.
- Indirect OPEX comprise:
  - Business Support costs (BSC): related to functions such as corporate governance, Information Technology & Telecoms, Procurement and HR
  - Closely Associated Indirect costs (CAI): costs for back-office functions involved in the construction and operation of network assets e.g., project management and network design, health & safety, vehicles & transport, network planning.

Electricity Transmission

For the direct OPEX, a historical trend analysis for both the transmission network operator and system operator is applied. The assessment is based on a comparison of a network operator's historical costs incurred during the first 6 years under RIIO-1 against the proposed spending during RIIO-2 for each of the cost categories.

For indirect OPEX, a joint assessment of both BS and CAI costs across electricity and gas transmission companies is used. The motivation for joint assessment is due to the commonality of their cost categories. The assessment is based on econometric modelling. The regression analysis uses (pooled) historical data (RIIO-1 period) and sensitivity checks based on forecast data to confirm consistency and applicability of the model.

Electricity Distribution

The table below presents the approach for the OPEX assessment (disaggregated benchmarking) used for electricity distribution. The NRA applies the analysis comprising of the electricity network operators operating in Great Britain.

Table 2: Overview of Disaggregated Benchmarking Analysis OPEX Electricity Distribution

Cost area NETWORK OPERATING COSTS (Direct OPEX)	Assessment technique	Benchmark	Time Period
Faults and Occurrences Not Incentivised (ONIs)	Regression analysis	Industry average	DPCR5+RIIO-ED1+RIIO-ED2[42]
Tree Cutting	Unit cost analysis	Industry median	RIIO-ED1+RIIO-ED2
Repairs, Inspections and Maintenance	Ratio benchmarking (unit costs)	Industry median	RIIO-ED1+RIIO-ED2
Smart Meter Rollout	Unit cost analysis	Industry median	RIIO-ED2
CAIs (network design and engineering, project management, system mapping, engineering management and clerical support, stores, network policy, control centre, call centre, wayleaves, operational training)	Regression analysis	Industry average	RIIO-ED1+RIIO-ED2

[42] DPRC Distribution Price Control: 2010- 2015. RIIO-ED1: 2015-2023, RIIO-ED 2: 2023-2028.

CAI Vehicles and Transport	Ratio benchmarking (together with Non-Operational Vehicles and Transport)	Industry median	RIIO-ED1+RIIO-ED2
Core Business Support (human resources and non-operational training, finance and regulation, insurance, fines and penalties, CEO)	Regression analysis	Average	RIIO-ED1+RIIO-ED2
Business Support IT & Telecoms	Ratio benchmarking (together with Operational and Non-Operational IT & Telecoms)	Industry median	RIIO-ED1+RIIO-ED2
Property Management	Ratio benchmarking (together with Non-Operational Property)	Industry median	RIIO-ED1+RIIO-ED2

Source: Ofgem 2022d

6.3.2.2 Cost Assessment for CAPEX (Disaggregated)

CAPEX are grouped into three main categories (applicable for both transmission and distribution):

- **Load-related (LR) CAPEX,** which relates to investments to expand current network capacity or to connect with new generation or demand sources.
- **Non-load related (NLR) CAPEX**, which relates to investments to maintain the health of the existing asset base, replacement CAPEX, asset refurbishment.
- **Non-operational CAPEX**, which relates to assets not directly connected to the network, but which support the general functioning of the business. There are three categories of Non-operational CAPEX: Property and Small tools, equipment, plant and machinery (STEPM); Vehicles and Transport and Information Technology and Information Technology and Telecoms (IT&T).

For load-related and non-load related CAPEX, firstly, a needs base review is conducted and second, the cost assessment. The needs base review is based on the companies' submission of the expected investments, the justification of investment, options considered, delivery and timings and project costs. For the load-related CAPEX, the companies also provide engineering justification papers and CBAs, which are submitted alongside the business plan for specific load-related projects. They should include details on the rationale and justification for why a particular solution was selected.

For the cost assessment, the NRA applies a range of techniques, including comparative cost assessments of proposed costs, unit cost analysis, assessments against the historical cost from RIIO-1 and market prices (tender cost), and engineering reviews.

For non-operational CAPEX related to smaller investments, the (disaggregated) cost assessment is as follows:

- **Property & STEPM**: detailed breakdown of forecast costs compared with historical spend over the previous regulatory period (RIIO-ET1 (2013 –2021) / RIIO-ED1 (2015-2023) period for each category.
- **Vehicles & Transport**: Historical trend model based on RIIO-ET1 / RIIO-ED1 of actual incurred costs for non-electric vehicles. For electric vehicles unit costs based on reviews of the companies' data are used.
- **Information Technology & Telecoms (IT&T):** Industry median benchmark ratio using modern equivalent asset value (MEAV) as a cost driver and comparison of RIIO-ED1 and RIIO-ED2 data. (MEAV is an asset which provides similar function and equivalent to the asset being valued / assessed).

6.4 Efficiency Incentives / Efficiency Analysis

As part of the overall assessment of costs, two types of efficiency incentives are used, namely:

- **Catch-up efficiency challenge** (see section 6.4.1): less efficient companies are encouraged to catch up to the most efficient companies (relevant for electricity distribution only), and
- **Ongoing efficiency challenge** (see section 6.4.2): reflecting an overall increase in productivity that even the most efficient companies are expected to deliver (applicable for electricity transmission and distribution).

The network operators are incentivised to out-perform the efficiency challenges, i.e., if its actual cost is lower than the allowed revenue, it will earn efficiency gains.

6.4.1 TOTEX Benchmarking (Electricity Distribution)

For the catch-up efficiency challenge, TOTEX benchmarking, and the disaggregated benchmarking cost assessment is applied for the electricity distribution companies.

To determine the catch-up efficiency target, benchmarking analysis based on the submitted (planned) costs in the business plans is conducted. It is based on assessing the network operators' forecast TOTEX in order to develop a view of the efficient costs that will form the proposed TOTEX for the regulatory period.

Non-controllable costs, i.e., costs that are outside of the control of the companies (like licence fees), are not included in the benchmarking analysis.

The NRA applies a combination of three aggregated TOTEX regression models and one disaggregated benchmarking model on activity-level (see Figure 7 below) to assess the costs proposed by the network operators. The analysis of the NRA is also supported by technical/engineering assessments in cases where costs are company or project specific.

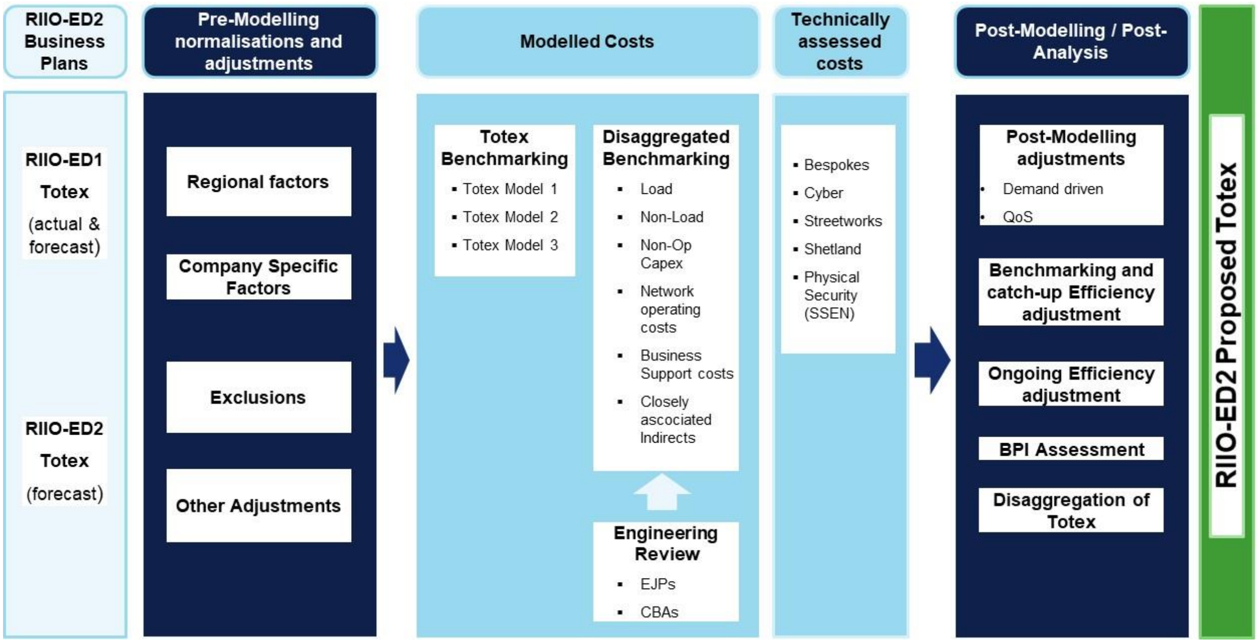

Figure 7: RIIO-ED2 cost assessment process – TOTEX Benchmarking
Source: Ofgem

To ensure costs are benchmarked on a comparable basis, the NRA first adjusts the costs. These adjustments fall into the four following categories as shown in the above figure:

- Regional factors: applied when operating in certain regions causes higher or lower costs. Companies may incur additional costs due to factors that are outside of their control and are either unique to, or disproportionately affect, the region in which they operate. The companies must justify any regional factor claims. An example is regional adjustments of labour cost
- Company-specific factors: applied when the characteristics of a particular network cause higher costs than others. An example is the nature of streets (increased cost / complexity of excavating and reinstating surfaces).
- Exclusions: applied when costs are inappropriate for comparative benchmarking because they are either only incurred by a small number of network operators, not explained by the cost drivers used, or their nature has substantially changed between RIIO-ED1 and RIIO-ED2.
- Other adjustments: relate to costs that are assessed separately.

The adjusted costs are referred to as "modelled costs" as shown in the figure and are used in three aggregated TOTEX regression models and the disaggregated activity-level models described in section 6.3.2.1 and 6.3.2.2. The modelled costs comprise approximately 96% of the forecast controllable costs on average, with the small remainder assessed using other, non-comparative, methods such as technical assessment

The NRA applies a 50% weighting on the three TOTEX regression models and a 50% weighting on the disaggregated model. The results from the three TOTEX models and the disaggregated cost model are used to estimate efficient costs for each company. This is then taken into account for the purpose of setting the allowed revenues after applying a catch-up challenge. The inefficient cost (catch-up efficiency challenge) is to be gradually improved over the regulatory period for each distribution network operator.

6.4.2 On-going Efficiency

In addition to the catch-up efficiency challenge, an ongoing efficiency challenge is applied to reflect the productivity improvements that even the most efficient company can achieve. The NRA considers that ongoing efficiency improvements are largely within a network operator’s control and can be generated in a variety of ways, for example by new approaches to staffing and delivery (contracting/outsourcing), collaboration between companies, employing new technologies, or effective investments in innovation.

To determine for ongoing efficiency for electricity transmission, it is based on the average historical improvement in efficiency for comparator sectors. The data from the EU KLEMS dataset is used. EU KLEMS is an industry level, growth and productivity research project. EU KLEMS stands for EU level analysis of capital (K), labour (L), energy (E), materials (M) and service (S) inputs.

For electricity transmission, an ongoing efficiency of 1.15% per year for CAPEX and 1.25% for OPEX per year is applied

For electricity distribution, the methodology to establish the ongoing efficiency is based on the following sources:

- Total Factor Productivity estimated from the EU KLEMs database.
- Historical performance/data of the network operators.
- Forward-looking productivity forecasts for the UK economy.
- Wider evidence on the scope for productivity improvements, e.g., as a result of innovation funding received by the network operators during RIIO-1.

For electricity distribution, an ongoing efficiency of 1% annually on TOTEX is applied.

6.5 Regulatory Incentives – RIIO Output Framework

The NRA stimulates TSOs and DSOs to deliver the three primary output categories mentioned in section 6.2 through:

- **Licence Obligations (LOs):** A set of minimum standards set in the licences of the companies. Failure to meet these standards could lead to enforcement action and penalties.
- **Price Control Deliverables (PCDs):** Directly associated with the revenue setting, there are no incentives or penalties applied. PCDs are outputs that are directly funded through the price control and where funding is not transferable to a different output or project.
- **Output Delivery Incentives (ODIs):** Drives service improvement through reputational (ODI-R) or financial (ODI-F) incentives that reward good performance and penalise bad performance.

Two additional mechanisms called the Use it or lose it (UIOLI) and uncertainty mechanism (UM) to supplement the LOs, PCDs and ODIs for specific outputs are applied. These mechanisms allow changes/adjustments to the revenues during the price control period. See section 6.8 for details.

6.5.1 Output Categories

Each of the three primary output categories consist of specific outputs as shown in Tables 3.

Tables 3: RIIO-2 Output Categories

1. Meeting the needs of consumers and network users

Electricity Transmission Output Name	Electricity Transmission Output Incentive
Energy Not Supplied	ODI-F
Timely Connections	ODI-F
SO:TO Optimisation Survey	ODI-F
Quality of Connections Survey	ODI-F
New Infrastructure Stakeholder Engagement Survey	ODI-R

Electricity Distribution Output Name	Electricity Distribution Output Incentive
Customer Satisfaction Survey	ODI-F
Complaints Metric	ODI-F
Time to Connect	ODI-F
Major Connection Incentives	ODI-F
Connections Guaranteed Standards of Performance	LO
Obligation to treat customers fairly	LO
Improving Service Standards for Vulnerable Customers	ODI-F
Annual Vulnerability Report	ODI-R

2. Delivering an environmentally sustainable network

Electricity Transmission Output Name	Electricity Transmission Output Incentive
Environmental Action Plan (EAP) and annual environmental report[43]	ODI-R and LO
Business carbon footprint	ODI-R
Environmental Scorecard	ODI-F
Insulation and Interruption Gas (IIG) leakage incentive	ODI-F
Visual amenity in designated areas provision	PCD, Uncertainty Mechanism (UM)
Net Zero and Re-opener Development	Use it or lose it (UIOLI)

Electricity Distribution Output Name	Electricity Distribution Output Incentive
Annual Environmental Report	ODI-R
DSO	ODI-F
Digitalisation Licence Obligation	LO
Technology Business Management (TBM) taxonomy for classifying digital/IT spend	ODI-R
Collaborative projects with other network operators to develop a new regulatory reporting methodology	ODI-R

3. Maintaining a safe and resilient network

Electricity Transmission Output Name	Electricity Transmission Output Incentive
Network Asset Risk Metric (NARM)	PCD and ODI-F
Cyber Resilience OT	PCD and Use it or lose it (UIOLI)
Cyber Resilience IT	PCD
Physical Security	PCD
Large Project Delivery (LPD)	PCD and ODI-F
Network Access Policy (NAP)	LO
Pre-Construction Funding (PCF)	PCD
Wider Works	PCD
Shared Infrastructure Schemes	PCD
Atypical Generation Connection Schemes	PCD
Atypical Demand Connection Schemes	PCD
Resilience and Operability	PCD

43 These are related to Output Deliverable Incentive (ODI) – Reputational and Licence Obligation. This means there is not incentive (award or penalty) applied. NGET is required to publish an Annual Environmental report on progress in achieving EAP commitments. Some EAP commitments include for example business carbon footprint reduction, sustainable resource use, recycling and reducing waste, reducing pollution.

Electricity Distribution Output Name	Electricity Distribution Output Incentive
Interruptions Incentive Scheme	ODI-F
Guaranteed Standards of Performance - reliability	LO
Network Asset Risk Metric	PCD, ODI-F
Cyber Resilience IT	PCD
Cyber Resilience Operational Technology	PCD
Smart Optimisation Output	LO

Financial incentives mechanisms (ODI-F) are mechanisms designed to reward or penalise performance for certain outputs. For example, for electricity transmission, the Energy Not Supplied (ENS) output has a financial incentive for under and over performance.

NGET is set a performance target of ENS in MWh. The performance target is a weighted average of ENSs from previous price control periods. 50% weighting on average ENS performance during RIIO-ET1 (2013-2019), 25% weighting on average ENS performance during TPCR4 (2007-2012), 25% weighting on average ENS performance during TPCR3 (2000-2006).

The incentive rate is set to the Value of Lost Load (VoLL) in 2018/19 prices (£21,000/MWh). The financial reward or penalty is calculated by multiplying the difference between actual ENS and the performance target by VoLL and applying the TOTEX incentive mechanism (TIM) sharing factor (see section 6.7.2).

An example of an ODI-F for electricity distribution is the Interruptions Incentive Scheme (IIS). The IIS is an incentive to improve overall reliability of the networks by reducing the number of customer interruptions (CI) and and duration of interruptions Customer Minutes Lost (CML)

CI is a measure of the number of customers, per 100 connected customers, that are interrupted on a DNO's network over the course of a year. For example, 50 customers interrupted out of a total of 100 connected customers would result in a CI of 0.5.

CML is a measure of the average number of minutes a customer is without power over the course of a year, per 100 customers. For example, if 50 out of 100 customers are without supply for 10 minutes in a year, this would result in a CML of 5.

Through the IIS, the distribution network operators are incentivised to reduce the impact of supply interruptions by exposing them to rewards and penalties for their interruptions performance against set targets.

6.6 Innovation Incentives: Network Innovation Allowance (NIA)

As part of the RIIO-2 output framework the Network Innovation Allowance (NIA) is a mechanism that allows funding to tackle the challenges associated with delivering net zero greenhouse gas emissions. The NIA is an amount that each network operator receives as part of its allowed revenues. It enables them to conduct innovative projects which they would otherwise not be able to undertake. The network operators include proposals in their business plans as to which innovative projects they would like to undertake.

The NIA funds research, development and demonstration trials that meet six specific eligibility requirements. Each innovation project must therefore comply with the following (applicable for electricity transmission and distribution):

- Facilitate energy system transition and/or benefit consumers in vulnerable situations
- Have the potential to deliver a net benefit to consumers

- Involve research, development or demonstration
- Develop new learning
- Be innovative
- Not lead to unnecessary duplication.

The type of projects eligible for NIA that are included in NGET's business plan include projects related to the energy transition and consumer vulnerability. For example, a proposal included projects for facilitating whole energy system innovation which includes a facility to trail (hydrogen and liquified natural gas) integration, electricity transport technologies and zero carbon generation technologies. It is a collaboration with other network companies.

The NRA has allowed NGET £49.3m of NIA funding. For SHET the NIA is £8m and for SPT it is £13.5m. The NIA covers 90% of the cost for the NIA projects over the RIIO-2 price control period. For electricity distribution, NIA of £68.4m to support innovation projects have been approved. Table 4 shows the amounts per DNO. The NRA has included a default level of companies' compulsory contribution equal to 10% of the project costs.

Table 4: Network Innovation Allowance: Electricity Distribution

Company	Network Innovation Allowance
Electricity North-West Limited (ENWL)	£8.4m
National Grid Electricity Distribution (NGED)	£18m
Northern Powergrid (NPG)	£7.5m
SP Energy Networks (SPEN)	£11.1m
Scottish and Southern Electricity Networks (SSEN)	£8.4m
UK Power Networks (UKPN)	£15m

Source: Ofgem

Furthermore, the RIIO-2 framework introduced a new instrument called the Strategic Innovation Fund (SIF) to fund projects with the potential to accelerate the transition to net zero emissions. See chapter 6.9.1 for further details.

6.7 Other Incentives

In addition to the output deliverable incentives and the network innovation allowance, the RIIO-2 framework includes a Business Plan Incentive (BPI) and a TOTEX Incentive Mechanism (TIM). These are described below.

6.7.1 Business Plan Incentive (BPI)

The purpose of the BPI is to encourage the development of ambitious, high-quality business plans, containing the information required for the NRA to undertake a robust assessment. The business plans set out the planned costs for the upcoming price control period. The plans also contain planned investments, with justifications and investment costs. The business plans are submitted to the NRA with supporting documents where necessary. The network operators may earn a reward or be penalised based on the NRA's assessment of the business plans. A business plan that fails to meet minimum requirements or have poorly justified cost forecasts results in a penalty. The NRA assesses the business plan based on the following four-stage approach:

- Stage 1: Minimum requirement: Qualitative assessment of business plans to ensure that they contain all of the minimally required information. This includes engineering justified papers and a CBA. Engineering justification papers set out the scope, costs and benefits for major projects or aggregated investment programs aimed at reinforcing the network or improving asset health. Business Plans will either pass or fail stage 1. If a plan has failed to meet the minimum requirements, an upfront penalty of 0.5% of allowed TOTEX will be levied. Companies whose plans fail stage 1 will not be eligible for a reward under stages 2 or 4 of the BPI and could potentially face a penalty under Stage 3 of the BPI.
- Stage 2: Customer Value Proposition (CVP): The CVP is a qualitative assessment of what additional value the business plan offers to consumers. For example, this could include the approach to include DSO activities (this is due to the changing role of the DNO to include DSO activities).
- Stage 3: Review of the cost forecasts: costs that are considered to be deemed as lower-confidence and poorly justified. This is classified as lower confidence costs. These costs are removed by the NRA from the network operator's forecasts through the cost assessment process. They are also subject to a penalty. The size of the penalty is 10% of the value of those poorly justified costs.
- Stage 4: Review of the cost forecasts: costs that are considered be high-confidence baseline cost. This is where the NRA can independently establish their own view of efficient costs for an investment. The resulting costs are classified as high confidence. An upfront reward is available to companies that submit forecasts lower than a benchmark based on the NRA's s own assessment.

6.7.2 TOTEX Incentive mechanism (TIM)

The TOTEX Incentive Mechanism (TIM) is designed to encourage companies to improve efficiency in the execution of their business plans. Furthermore, it ensures that the benefits of these efficiencies are shared with consumers. It also provides some protection to consumers from overspends as the costs of overspends are also shared between the companies and consumers. The TIM determines companies' exposure to under- or overspends compared to their TOTEX allowances. NGET is exposed to 33% of the difference between its actual and its allowed TOTEX and the consumer is exposed to the remaining 67%.

For electricity distribution a separate TIM for each distribution network operator is set. These range from 49.3% to 50%.

6.8 Cost and Revenue Adjustments

The RIIO framework contains so-called Uncertainty Mechanisms (UM). These allow adjustments to the revenues during the price control period to reflect, for example, cost changes that become clear during the price control period

The uncertainty mechanisms are applicable to electricity transmission and electricity distribution. There are five main types of uncertainty mechanisms:

1. **Volume drivers:** to adjust allowances in line with actual volumes, where the volume of work required over the price control period is uncertain, but where the cost of each unit is stable. For example, to manage the uncertainty associated with the amount of load-related CAPEX required to connect new generators and new demand customers to the transmission network.
2. **Re-opener mechanisms:** to allow the NRA to adjust a company's allowances when evidence and justification for doing so is provided by that company in a re-opener application. For example, a company can use the net zero re-opener to indicate to the NRA any material changes to its activities related to one of the key objectives of RIIO-2: supporting the delivery of net zero emissions.

3. **Pass-through mechanisms:** to adjust allowances for costs incurred by the network companies over which they have limited control, e.g., business rates and licence fees.
4. **Indexation:** to provide network companies protection against the risk that outturn prices differ from the forecasts that were made when setting the price control. This includes price difference stemming from inflation.
5. **Use-it-or-lose-it allowance (UIOLI):** to adjust allowances related to necessary activities or projects whose costs cannot be accurately estimated ex-ante. UIOLI provides the companies with allowances and flexibility in delivering activities, whilst protecting consumers by ensuring that unspent allowances are returned to consumers. The UIOLI is related to specifically to the development work on net zero projects for electricity transmission.

Any adjustments to the allowed revenues as part of the uncertainty mechanisms is done via the Annual Iteration Process (AIP). At the outset of the regulatory period, allowed revenues are calculated using approved forecast at that time based on the NRA's assessment of the business plan.

6.9 Regulation and Energy Transition

In line with the Decarbonisation Action Plan the RIIO framework continue attributing importance to each of the three elements of the policy trilemma (sustainability, security of supply and affordability). The key message from the NRA in respect to RIIO-2 especially for the upcoming regulatory period for electricity distribution is that emphasis is on investments to deliver value for consumers, safeguard security of supply to be better protected from geopolitical events and energy price shocks.

The investment plan will be for networks to focus on supporting the move away from a high dependence on imported fossil fuels, towards using more homegrown, cleaner, cheaper, and secure sources of energy. The potential of renewable energy sources require changes in the way energy is used and stored to gain their benefits and the price control set out by the NRA. For example, investments in the distribution networks have elements related to energy transition, customer protection and security of supply. This includes investments needed to increase grid capacity to power heat pumps to support the transition from gas boilers to renewable heating solutions and to support an increase the number of small-scale renewables connecting directly to the distribution grids. A targeted roll-out of 600.000 heat pumps by 2028 has been set. In addition, the investments also needed to improve the networks' resilience and response to extreme weather events and deliver improved customer service with additional protections for consumers living in vulnerable circumstances.

In respect to affordability, a new consultation has recently been launched called the Consumer Interest Framework to address current market conditions and to set-up the timely transformation of the energy system in consumers' interests. A set of short-term and longer-term strategic priorities have been defined and a proposed framework to support decision-making decisions with the core interests of energy consumers and addresses affordability and customer protection issues (Ofgem, 2022b).

6.9.1 Investment Incentives

The Network Innovation Allowance (NIA) for smaller scale research & development projects is one instrument of the RIIO regime aimed at facilitating the energy transition. The Network Innovation Allowance is explained in section 6.6.

The Strategic Innovation Fund (SIF) introduced in RIIO-2 aims to find and fund innovative large-scale projects with the potential to accelerate the transition to net zero emissions.[44] The following provides details of the strategic innovation fund.

[44] The Strategic Innovation Fund (SIF) is a new mechanism for funding large innovation projects, and it replaces the Network Innovation Competition (NIC) applied in RIIO-T1.

The SIF focuses on high-value innovation projects that would not otherwise be pursued by the companies as business-as-usual activities or via NIA funding. Projects that are eligible are focused around supporting the energy transition and/or support for vulnerable consumers. The projects funded through the SIF are projects of over £5m.

The SIF amounts to £450 million over the network price control period (RIIO-2).[45] In 2021, the first round of the SIF competitions took place. Each year, the NRA together with their partner UK Research and Innovation sets innovation challenges. In 2021 for electricity transmission, these challenges were for whole system integration, data and digitalisation, heat, and for zero emission transport. In 2022, the innovation challenges for transmission were to support a just energy transition, preparing for a net zero power system, improving energy system resilience, and accelerating decarbonisation of major energy demands.

The network operators (together with project partners if any) apply each year for the SIF, based on the innovation challenges set out. The process consists of three phases: After the discovery phase, the SIF may not progress to the alpha phase and so on. Progressing to the next phase depend on the results and outcome of the respective phase.

1. Discovery Phase (feasibility studies): The discovery phase defines the problem and the value in solving the problem. It also facilitates a common understanding of what energy consumers and network users need from the innovation and identifies any constraints that may impact the solution of the problem and options for the management of those constraints. The eligible projects have a duration of up to two months and the related SIF funding is capped at £150k.

2. Alpha Phase (experimental development): The alpha phase focuses on preparing and testing the different solutions to the problem that are identified during the Discovery Phase, ahead of any future large-scale implementation. It also tests the riskiest assumptions. The eligible projects have a duration of up to six months and the related SIF funding is capped at £500k.

3. Beta Phase (build, operation and/or demonstration): The beta phase focuses on the deployment of the solution to the problem. The duration of the beta phase depends on the scale and complexity of the solution deployed. The duration of beta phases is between six months and five years. The budgets start at £500k and might be capped.

Each project phase requires an application. Examples of innovation projects that are being funded via SIF range from technologies and approaches for the large-scale storage of heat to circuit breakers enabling the increasing amounts of power from offshore wind turbines.

6.9.2 Financeability

The network operators have a licence obligation to take all appropriate steps to maintain an investment grade credit rating. An investment grade credit rating signals a strong likelihood that the company will be able to meet its liabilities. Furthermore, the NRA must ensure that companies are able to finance the activities which they are legally obliged to carry out. As part of the revenue setting process, the NRA conducts a financeability assessment to ensure that a notionally efficient operator can generate sufficient cash flows to meet its financing needs.

45 The amount also includes funding for SIF projects for electricity and gas transmission, gas distribution & ESO. Electricity distribution can participate from 2023.

7 ITALY

7.1 Background Information

Italy plans to accelerate the transition from traditional fuels to renewable energy sources (RES) through a gradual phasing out of coal and natural gas. In 2021, around 36% of total energy demand was met from RES (including hydro, photovoltaic, wind, bioenergy and geothermal).

In January 2021, the government published the Italian Long-Term Strategy on Reducing Greenhouse Gas Emissions (MASE, 2021). This document indicates that renewable energies are expected to make up 80–90% of primary energy consumption by 2050. The increase of intermittent RES will require new flexibility resources for the electricity system as well as an important upgrade of transmission and distribution networks.

The transmission network in Italy is operated by Terna. The length of the transmission network amounts to about 75,000 km of lines and includes 26 interconnections with other countries.

The length of the electricity distribution network is approximately 1,280,000 km. There are about 125 electricity distribution network operators. Four of them are large and have more than 500,000 connection points, these are e-distribuzione (Enel group), Unareti (A2A group), Areti (Acea group) and Ireti (Iren group). The company e-distribuzione is by far the largest distribution network operator, with a share of 85.5%.

The Italian Regulatory Authority for Energy, Networks and the Environment (Autorità di Regolazione per Energia Reti e Ambiente, ARERA) is responsible for the economic regulation of electricity transmission and distribution.

7.2 Price Control Model

The current price regulation for electricity distribution is based on two types of regulatory regimes. Electricity distribution companies with at least 25,000 connection points are subject to the so-called “individual regime”. For the other companies the so-called “parametric regime” applies. According to this methodology, the allowed OPEX and CAPEX are set based on quantities such as the distributed energy and user density (for OPEX) and the age of the networks (for CAPEX). For the purposes of the analysis, we focus on the individual regime.

According to the “individual regime”, the electricity transmission and distribution networks are regulated using a hybrid approach, combining a cap (applied to the OPEX) and cost-of-service (rate-of-return) regulation (applied to the CAPEX). Under the cost-of-service regulation, network operators are allowed to recover the CAPEX of providing services. This creates limited incentives for ongoing efficiency improvements and revealing efficient CAPEX. This approach has low financial risk for the regulated companies, however the incentives to improve efficiency are low as well. The cap regulation approach applied to OPEX puts a stronger emphasis on the use of efficiency incentives (see section 7.3.1 and 7.4.1).

The current (fifth) regulatory period (called NPR) applied to electricity transmission and distribution extends over eight years and is divided into two subperiods referred to as NPR1 (2016–2019) and NPR2 (2020–2023). This allows the NRA to review, and if necessary, to update all the regulatory arrangements between the subperiods.

Overall, the NRA regulates with mechanisms using performance incentives linked to the achievement of targets set on specific outputs. Examples include the mechanisms for OPEX efficiency improvement (transmission and distribution network), improvement of quality of supply (transmission and distribution network), increase of transmission capacity (transmission network) and enhancement of network resilience (distribution network).

The NRA is currently in the process of reviewing the regulatory framework. The NRA intends to gradually implement a TOTEX approach to set allowed revenues (Regolazione per Obiettivi di Spesa e di Servizio (ROSS)). The current regulatory framework places emphasis on efficiency incentives only for OPEX. Since there are substitution effects between OPEX and CAPEX, the companies can adopt a strategy to increase spending in CAPEX in order to appear efficient in terms of the OPEX. The current review of the NRA aims to remove the existing CAPEX bias and to extend the incentives towards total cost. The process is still ongoing, and the new regulation (for electricity transmission and distribution) is expected to commence from the new regulatory period in 2024.

7.3 Revenue Setting / Cost Assessment Principles

The allowed revenue for electricity transmission and distribution is set for the years of the regulatory period. It is based on the information submitted by network operators that is checked by the NRA for sufficiency and consistency. The allowed revenue includes allowed operating costs and capital cost (depreciation and return on assets). The allowed revenue is also adjusted annually by rewards/ penalties resulting from performance incentives.

The following figure presents an overview of the revenue setting.

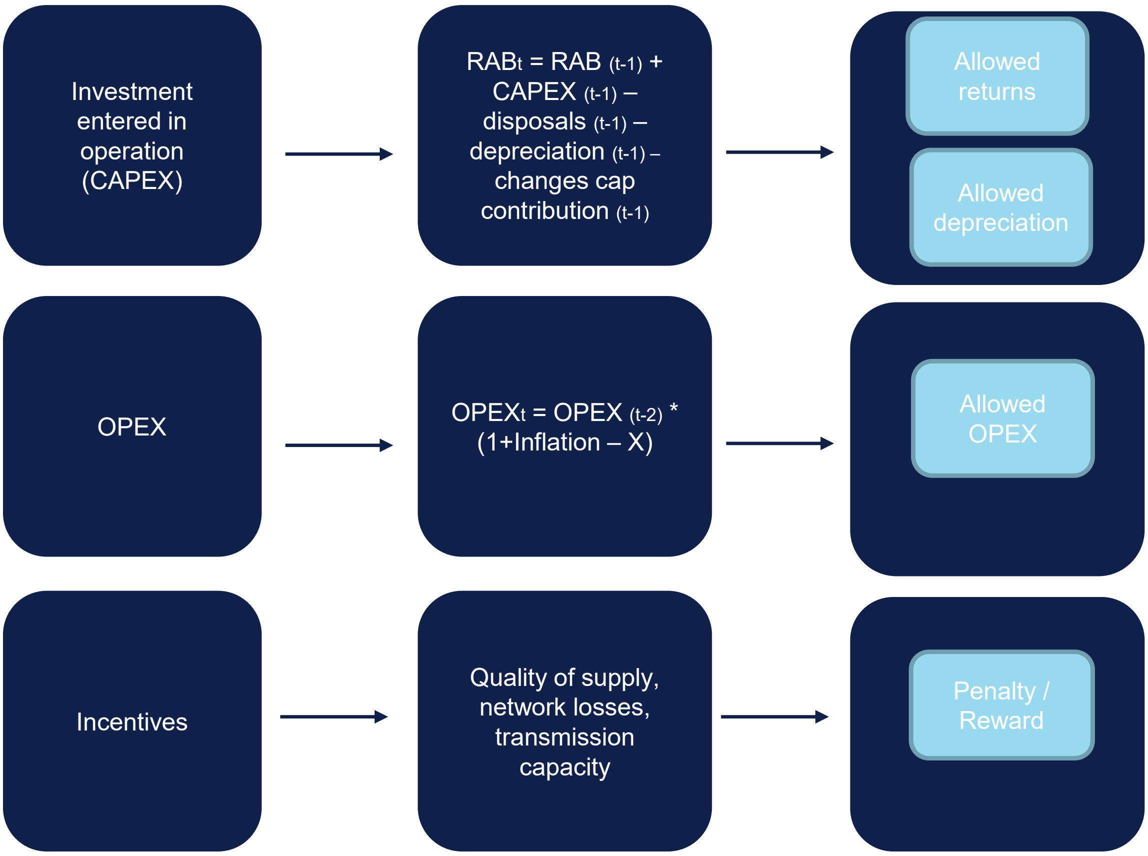

Figure 8: Revenue Setting Overview (Simplified)

7.3.1 Operating Costs

The OPEX are set using an indexation approach. This means that the NRA does not rely on explicit cost projections for the years of the regulatory period. The allowed annual OPEX is set by a simple indexing by inflation (is based on the previous 12-month average of Consumer Price Index) and productivity improvement (X-factor) whereas the starting OPEX is based on the company's actual cost in the base year (t-2). This means for 2016 (the first year of the regulatory period), actual costs of 2014 were applied and for NPR2 the base year is 2018. The actual costs used to set the starting OPEX are netted of financial costs, advertising/ marketing costs, sanctions, tax funds, litigation costs (if unsuccessful) and insurance costs (that do not result from a legal obligation).

In the previous regulatory periods, the X-factor was used as a pure productivity improvement factor. Our understanding is that it is designed as a uniform generic factor that reflects the sector productivity improvement.

Since the third regulatory period, the X-factor not only considers cost-reduction targets, but also incorporates the profit-sharing mechanism.

According to this sharing mechanism the OPEX efficiency gains achieved in the base year (t-2) are shared between network operators and network users in the following regulatory period.

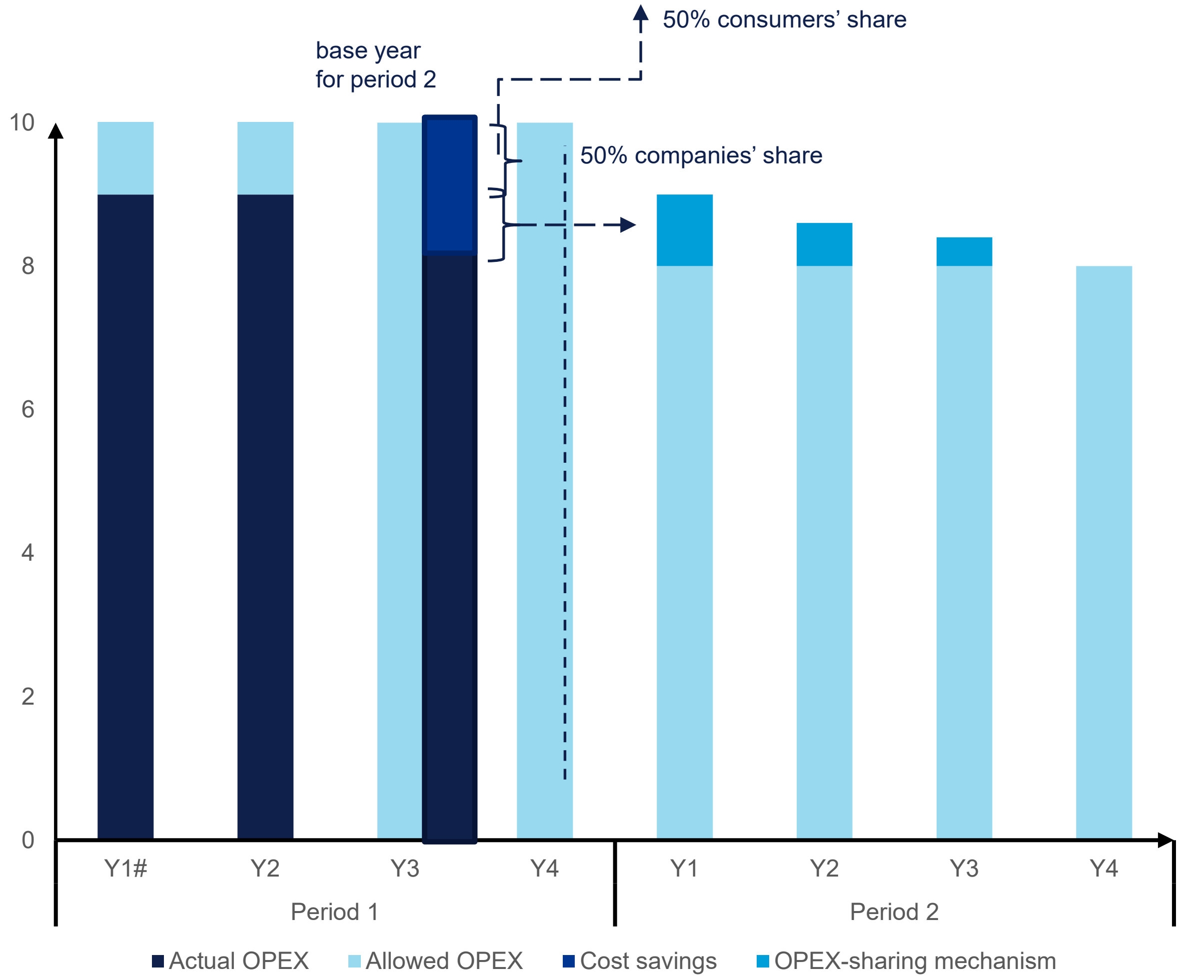

Figure 9: Simplified Representation of the OPEX Sharing Scheme

Source: NRA's Revenue Setting

In case of outperformance (i.e., the actual OPEX is lower than the allowed OPEX), the OPEX efficiency gain is retained by the company. The OPEX efficiency gain in the base year is shared in the next regulatory period (efficiency carry-over).

Specifically, 50% of the OPEX efficiency gain is passed on to the network users through a downward adjustment of the allowed revenues in the first year of the next regulatory period (see the figure above). The remaining 50% of the OPEX efficiency gain are passed on to the network users gradually through the X-factor in the remaining time of the regulatory period. The X-factor is calculated to pass 50% of the efficiency gains to network users, within the regulatory subperiod.

7.3.2 Capital Cost

The capital costs include depreciation and return on assets. The return on assets is calculated as a product of the allowed rate of return and the value of the regulated assets (regulatory asset base, RAB). Investments that are included in the RAB are recouped through the allowed depreciation and earn a return on the undepreciated portion of the investments.

7.3.2.1 Regulatory Depreciation

The regulatory depreciation allowance is calculated on an annual basis per asset groups for assets in the RAB. It applies a straight-line method. The depreciation period is set by the NRA and reflects technical asset lifetimes.

In the last regulatory period, the NRA decided to extend the depreciation periods of selected asset groups. For example, the depreciation period for middle/low voltage lines constructed after 2007 was extended from 30 to 35 years, and for high voltage lines from 40 to 45 years. The reason for the extension was to remove the incentives for network operators to replace assets that are still functional and can continue operating.

7.3.2.2 Regulated Asset Base (RAB)

The RAB is set equal to the net values of the assets for the provision of the regulated network services. The RAB for the first year of the regulatory period is based on the RAB one year before the start of the regulatory period (t-1). The starting RAB is then rolled over in the regulatory period and updated on an annual basis by adding the investments and deducting asset disposals, depreciation, and changes of capital contributions (for example public grants or payments for connection charges).

Investment decisions on electricity networks are taken by network operators. The NRA reviews only ex-post by checking the actual deployment of the investments and the correspondence between investments and reported costs. Investments are added to the RAB with a one-year time lag.

As the allowed rate of return is defined in real terms (see section 7.3.2.3), the RAB is annually adjusted for inflation (gross investment deflator index).

For electricity distribution, both assets that are in operation and assets under construction are included in the RAB. For electricity transmission, assets under construction do not lead to an increase in allowed depreciation until the investment is in full operation, but there is a return on the work in progress. In addition, conditions are applied to the allowed rate of return for these assets which can be lower than the allowed WACC. For example, in the second regulatory period the NRA applies specific rules for fixed assets in construction carried out from the beginning of 2016 and not in operation before the beginning of the respective year in which the allowed revenue is set. According to these rules, the asset in construction will earn a return for a maximum period of four years. For the first two years, the allowed rate of return is set equal to the actual WACC but assuming a debt-to-equity ratio equal to 4. For the second two years, the allowed rate of return is set equal to the cost of debt used in the calculation of the actual WACC. The lower remuneration for assets under construction aims to provide incentives for a timely delivery of the planned investments.

7.3.2.3 Weighted Average Cost of Capital (WACC)

The NRA applies a pre-tax WACC. The pre-tax WACC incorporates the corporate tax in the WACC calculation. Technically, the equity return is increased so that the tax payments can be met from the pre-tax WACC. The capital asset pricing methodology (CAPM) is applied to calculate the WACC components. The WACC is defined in real terms, i.e., excluding inflation. Accordingly, the RAB is adjusted for inflation to maintain consistency in the revenue setting process.

The WACC is set for a regulatory WACC period of six years (2022-2027) for both the electricity and gas networks. It is divided into two subperiods of three years each (2022-2024 and 2025-2027). The current regulatory WACC period does not coincide with the regulatory price control period.

At the end of each regulatory WACC subperiod, the NRA can update the parameters in the WACC. The NRA can also initiate intra-period updates by using the so called “trigger mechanism”. According to the trigger mechanism, such updates are allowed when the cumulated impact on the existing WACC level resulting from changes in relevant parameters exceeds a pre-determined threshold (currently 50 bps/ 0.5 %).

7.3.3 Output-Based Incentives

In addition to the above items, a share of the allowed revenues of electricity transmission and distribution activities result from regulatory incentives linked to the achievement of specific objectives, such as improvements in the quality of supply (see section 7.4).

7.4 Efficiency Incentives / Efficiency Analyses

7.4.1 OPEX Efficiency Incentives

The NRA applies a generic productivity factor (X-factor) to the OPEX. For the subperiod NPR2 (2020-2023) the X-factor is 1.3% (it was 1.9% in the subperiod NPR1) for electricity distribution and 0.4% (1% in NPR1) for electricity transmission.

In the previous regulatory periods, the X-factor was used as a pure productivity improvement factor (see section 7.3.1).

7.4.2 Regulatory Incentives for Reduction of Network Losses

The NRA applies an incentive mechanism for network losses in the electricity distribution network. The distribution network operators are allowed to recover only the cost for standard losses. They are rewarded if their actual network losses are lower than the standard losses set by the NRA. Conversely, the network operators are penalised if their actual network losses are higher than the standard losses set by the NRA.

The standard losses are pre-set target levels (in %) defined by the NRA based on periodic studies conducted by a technical university. There are different percentages for technical losses and commercial losses (which are further differentiated by country regions: North, Centre and South) on the basis of different operating conditions of the network.

7.4.3 Quality of Supply Incentives

Reward/penalty scheme applied to electricity transmission

Transmission quality is regulated with rewards and penalties based on the indicator Energy Not Supplied (ENS). The NRA calculates an initial ENS level for 2016 as the average of the actual ENS for the period 2012-2015. The target ENS for 2016 is equal to the initial level for 2016 adjusted downwards by 3.5%. The target ENS for each year of the period 2017-2023 is set by adjusting downwards the target ENS of the previous year by 3.5%.

The TSO is rewarded/penalised if the actual value of the indicator is better/worse than the target value. The reward/penalty in a given year is the difference between the actual and the target value of that year multiplied by a parameter (expressed in €/MWh) set by the NRA. The reward/penalty is applied only when the difference between the actual and target level exceeds ±5% (dead band). There is also a maximum level of reward and penalty.

Reward/penalty scheme applied to electricity distribution

The NRA applies a reward/penalty mechanism for two quality (reliability) indicators: duration of unplanned long interruptions (SAIDI, System Average Interruption Duration Index) and total number of unplanned long and short interruptions (SAIFI, System Average Interruption Frequency Index and MAIFI, Momentary Average Interruption Frequency Index). For each of these indicators, the NRA sets target levels differentiated by urban ("high customer density" i.e. over 50.000 inhabitants), sub-urban ("medium customer density" i.e. between 5.000 and 50.000 inhabitants) and rural ("low customer density" i.e. less than 5.000 inhabitants) areas. Based on the target level and the starting level (i.e., the trend value of the previous year) of a quality indicator, a quality improvement path is established for the duration of the regulatory period.[46] The quality improvement path marks the expected quality for each year of the regulatory period.

If the companies perform above the requirements, they are rewarded. Conversely, if the performance is below the requirements, they must pay a penalty. The amount of the reward/penalty is the difference between the expected and actual value multiplied by a parameter (expressed in €/kW/minute and €/interruption/kW for the duration and the number of interruptions, respectively) set by the NRA. There is also a dead band and a cap that applies to the rewards and penalties for each year of the regulatory period.

"Special regulation" for geographic areas with number of interruptions particularly worse than the target levels

The NRA applies special rules for geographical areas with quality of supply significantly below the target levels. The regulation is based on the voluntary participation of the network operators. It defines "hypercritical" and "critical" geographic areas,[47] and allows more time to converge to the target level. The distribution network operator should submit a technical report that justifies the reasons to extend the time period to reach the target level. In case the request is accepted by the NRA, the quality improvement requirements are adjusted.

This regulation establishes the payment of a premium at the end of the period, if the target level set by the NRA is reached and a penalty (equal to 1/3 of the premium) if it is not reached.

"Regulatory experiments" applied to electricity distribution

During NPR2, the NRA has been using 'regulatory experiment' rules. According to these rules, a distribution network operator may propose an alternative path to the standard trajectory for improving quality (number and duration of interruptions) in the parts of its network that had previously the worst reliability. The NRA establishes criteria for participation in the "regulatory experiments" and assesses distribution network operators' requests for exemption from the "ordinary" regulation to participate in the experiment. The distribution network operators can propose an improvement path different from that defined by the "ordinary" regulation (i.e., reward /penalty scheme described above), presenting innovative solutions from a technological point of view for quality improvement. In case the request is accepted by the NRA, the quality improvement requirements are adjusted.

The geographic areas of network operators participating in the "regulatory experiments" cannot participate in the "special regulation" described above.

Incentive mechanism to increase the resilience of distribution networks

The NRA has been using quality incentive schemes since 2000. Nevertheless, in the last years the number and duration of supply interruptions increased, in particular due to severe weather events. Weather conditions are considered outside the control of network operators and are excluded from the calculation of the quality indicators. Consequently, distribution network operators were not incentivised to improve the quality to customers disconnected in cases of extreme weather.

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46 The trends are estimated as the maximum value between the target level, and the difference between the starting level and an arithmetic average of the starting and the target level. The trend value for 2020 equals the trend value for 2019 as defined by the NRA (in Resolution 702/2016/R/eel).

47 "Hypercritical" area is defined as a geographic area with an actual number of interruptions 2.5 higher than the target level. "Critical" area is defined as a geographic area with an actual number of interruptions between 1.5 and 2.5 the target level.

The NRA has introduced the obligation to distribution network operators to prepare and publish annually - as part of their Network Development Plans – a resilience plan. The resilience plan is a rolling three-year plan of investments planned by the operator (including justifications) to increase its network's resilience to severe weather conditions. Currently, the obligations to develop the resilience plans refer to specific critical risk factors such as floods, ice and heat waves.

7.4.4 Other

Output-based incentive for cross-zonal transfer capacity increases

For the period 2019-2023, the TSO receives incentive payments for construction of additional transmission capacity in sections between network zones within the national transmission network or on the borders between the Italian and neighbouring transmission networks. This incentive is a reward-only and is determined according to the target transmission capacity set by the NRA. The size of the payments relates to the congestion revenues in previous years and the estimated project benefits. For each section/ border the maximum reward is: 40% of congestion revenues in such section/ border for 2016; 40% of congestion revenues in such section/ border for 2017 and 20% on estimated project benefits as defined in the transmission network planning.

The incentives are capped for each section and border. If the additional capacity suffices to reach the target capacity, the incentive payment is equal to the cap. If it is not, the payment is a share of the maximum incentive value (cap), where the share is the proportion of the additional transmission capacity and the difference between the target transmission and the initial transmission capacity.

Complementary incentive for efficient transmission investment costs

During NPR2, the TSO receives complementary incentive payments in case transmission capacity investment costs for sections between network zones are lower than pre-determined reference cost levels set by the NRA. This is a reward-only incentive and is an add-on to the capacity increase reward (as explained above). The reward is equal to the difference between the reference and actual CAPEX.

7.5 CAPEX Plans

There are no investment plans (yet) for the purpose of setting allowed revenues, but there are network development plans for identifying development projects. A distinction should be made between electricity distribution and electricity transmission.

The TSO is responsible for planning and developing the electricity transmission network. Terna's plan is subject to an opinion by the NRA and approval by the Ministry. The plan is currently submitted on a biennial basis, by the 31st of January of every relevant year (e.g., 2021, 2023, etc).

The NRA has minimum requirements for the sufficiency and transparency of these plans. This includes the need to justify proposed investments using cost benefit analysis for large projects (above 15 million €). The NRA organises a consultation with stakeholders on the outline of the plans.

Distribution network operators are also required to publish annually development plans for their networks primarily for information purposes; the NRA does not explicitly provide an opinion on those plans. The distribution network plans are prepared in coordination with the TSO and are consistent with the national transmission network plan.

As a practice (except a few circumstances in the past), an approved project of the transmission plan is entitled for CAPEX recovery. Investments are added to the RAB with a one-year time lag. Except for large-scale transmission projects, no ex-ante CAPEX reviews are applied.

7.6 Innovation Incentives

As explained in section 7.4.3, the NRA applies a series of incentive schemes that implicitly favour the dissemination of innovative technologies.

The NRA also applies explicit investment incentives by allowing a temporarily higher rate of return for certain types of investment (including innovative solutions and technologies). This is explained below.

Electricity distribution

Certain types of investments (e.g., new HV/MV substation) commissioned in the years 2008-2011 are allowed to earn a mark-up on the rate of return on invested capital (WACC premium). The WACC premium is 2% and these premiums are added to the regular WACC during 8 to 12 years. For example:

- Investments in new HV/MV substation: 2% for 8 years
- Investments in replacement of existing transformers in MV/LV substations with low-losses transformers: 2% for 8 years
- Investments in MV network automation, protection and control systems (smart grids): 2% for 12 years

There are also WACC premiums for certain types of investments (e.g., pilot projects on smart grids and storage systems) commissioned in the years 2012-2015. These incentives were abandoned in 2015 as the NRA decided to move from input-based regulation to more output-based regulation. The WACC premiums are between 1.5% and 2% and these premiums are added to the regular WACC during 8 to 12 years. See the examples below.

- Investments in replacement of existing transformers in MV/LV substations with low-losses transformers and installation of new low-loss transformers in existing or newly built MV/LV substations: 1.5% for 8 years
- Investments in pilot projects on smart grid selected by the NRA: 2% for 12 years
- Investments in network renewal and reinforcement in MV networks in historical centres: 1.5% for 12 years
- Investments to enhance the capacity of primary substations in specified critical network areas: 1.5% for 12 years
- Investments in pilot projects on storage systems selected by the NRA: 2% for 12 years

Electricity transmission

Incentives using a WACC premium were also applied for certain types of investments in the transmission network commissioned in the years 2012-2015. The WACC premiums are between 1.5% and 2% and these premiums are added to the regular WACC for 12 years. For example:

- Investments in the development of transmission capacity related to strategic projects necessary to reduce congestions between market areas, or to increase the Net Transfer Capacity (NTC): 2% for 12 years
- Investments in pilot projects related to storage systems selected by the NRA: 2% for 12 years
- Investments in the development of transmission capacity including investments with relevance for the country defence plan: 1.5% for 12 years

7.7 Role of Forward-Looking Estimations

The NRA applies forward-looking elements in the estimation of the allowed rate of return (WACC).

In particular, the NRA adjusts the risk-free rate of return by a forward premium (estimating expected future interest rates of bonds with different maturities) and an uncertainty premium (to account for potential differences between the future spot and forward rates).

The NRA also incorporates forward-looking elements in the estimated cost of debt. The cost of debt is based on market benchmarks (i.e., iBoxx indices representing the yield of bonds issued by BBB-rated companies) and is set by weighting the cost of existing and new debt.[48] The forward and uncertainty premiums are also applied for the cost of new debt.

7.8 Regulation and Energy Transition

7.8.1 Implication of Energy Transition on Networks

The Italian Long-Term Strategy on Reducing Greenhouse Gas Emissions (January 2021) clearly articulates the implications of the energy transition for the electricity networks. It is expected that the electricity consumption will double, and that the RES installed capacity will substantially increase by 2050. Thus, large investments will be required in the electricity networks to accommodate the changes in the demand and supply conditions.

In March 2022, the TSO announced that it expects to invest about €10bn in Italy's energy transition, energy independence and decarbonisation efforts over the period 2021-2025 (Terna, 2022). The TSO's strategy is strongly focused on infrastructure development, integration of RES, storage systems and cross-border interconnections.

The DSO (Enel) has similar forecasts. According to the Enel Strategic Plan 2023-2025, the company plans network investments of about €12.5bn in the next 3 years (Enel, 2020). The major investments relate to connection of generation plants and new load sources to the distribution network, improvement of quality of supply and increases in the resilience of the distribution network. There is also an important component of network investments focusing on digitisation and technological innovation.

7.8.2 Impact on Regulation

The role of the energy transition is recognised by the NRA in the strategy paper on 2022-2025 Strategic Framework (ARERA, 2021a). In this paper the NRA clearly states the importance of environmental sustainability and the need for cross-sector coordination in network development.

As explained in the previous sections, the NRA has been using several output-based incentive mechanisms (quality of supply, investments in targeted segments, network resilience) in the regulation of electricity transmission and distribution. In addition, the NRA intends to gradually implement a new method to set allowed revenues (Regulation by Expenditure and Service Objectives, ROSS). The new regulation will apply a TOTEX approach based on the analysis of forward-looking business plans prepared by the network operators.

48 The cost of debt is based on market benchmarks (i.e., iBoxx indices representing the yield of bonds issued by BBB-rated companies), including a weighting between the cost of existing debt and that of new debt. For the cost of the new debt a forward premium and an uncertainty premium is also applied like the forward-looking approach adopted for the risk-free rate. Moreover, there is a gradual mechanism, whereby the cost of debt is calculated as a weighted average of the cost of debt allowed in the previous regulatory period (2016-2021) and the cost of debt based on the new methodology.

7.8.3 Treatment of Uncertainty

The current regulatory regime allows for an interim review as the regulatory period is divided into two subperiods. The interim review allows the NRA to identify issues that could not have been anticipated at the beginning of the regulatory period and initiate changes that will apply in the next subperiod.

As mentioned, a similar approach is applied for the WACC where the regulatory framework envisages two WACC sub-periods and the potential use of a trigger mechanism (see section 7.3.2.3).

8 BELGIUM

8.1 Background Information

The Belgian Federal Commission for Electricity and Gas Regulation (CREG) carries out the economic regulation of the national transmission system operator (TSO), Elia.

Economic regulation of distribution network operators (DSOs) is in the hands of regional regulators:

- the Flemish Regulator of the Electricity and Gas market (VREG) for Flanders, covering multiple municipal distribution network operators united under Fluvius;
- the Walloon Energy Commission (CWaPE) for Wallonia, covering multiple municipal distribution network operators; and
- Brussels Gas Electricity (BRUGEL), covering Sibelga as the operator of the electricity distribution grid for the Brussels-Capital region.

In the following sections, we have drawn on the current approaches set out by CREG (transmission) and VREG, respectively, with a focus on VREG's methodology for electricity distribution. In addition, we provide an overview of the key performance indicators (KPIs) applied to electricity distribution in the Brussels-Capital region.

8.2 Price Control Model

Electricity network operators are regulated using revenue caps with a regulatory period of 4 years. The current regulatory period is 2021-2024 for distribution. For transmission the regulatory period is 2020-2023.

VREG's methodology focuses on the recovery of distribution network operators' reasonable and efficient costs, which are split into endogenous and exogenous costs (VREG, 2022, section 5). The endogenous costs are "the reasonable and necessary costs for network operation" which the network operator can control and are subject to efficiency incentives. In the current regulatory period VREG applies incentives for cost efficiency and quality of supply (see section 8.4). Furthermore, VREG can apply specific additional incentives. The Energiedecreet (Energy Decree in English) (Art. 4.1.32 §1, 15°) mentions the possibility of incentives for market integration, security of supply and research and development. Although such specific incentives were not yet applied, they can be introduced during the regulatory period.

The exogenous costs are the costs that the network operator cannot reasonably control, including costs related to green power/cogeneration certificates and consumer energy efficiency premiums. These costs can be passed through to distribution tariffs.

At the transmission level, the basis for CREG's tariff methodology for the TSO is to cover the "necessary and efficient" costs to deliver the regulated transmission service.[49] CREG's methodology makes the distinction between non-controllable (pass through), influenceable (partially controllable) and controllable costs. CREG has also introduced incentives to improve the cost efficiency and quality of supply (see section 8.4).

[49] Elia is responsible for network management, system operation, balancing / imbalance management and market integration services.

8.3 Revenue Setting/Cost Assessment Principles

8.3.1 Distribution

VREG sets allowed revenues for the regulatory period as the total of a budget for planned exogenous costs and a budget for allowed endogenous costs including annual adjustments for inflation (CPI) and efficiency incentives (see section 8.4).

VREG determines the allowed revenues for exogenous costs ex-ante, based on the budget submitted by the respective DSO including a justification for its budget.

VREG distinguishes three types of endogenous costs: operating costs, depreciation and return on assets.

For endogenous costs, VREG sets a baseline revenue allowance for every year of the regulatory period. This baseline revenue allowance aggregates the allowed operating and capital cost and is subject to annual inflation adjustment as well as adjustment through the efficiency incentives. In addition, VREG applies several further adjustments to the baseline revenue allowance (see section 8.3.1.3) (VREG, 2022, section 5.5).

8.3.1.1 Operating Costs

Operating costs incurred for the purpose of delivering regulated network services are considered endogenous costs. To determine the allowed OPEX, VREG uses the actual OPEX of the last historical financial year as a reference for each individual year throughout the period.

8.3.1.2 Capital Costs

The capital costs include depreciation and return on assets. The capital costs include a “normative remuneration” set by VREG to reflect the existing assets and efficient network investments. The remuneration is normative as it is calculated and applied in an equal, non-discriminatory way for all DSOs. It is the remuneration for a DSO who knows how to finance itself in an efficient manner. The return on assets is the product of the RAB and the rate of return.

Depreciation

Assets are depreciated using straight line depreciation method and regulatory accounting lifespan.

Regulatory Asset Base

Network operators are required to submit the RAB value in nominal terms on the basis of the remaining value after depreciation (where applicable). Tangible fixed assets include typical asset categories for network businesses (e.g., land and buildings, installations, machinery and equipment, furniture and vehicles, fixed assets under lease, other tangible fixed assets, fixed assets under construction).

The RAB is rolled over by adding the new investments in the tangible fixed assets and deducting depreciation allowances. The RAB is further adjusted for divestments, revaluation, changes in third party contributions/capital grants (subsidies) and changes in working capital.

Rate of Return

The rate of return for the current regulatory period is 3.5% nominal pre-tax WACC. The use of historical purchase costs as the basis for the RAB is consistent with a nominal WACC (which includes inflation) (VREG, 2021b).

8.3.1.3 Revenue Adjustments

VREG uses “regulatory balances” to account for changes in specific cost components. A regulatory balance is a surplus (positive value) or shortfall (negative value) for the network operator, caused by differences between expected (ex-ante) and actual (ex-post) costs or inflation. VREG uses regulatory balances for the following:

- Exogenous costs;
- Volume-related endogenous costs;[50]
- Inflation;
- Corporate Tax; and
- Revaluation surpluses in RAB. [51]

Half of the regulatory balances of each of the two years preceding a given year are added to the allowed revenues for the given year.

8.3.2 Transmission

CREG requires the TSO to prepare an ex-ante reporting model with information on proposed cost budgets for the next regulatory period, as well as an ex-post historical costs (CREG, 2018a).

The TSO gives CREG a first tariff proposal for the next regulatory period based on the ex-ante model. The tariff proposal must contain the estimated total revenues across all relevant tariffs and sufficient supporting information and calculations to enable CREG to evaluate the proposal. Should CREG decide not to approve the tariff proposal and/or require adjustments, then the TSO has to substantiate this requirement and provide supporting evidence (CREG, 2018b).[52]

Over the course of the regulatory period, the TSO uses the ex-post reporting model to submit updated tariff reports once every two years. If relevant, adjusted tariff reports are submitted should they be requested by CREG.

8.3.2.1 Operating Costs

CREG acknowledges that, because operational expenses are strongly related to capital investments and investments can vary over the course of the regulatory period, it is not appropriate to let OPEX evolve through a simple indexation of the cost level of the first year of the regulatory period.

The TSO is therefore asked to submit justified, annual budgets for operational expenses on which the tariff proposals are based. These budgets must include the necessary and justifiable costs to deliver its regulated activity. In addition, the tariff proposal must contain a clear justification for proposed operational expenses. The annual budget is subject to potential ex-post corrections by CREG.[53]

8.3.2.2 Capital Cost

Capital costs include depreciation and return. The return on assets is the product of the RAB and the rate of return.

50 These are variable cost components that change with the distributed electricity. This covers the difference between expected sales volumes used in the tariff proposals and the actual volumes collected.

51 This covers the difference between the ex-ante budget for capital costs and the actual amount of capital costs (after the end of the financial year).

52 CREG has to provide a rationale if it does not approve costs.

53 This would be in case actual operating costs are significantly different from budgeted costs.

Depreciation

Assets are depreciated using regulatory accounting lifespans (which vary per category of assets) and the straight-line method is applied.

Regulatory Asset Base

The value of the RAB is based on assets' historical purchase costs. The RAB is rolled over by adding the new investments in fixed assets and deducing depreciation allowances. The RAB is further adjusted for divestments, revaluation, changes in third party contributions/capital grants (subsidies) and changes in working capital. CREG assesses the new investments at the time it reviews the (ex-ante) budget proposed by the TSO.

Rate of Return

CREG employs an embedded debt approach within the CAPM framework. The debt financing costs are directly incorporated into the allowed revenues (the financial costs are regarded as non-manageable costs). As a result, CREG calculates a rate of return to reflect the cost of equity, equal to a risk-free rate plus the market risk premium multiplied with the beta factor for the TSO. The cost of equity was set at 4.255%.

8.4 Efficiency Incentives /Efficiency Analysis

8.4.1 Distribution

8.4.1.1 Application of Efficiency and Productivity Analysis

VREG acknowledges that network operators may achieve further efficiency improvements through productivity improvement, catch-up and economies of scale.

Productivity Improvement

The frontier shift reflects the productivity improvements that can be achieved by firms through best practice (highest level of technological advancement achieved by a DSO). VREG believes that the regulated network companies should be able to realize this productivity level. Accordingly, VREG imposes an annual percentage reduction of endogenous costs in the allowed revenues from 2021 to 2024. This percentage is equal to the average sector-wide (electricity and gas distribution) annual percentage reduction in realised endogenous costs over the period 2015-2019.

To explore the potential of productivity gains over and above the sector-wide trend, VREG also commissioned a study on productivity growth (frontier shift) in other competitive sectors of the Belgian economy. The study found that the regulated network operators should be able to achieve a frontier shift productivity improvement of 0.4% per year over the course of the next regulatory period. However, upon further review, VREG set the frontier shift value for electricity distribution to 0.0% on the basis that the sector itself had already realised efficiency gains commensurate with the frontier shift.

Catch up

VREG has expressed its intention to introduce a further "catch-up" efficiency incentive informed by benchmarking of DSOs' endogenous costs. So far VREG has not conducted such a benchmarking study and has not implemented such an incentive.

Economies of Scale

In the 2021-2024 regulatory period VREG has introduced an explicit requirement for productivity improvement to reflect economies of scale and synergies following the 2018 merger of Eandis System Operator cvba and Infrax cvba to form Fluvius System Operator CV (FSO). The incentive came into place through modification of the 2017-2020 tariff methodology and takes the form of a reduction of allowed endogenous costs, to be realised by 2024.

VREG explains (VREG, 2022, section 6.3) the basis for this incentive by pointing to the efficiency gains to be achieved post-merger, e.g., from downsizing the organization's workforce and merging departments or functions, combined with a reduced ability (for VREG) to benchmark businesses, since only FSO remains as a single entity. The incentive aims to ensure the new entity realises the full efficiency gains following the merger. At the time, these efficiency gains were estimated to equal EUR 109 million in total by 2024, of which EUR 73 million for electricity distribution. Of this amount, VREG imposed EUR 26.5 million in efficiency savings for 2019 and 2020, combined. The remaining EUR 56 million of savings is to be delivered in the current regulatory period, of which EUR 14 million in 2021, and EUR 42 million over 2022-2024 (VREG, 2022, section 5.3.3.4.1).

8.4.1.2 Quality of Supply Incentive

VREG adjusts the network operators allowed endogenous costs by a Q-factor based on the quality performance over the 2017-2019 period (VREG, 2020). The quality performance is based on the frequency (SAIFI) and duration (SAIDI) of supply interruptions, and delays in the connection process.

The incentive involves a scoring mechanism, in which VREG awards points to networks operators for:

- DSO performance against the sector average SAIDI and SAIFI at low and mid voltage levels; and
- the average value of penalties paid for delays in customer (re-)connections across the total number of (re-)connections delivered in a given year.

The incentive is bi-directional, meaning that DSOs are rewarded for "good" performance, and penalised for "bad" performance. Additionally, it is a "zero sum game" across the electricity distribution sector, meaning that the net effect of rewards and penalties on allowed income across DSOs is zero.

8.4.2 Transmission

8.4.2.1 Application of Efficiency and Productivity Analysis

The efficiency analysis is embedded in the cost assessment process, i.e., the process through which CREG reviews tariff proposals submitted by the TSO and approves underlying costs (see section 8.3.2). No specific factors for efficiency/productivity improvements are used.

8.4.2.2 Quality of Supply Incentives

CREG has put in place three incentives to encourage the TSO to seek continuous improvement of its quality of supply (CREG, 2018a, section 5.3.3.3). The incentives relate to:

- New connections – for performance in meeting deadlines and budgets to realise new/changed connections, based on an annual customer satisfaction survey (addressed to users whose connection expired during the previous year).

- Customer satisfaction – based on two biannual customer surveys, the first assessing satisfaction among the members of the network operator's user group, and the second assessing the general satisfaction of all network users regarding the commercial relationship with the TSO; and
- Data availability – assessing the data made available to the market by the network operator on its website as well as on the website of ENTSO-E.

All three incentives are positive (reward only) financial incentives equal to a percentage of the RAB value for the relevant year, capped at an amount specified by CREG.

8.5 CAPEX Integration / Investment Incentives

8.5.1 Distribution

VREG has the duty to review and, where appropriate, reject the investment costs of the DSO's.

Endogenous costs that are rejected by VREG on the grounds of being not reasonable or insufficiently justified are not included in the costs that determine the allowed revenues for the upcoming regulatory period.

VREG considers the network operators' capital expenditures reasonable so long as they meet all of the following criteria:

- Costs are necessary for the performance of the regulated tasks of the distribution network operator.
- Cost figures comply with calculation and accounting rules imposed by law, regulation or VREG.
- Costs are in the public interest.
- Costs cannot reasonably be avoided.

The regulatory documents, however, do not provide information on any specific methods that should be used in the CAPEX review process.

8.5.2 Transmission

Each year the TSO is required to propose a cost budget, covering the following:

- Proposed capital investments as per TSO's long-term development plan and approved by relevant regional authorities;
- Any additional proposed capital investments not previously included in the long-term development plan;
- Changes to buildings or TSO's wider asset portfolio; and
- Any one-off and foreseeable maintenance costs of the Modular Offshore Grid.

The TSO is required to classify expenditures in this budget as follows:

- Expenditures related to the maintenance of the existing Belgian network;
- Expenditures related to the development of the existing Belgian network; and
- Other expenses that are not directly related to a specific tangible asset.

CREG assesses whether costs are reasonable and efficient, using the same criteria of necessity, compliance with rules, public interest, and (in)ability to avoid as VREG (CREG, 2018a, section 5.4).

As the principal overarching efficiency (sharing) incentive, CREG awards 50% of the (positive or negative) difference between approved budgeted controllable costs and the actual value of these costs to the TSO in the form of annual ex-post revenue adjustments in the subsequent regulatory period.

CREG can apply ex-post corrections to allowed controllable costs depending on:

- realised capital investments;
- realised non-recurring announced maintenance works of the Modular Offshore Grid; and
- actual inflation.

Such corrections are applied to allowed revenues in the subsequent regulatory period.

CREG also applies an explicit incentive to the costs associated with the procurement of ancillary services. This is based on its ex-post assessment of the "fair value" of ancillary service costs. In particular, CREG awards the TSO 20% of the difference (positive or negative) between approved and "fair" costs in the form of annual ex-post revenue adjustments.

8.6 Innovation Incentives

8.6.1 Distribution

VREG has not yet used financial incentives that promote innovation in network operation.

8.6.2 Transmission

The 2016-2019 regulatory period contained an explicit incentive for the TSO to undertake innovation projects. This incentive combined grants and targeted subsidies for the cost of realising such projects. For the 2020-2023 regulatory period, due to concerns about potential duplication of funding, CREG replaced this incentive with two separate incentives:

- A percentage allowance on the value of capital grants received for qualifying innovation projects over the previous year; and
- A percentage allowance on the expenditures required to deliver approved R&D plans for the upcoming regulatory period. To qualify for this allowance, the TSO must submit a plan for approval to CREG providing a description of the research and development projects envisaged, including the expected results, a schedule and a budget. CREG allows for this plan to be adjusted annually. To ensure the incentive rewards actual delivery, for each year of the regulatory period, the TSO is reimbursed a percentage of the costs incurred for the realization of the R&D plan. The projects targeted under this innovation incentive must directly relate to energy transition, market integration, "public acceptance" or efficient management of the network.

8.7 Regulation and Energy Transition

8.7.1 Implication of Energy Transition on Networks

At the distribution level, VREG has not yet used financial incentives that could seek to support activities to realise the energy transition.

At the transmission level, incentives to realise the energy transition are reflected in innovation incentives (see section 8.6.2), which encompass funding support for projects related to the energy transition. The tariff methodology, however, does not provide any more specific requirements or criteria for these projects.

8.7.2 Integration of European Energy Markets

CREG has put in place a set of incentives for the TSO to encourage market integration and enhancement of security of supply (CREG, 2018a, section 5.3.3.2). They involve:

- the allocation to the TSO of a share in the gains from participations in companies contributing to market integration and/or security of supply;
- a revenue allowance for the increase in interconnection capacity realised in the Belgian network area, determined by a calculation based on:
    - the characteristics of critical network elements included in the market coupling;
    - the result of the market coupling;
    - electricity demand in the Belgian network area;
    - redispatching costs; and
- efforts aimed at the reinforcement of the Belgian transmission network.
- a revenue allowance for the timely completion of major infrastructure projects that contribute to market integration.

8.8 Key Performance Indicators (Brussels-Capital region)

Sibelga is the distribution network operator in the Brussels-Capital region. The current tariff methodologies established by BRUGEL cover the years 2020-24 and are based on a hybrid cost-plus model. The tariff methodology includes an incentive regulation mechanism based on key performance indicators (KPIs). Through these KPIs the DSO is incentivised to reach certain thresholds set by BRUGEL for a selection of parameters. The KPIs cover the quality of (Brugel, 2020, section 3.1):

- *The distribution service*, reflecting the continuity of the distribution service to end-users measured by SAIDI and SAIFI targets;
- *The metering service*, reflecting the completeness, responsiveness, and quality of metering services as follows:
    - *completeness* measures the ratio of meters read to the total population of meters (this is measured for each type of meter: conventional, monthly automated reading, continuous automated reading and smart meters), and the ratio of unread meters (for more than two years) to the total number of meters read (this is measured for conventional meters).

- o *responsiveness* measures (1) the average time taken to relay meter data to the market from the time the meter was read, (2) the ratio of timely (i.e., within a term set by BRUGEL) meter data relays to the total population of meters, and (3) the average time taken to relay corrected meter data to the market from the time a correction request was received.
- o *quality* measures the ratio of accepted meter correction requests to the number of meter reads submitted to the supply company.

- *Services provided to the market*, reflecting the responsiveness in carrying out services/works requested by stakeholders (either supply companies or connected customers), which is measured as the ratio of timely (i.e. within a term set by BRUGEL) executed service requests to the total number of requests received.[54]
- *Complaints management*, reflecting the responsiveness in responding to complaints and request for compensation, which is measured by (1) the ratio of timely (i.e., within a term set by BRUGEL) resolved complaints to the total number of complaints received, and (2) the ratio of timely (i.e., within a term set by BRUGEL) processed compensation requests to the total number of requests received.

All of these KPIs individually are bi-directional (i.e., can involve a reward or a penalty).

BRUGEL applies a scoring mechanism in which each of the above 4 KPIs is weighted. Drawing on historic data and in collaboration with Sibelga, determines the performance thresholds and trajectories for each individual KPI (and sub-KPIs) to apply from 1 January of the next year in the regulatory period. The performance against each individual KPI, and the rewards or penalties realised from this performance, form an "incentive envelope" (bandwidth), reflecting the target performance spectrum across all KPIs for Sibelga (see illustration below).

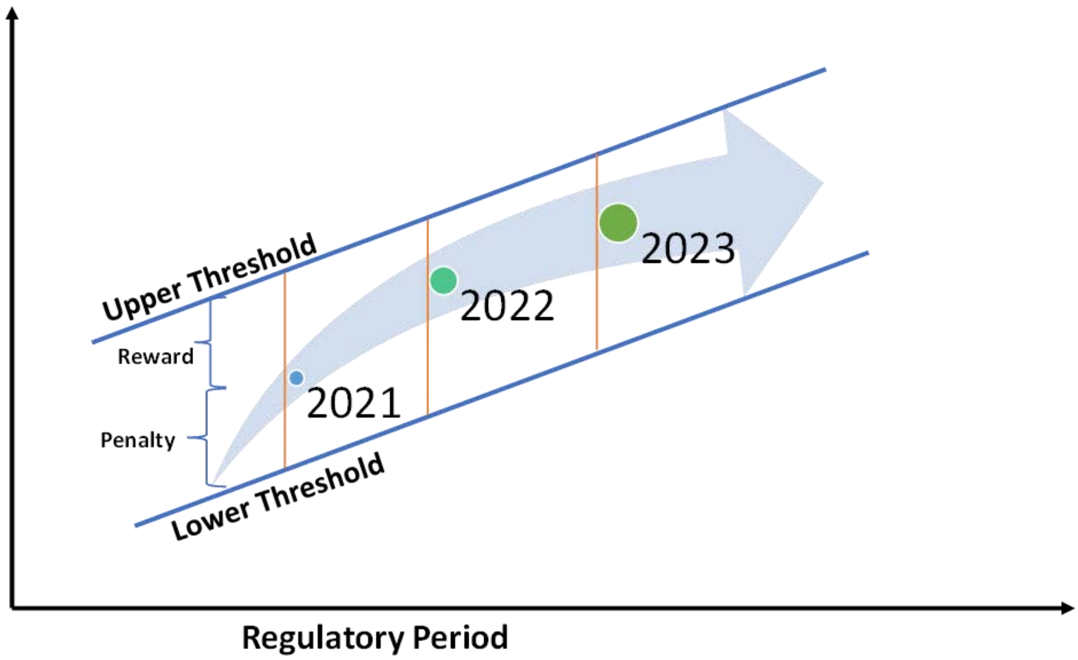

Figure 10: "Incentive envelope" (bandwidth)

For the 2020-24 regulatory period, the value of the incentive is set to 2.75% of the annual reasonable return on assets (WACC x RAB). This incentive is asymmetric on aggregate (across all individual KPIs), meaning that with good performance against KPIs Sibelga can earn a maximum of 2.75%, but with poor performance (i.e., if the sum of penalties against KPIs is greater than the sum of rewards), the incentive equals 0%.

54 Services/works are e.g., the placement of limiters, the processing of "move ins" and "move outs", disconnections, etc.

9 FINLAND

9.1 Background Information

The power system in Finland is part of the inter-Nordic system together with Sweden, Norway, and Eastern Denmark. The inter-Nordic system is connected to the power system in Continental Europe by means of direct current transmission links. Moreover, there are direct transmission links to Finland from Russia and Estonia.

Fingrid Oyj is responsible for the provision of transmission services including planning, construction, operation, maintenance, balancing and control of the transmission system. The transmission network encompasses approximately 5,500 km of 400 kV transmission lines, 1,400 km of 220 kV transmission lines and 120 substations.

At the end of 2021, there were 77 electricity distribution system operators having networks with voltage levels below 110 kV. In addition, there were 9 high-voltage distribution system operators having only high-voltage networks of 110 kV or above. The biggest distribution network operators in Finland are Caruna, Elenia and Helen Electricity Network Ltd.

The Energiavirasto is the Finnish regulatory authority for the economic regulation of the electricity and natural gas networks.

9.2 Price Control Model

The electricity transmission and distribution activities are regulated based on a revenue cap methodology. The length of the regulatory periods is four years (both for transmission and distribution), though the methodology is set for two consecutive regulatory periods (e.g., 2016-2019 and 2020-2023).[55] The current, and fifth regulatory period is from 2020 to 2023.

The Finnish price regulation includes several incentive schemes related to investments (section 9.5), quality of supply (section 9.4.3), efficiency (see section 9.4.2), and innovations (see section 9.6).

9.3 Revenue Setting /Cost Assessment Principles

The yearly allowed revenues for electricity transmission and distribution are based on the information submitted by the network operators that is reviewed by the NRA Allowed revenues include the allowed operating costs and capital cost (depreciation and return on assets).

Furthermore, allowed revenue are adjusted using an integral adjustment scheme (see section 9.3.3).

9.3.1 Operating Costs

Operating costs are divided into controllable and non-controllable OPEX. Controllable OPEX are subject to efficiency improvement incentives. The controllable OPEX include for example costs of materials, personnel expenses, and costs of leasing. Operating costs that are outside of the control of network operators are considered non-controllable.

[55] Since the Energiavirasto has already confirmed in advance these two regulatory periods, the changes require one or more of the reasons provided in the Finnish Act on Supervision of Electricity and Natural Gas Markets. Clause 13 refers that changes to the confirmation decision are possible only if the decision is made based on erroneous information, or legislation is changed, or international obligation requires this.

To determine the allowed OPEX, the NRA uses an OPEX starting level based on historical data. The allowed OPEX (reference or reasonable cost) for each year of the regulatory period are calculated by indexing the starting level. This indexing depends on efficiency targets, inflation and network volume drivers (see section 9.4.2).

9.3.2 Capital Costs

The capital costs include depreciation and return on assets. The return on assets is the product of the regulatory asset base (RAB) and the rate of return.

According to the Finnish Electricity Market Act, network operators must submit network development plans to the NRA bi-annually. The NRA reviews the investment costs by using its own estimations based mainly on the application of standard unit price analysis.

9.3.2.1 Depreciation

The NRA applies a standard depreciation allowance based on asset replacement cost, the straight-line method and asset specific lifetimes. An asset specific lifetime is an estimate of the average amount of time that an asset is in actual use before being replaced. The NRA has set ranges for these lifetimes and the network operators can choose the lifetimes of their assets within the relevant ranges.

9.3.2.2 Return on Assets

The NRA determines a reasonable return for each network operator on an annual basis. This return is calculated by multiplying the adjusted capital invested in network operations by a reasonable/allowed rate of return (WACC).

Capital Invested in Network Operations (Regulatory Asset Base)

The network operators earn a reasonable return on the adjusted capital invested in network operations. The adjusted capital invested in network operations is determined as follows.[56] First the gross replacement value of the network assets is determined using asset specific unit prices set by the NRA (Energiavirasto, 2015a, 2015b, Appendix 1).[57] The net replacement value is then calculated from the gross replacement value by subtracting the relevant depreciations. The net replacement value is adjusted upwards by the current assets. In a final step the non-interest-bearing-debt is deducted. Non-interest-bearing debt include items such as accounts payable, accruals and other short-term debt.

Weighted Average Cost of Capital (WACC)

The allowed rate of return is equal to the WACC (Weighted Average Cost of Capital), which is determined according to the CAPM (Capital Asset Pricing Model). According to this model the cost of equity depends on the risk-free interest rate, a beta coefficient, the market risk premium and the illiquidity premium.[58] Similarly, the cost of debt is the sum of the risk-free interest rate and a risk premium. The NRA uses a fixed 40/60 debt-to-equity ratio to calculate the WACC and, consequently, the reasonable rate of return.

Most of the WACC parameters are fixed for the methodology period (two regulatory periods) except the risk-free rate, which is updated annually and the risk premium of debt, which is updated for each regulatory period.

The methodology for calculating the risk-free rate was amended in 2021 in such a way that it takes a shorter-term view of the risk-free rate rather than averaging over a 10-year period as was done previously. The risk-free rate for the years 2022

56 The value of the network assets included in the balance sheet of the network operators is not used to calculate the reasonable return. Instead, the asset replacement value is used. Therefore, the regulation refers to the adjusted capital invested in network operations.

57 Prior to 2016, the unit prices for all components that formed the regulated asset base were updated for each regulatory period. From 2016, the updates were planned to be made every two regulatory periods, however, the prices were most recently updated in 2021, and came into effect in 2022.

58 The premium for lack of liquidity describes any illiquidity of an investment due to for example higher transaction costs and a longer sale period than the ownership of a listed company.

and 2023 is determined using the arithmetic average of daily returns of the ten-year Finnish government bonds during the period of April-September of the previous year. The risk-free rate was previously determined by averaging daily returns over 10-year periods.

9.3.3 End-of-Period Regulatory Review

At end of the regulatory period, the NRA reviews the financial results of the network operators. For this purpose, the NRA compares the adjusted actual operating profit with the allowed return of the individual network operators for every year of the regulatory period.[59] The comparison aims to detect whether the network operators have incurred gains (losses) other than those envisaged in the regulatory incentive schemes. Such gains (losses) are not eligible to be retained by the regulated companies and should be returned to the network users.

For the purpose of the comparison, The NRA adjusts the actual operating profit (i.e., the earnings before interest and tax, EBIT) of the individual network operators by the financial impact of the incentives. Specifically, The NRA adds to the actual operating profit the actual costs and deducts the allowed costs related to the respective incentive. In this way the actual operating profit is adjusted to represent the financial result that the network operator would have achieved if it has incurred exactly the allowed costs.

The adjusted actual profit is compared with the allowed regulatory return. The calculated annual difference for each year of the regulatory period is cumulated over the entire period. The aggregated surplus (the aggregated actual profit that exceeds the reasonable regulatory return on assets) is given back to the network users by adjusting downwards the allowed revenue in the subsequent regulatory period. The aggregated shortfall (the aggregated actual profit that falls behind the reasonable regulatory return on assets) is charged to the network users by increasing the allowed revenue in the subsequent regulatory period.

The approach mentioned above can be illustrated by the following simplified example using a single efficiency incentive on the controllable OPEX.

- The example assumes that the allowed OPEX is 70 € and the actual OPEX is 60 €.
- The network company has achieved an actual operating profit π equal to 40 €.
- The actual operating profit incorporates by definition the realised efficiency gain of 10 € reflecting the difference between the allowed and actual OPEX.

When compared to the allowed regulatory return, the actual operating profit is however adjusted.

The adjustment adds to the actual operating profit the actual OPEX and deducts the allowed OPEX, $\pi^* = \pi + 60$ € - 70 € = 40€ - 10 € = 30 €). It removes the efficiency gain of 10 € for the purposes of comparison. The result is that the network operator will be able to retain the efficiency gain.

This adjustment is applied to the actual operating profit for each of incentive schemes respectively – these are investments, quality of supply, efficiency, innovations, and security of supply.

9.4 Efficiency Analysis / Efficiency Incentives

The electricity transmission and distribution companies are subject to efficiency incentives. There are targets for general productivity and individual (company-specific) efficiency improvements.

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59 Conceptually the comparison is justified by the fact that the operating profit expresses the restated EBIT (the sum of the net profit, interest and taxes) and the regulatory return on assets is calculated by using a rate of return /WACC) that integrates equity and debt returns and is established on a pre-tax basis.

9.4.1 General Productivity Improvement Target

The NRA commissioned a study to assess the level of general efficiency by examining the productivity development in various network activities. The outcome of the study recommended a general efficiency target of 2%. However, the NRA decided to set the general productivity target for the fourth and fifth regulatory period equal to 0%.

With this decision The NRA took into consideration the expected future cost burden caused by new tasks of the network operators resulting from amendments in the legal framework. Examples of these new tasks are the mandatory requirements for hourly metering and remote reading for energy metering.

9.4.2 Individual Efficiency Targets

The objective of the individual (company-specific) efficiency target is to encourage the less efficient network operators to improve their efficiency when compared to their peer companies.

9.4.2.1 Electricity Transmission

Fingrid is the transmission system operator in Finland, its efficiency is assessed in a comparative benchmarking study with other European transmission network operators. The efficiency assessment results in an efficiency score and an efficiency improvement target. According to the benchmarking study, the transmission network operator has been efficient.

Therefore, the TSO’s efficiency target consists only of comparing its own controllable OPEX cost level with its controllable OPEX cost level in previous years. Controllable OPEX are for example materials, personnel expenses, cost of leasing, other external services.

For setting the allowed controllable OPEX for the first year of the regulatory period, it is set equal to the average of the previous four years. This is referred to as the reference controllable OPEX. In the subsequent years of the regulatory period, the allowed controllable (reference) OPEX is indexed with the inflation (change of CPI) and changes in network volume. The network volume is a composite variable that comprises the length of overhead lines and the number of substations.

The efficiency gains (incentive impact) results from the difference between the reference controllable OPEX and actual controllable OPEX in the same year. These are calculated annually. If the TSO performs better than the reference controllable OPEX in a given year, then these efficiency gains are retained by the TSO.

The incentive impact is capped at 5% of the reasonable return of the respective year. This means that a difference between the actual and reference controllable OPEX higher than 5% will have no impact on the calculation of the adjusted actual operating profit.

9.4.2.2 Electricity Distribution

Middle/Low Voltage Distribution (<110 kV)

The efficiency assessment for distribution network operators (middle and low voltage) is based on a comparative efficiency analysis (benchmarking) using the StoNED (Stochastic Non-smooth Envelopment of Data) method comprising of the Finnish distribution network companies. The input variables used in the efficiency analysis include the controllable OPEX and replacement values of networks. These input variables are treated separately i.e., are not added together for the efficiency assessment. Furthermore, the controllable OPEX is modelled as a variable input, which the efficiency target is aimed at (cost minimisation). The replacement value is modelled as a fixed input which is a subject to optimisation. The output variables are the volume of distributed electricity, network length, number of metering points, regulatory outage costs and an operating environment variable (connections / metering points ratio). The ratio takes into account the higher costs resulting from a less-populated operating environment. It describes the proportion of the metering points connected to the network through the same connection. The ratio is low for distribution network operators operating in urban conditions and close to 1 for network operators operating in sparsely populated areas.

Data from the period 2012-2018 were used for the benchmarking analysis for the fifth regulatory period.

The efficiency analysis estimates the efficient levels of controllable costs for the individual network operators for the first year of the regulatory period. The controllable OPEX is also adjusted with the consumer price index to consider inflation for each year of the regulatory period.

High Voltage Distribution (110 kV)

The approach used for high voltage distribution resembles the one used for the TSO. The network operator's efficiency only consists of comparing an operator's cost level with its own cost level in previous years. The allowed controllable (reference) OPEX for the first year of the regulatory period is set equal to the average of the previous four years. In the subsequent years of the regulatory period, the allowed controllable OPEX is calculated by indexing the reference OPEX from the previous year with the inflation (change of CPI) and changes in network volume. The network volume is a composite variable that comprises the length of overhead lines, length of underground cables and the number of substations.

The efficiency gains resulting from the difference between the reference and actual controllable OPEX are retained by the network operators. Based on consultation with the DSOs and decision of the NRA the incentive impact is capped at 20% of the reasonable return of the respective year.

9.4.3 Quality incentive

The quality incentive aims to improve the network's reliability, i.e., to reduce the costs of network outages to end-users. The quality incentive is based on the disadvantage caused by an outage based on the number and duration of outages as well as the predetermined unit prices (€/kWh) of outages.[60] The unit prices of outages were determined based on studies commissioned by the NRA.[61]

The effect of the quality incentive is calculated by deducting the actual outage cost from the reference level of outage costs. The network operator's average regulatory outage costs from the two previous regulatory periods (2012-19) are used as the reference level for the fifth regulatory period.

The effect of the quality incentive cannot exceed 15% of the distribution network operator's reasonable return in the respective year. For transmission, the impact of the quality incentive cannot be higher than 3% of the TSO's reasonable return in the respective year.

The 15% and 3% apply both up- and downwards (symmetrical (i.e., can involve a reward or a penalty).

9.5 CAPEX Integration/Investment Incentives

According to the Finnish Electricity Market Act, network operators must submit network development plans to the NRA bi-annually. The plans should include activities which demonstrate how each network operator plans to improve and maintain quality of supply.[62]

60 In the fifth regulatory period (2020-23), the number and duration of planned and unexpected outages, the number of high-speed auto-reclosers, and the number of time-delayed auto-reclosers are considered from medium-voltage (MV) and high-voltage (HV) distribution networks when determining the outage costs.

61 Separate studies were commissioned for determining outage costs for transmission and distribution respectively.

62 In summer 2021 amendments to the Finnish Electricity Market Act were made and in addition to the earlier quality of supply requirements, the legislation now includes requirements for network operators to do investments in cost-effective ways and to consider possibilities of using flexibility services instead of grid investments.

The goal of the incentive on investments is to encourage network operators to make their investments in a cost-efficient manner. The NRA calculates investment costs by using its own estimations of the unit prices of network components. The standard unit price is applied for different types of network assets such as overhead and cable lines, transformers. The unit prices (as well as asset lifetimes) of different asset have been determined in a survey conducted by the NRA in 2014 and 2015.[63] The network operators responded to the survey.

For the fourth regulatory period (2016-2019), the unit prices were updated using the consumer price index. The updated unit prices are used in the current regulatory period (2020-2023).

This means that the allowed CAPEX is based on the standard unit prices for the different asset categories as defined by the NRA. If network operators can invest more efficiently than implied by the unit price, they will obtain an investment allowance (based on the unit price) which is higher than the actual CAPEX spent. Accordingly, the operators will be able to earn additional gains by receiving compensation for depreciation allowance that are based on larger expenditures than what have, in reality, been incurred.

9.6 Innovation Incentives

The objective of the innovation incentive (applicable to both electricity transmission and distribution) is to encourage the network operators to seek innovative technical and commercial solutions.

The NRA encourages the DSO to make active efforts in research and development by deducting reasonable research and development costs in the calculation of realised adjusted profit. The regulatory framework does not explicitly determine the specific steps and competences related to the qualification of innovation activities. However, it clearly states that the companies' activities must focus on projects directly related to the development of new knowledge, technology, products or methods. The results of the projects must be publicly available to be accepted for this incentive. The innovation incentive cannot exceed 1% of the network operator's total allowed revenues over the entire regulatory period.

9.7 Supplementary Incentives

The NRA applied a security-of-supply incentive to the distribution network operators. This incentive was introduced in the fourth and fifth regulatory periods to stimulate the operators to meet the security of supply criteria in a cost-effective way. According to the Electricity Market Act, interruptions may not last over 6 hours in urban areas and 36 hours in rural areas. Therefore, some distribution network operators will have to make extensive replacement investments and perform maintenance measures.

The incentive compensates distribution network operators for unexpected losses that result from the need to retire some parts of their network assets earlier and for any maintenance costs incurred and precautionary measures taken to reach the criteria (e.g., forestry activities that decrease the risk of interruptions due to falling trees).

As a result of amendments to the Electricity Market Act, the NRA removed the security-of-supply incentive from the methodology, to reflect the fact that the deadline for the distribution operators to meet the legal requirement referred above (in terms of interruption duration) was extended from 2028 to 2036 (Finish Government, 2021).

63 For example, €/km and corresponding lifetime. Unit prices have been determined with reference to market data.

9.8 Role of Forward-Looking Estimations

As the CAPEX assessment applies unit cost analysis, The NRA applies forward-looking elements. The planned investments are estimated based on the forecast of the physical and financial volume of assets that the network operators will need to replace in the future. The forecast is done by the network operators.

Furthermore, the NRA uses an indexation approach that adjusts the controllable OPEX for inflation, efficiency changes and network volume changes. This means that any planned changes in volume is reflected in the OPEX forecast which is then used as input in the efficiency analysis.

In this way the regulator retains the link between the allowed revenue and the efficient cost needed to accommodate the changes in the obligations of the regulated companies and to continue providing a reliable network service.

9.9 Regulation and Energy Transition

A long-term objective in Finland is to be a carbon-neutral society. The European Green Deal and Fit-for-55 packages have accelerated the achievement of climate targets. Alongside electrification, the use of hydrogen is widely seen as a key solution for a clean power system.

The TSO’s operations are impacted by four trends, which are climate change and the transformation of the energy system, security of supply and electricity dependency, globalisation and responsibility, and digitalisation The TSO’s grid investments are expected to total 3 billion euros in the next ten years to address energy transition and carbon neutrality goals of Finland.

In 2021, Fingrid invested EUR 178.6 million of which investments to the grid were EUR 166.3 million. This is an increase of EUR 29 million from 2020. Fingrid has published a draft of Finland's electricity system vision. The vision contains four scenarios for the development of electricity production and consumption for 2035 and 2045. In order to enable a forward-looking approach, scenarios have been drawn for the years 2035 and 2045. The network investments needed over the next ten years are described in the network development plan published in autumn 2021.

According to the submitted Grid Development Plans of the distribution network operators, plans for replacement investments for the electricity distribution grids during 2014 - 2036 are worth about EUR 9.7 billion, of which 1/3 will be used to increase quality of supply. Furthermore, independent transmission / distribution network operators sponsored studies concluded that the electricity network has a critical role in achieving the climate driven target. This, and other factors, has resulted in the Finnish DSOs to implement renewable energy into their strategy and grid development plans.

When it comes to the regulation of the electricity network, the NRA has developed details of the methodology to incentivize more innovation and investment in the networks. Furthermore, the NRA decided to use 0% general productivity target for the last two regulatory periods in order relieve the future cost burden of the network operators caused by mandatory new tasks (e.g. hourly metering and remote reading for energy metering).

10 APPENDIX A1: NORWAY

Background

Norway has one TSO (Statnett) and more than 100 electricity DSOs that own and operate the lower voltage tiers of Norway's electricity grid. The Norwegian Energy Regulatory Authority (NVE-RME) is the power industry regulator in Norway. Network regulation in Norway was a rate-of-return regulation until 1996. Since 1997, NVE-RME has been using models based on incentive regulation. The basic element of the regulatory system is that the allowed revenues, i.e. the costs that are recognised for recovery, are to some extent separated from actual costs. Through a system of incentives, NVE-RME aims to encourage the network companies to reduce costs and improve efficiency.

Revenue Setting and Efficiency Analysis

In order to set the revenue caps, the NRA applies comparative benchmarking for the DSOs. The TSO Statnett is benchmarked against its own historical cost performance.

The benchmark analysis of the distribution networks is conducted by NVE-RME on the basis of data envelopment analysis (DEA). DEA is used separately for local (22kV-240V) and regional distribution (132kV-33kV) and reviews total costs. The total costs consist of the OPEX, cost of energy not supplied (CENS), return on assets, depreciation and cost of network losses. The cost of network losses is calculated by multiplying actual network losses with a reference power price. The cost of network losses is considered only for local distribution (22kV-240V), not for regional distribution (132kV-33kV).

The output factors used for the benchmarking for the local distribution include the number of customers, length of high voltage network and number of substations. For the regional distribution, the output factors include the weighted values of the overhead lines, ground cables, sea cables and stations (NVE-RME, 2017). In order to establish the weights, the NRA first estimates the standard unit costs of the specific asset group. The standardised costs are then multiplied by the relevant unit (e.g. km line) and then summed up to a single figure that represents the weighted value of the respective asset group.

The efficiency scores derived in the benchmarking analysis are adjusted to account for environmental factors outside of the companies' control in order to improve the quality of the comparison. This is done by regressing the efficiency scores from the DEA analysis on the factors explained below (z-factors). The calculated coefficients in the regression analysis are subsequently used to adjust the efficiency scores. The efficiency scores are denominated in percentage. The efficiency frontier is established by DEA. Efficiency is defined as the ratio of the weighted outputs and inputs whereas the weights are automatically defined by DEA. The most efficient companies are 100 % efficient by definition.

The z-factors for the local distribution networks include coniferous and mixed forest, Factor 1 (deciduous forest with a high growth, injection of electricity production, slope and snow that sticks to trees), Factor 2 (strong wind near the coast, salting and share of sea cable), and Factor 3 (icing, snow, low temperature and strong wind). For the regional distribution network, until 2022 only one compounded z-factor was used. This factor reflected the average inclination and share of overhead lines in coniferous forest. In the beginning of 2023 this z-factor was abolished due to a lack of statistical significance.[64]

Each network operator receives a revenue cap (revenue allowance) to cover its local network and another allowance for its regional network (if any).

By definition, only the companies on the efficiency frontier of the DEA are 100% efficient and should consequently earn a "normal" return. However, the NRA has the opinion that the regulated sector in total should earn a 'normal' return. Therefore, the NRA calibrates the results and adjusts the efficient costs (cost norms) to ensure that on average the companies will be able to cover their costs including a normal return. This calibration is executed by comparing the actual costs, including a normal return on equity, for all the benchmarked companies with their efficient cost levels. The

64 The entire system is described extensively in Norwegian language in Økonomisk regulering av nettselskap - NVE. A paper that provides information on the z-factors can be found under 3425691 (nve.no).

differences are aggregated and shared between the benchmarked companies based on the size of their regulated asset base.

The revenue cap (revenue allowance) of a network operator in year t is a weighted average of its cost norm and its actual historic costs (cost base), both established with data from t-2. In the current price control, 70% of the revenue cap is determined by the cost norm and the remaining 30% is set equal to the cost base. The partial coupling to the actual costs is used to account for potential modelling errors, incompleteness of the model specification and factors that are outside of management control.

The cost base is calculated as the sum of the $OPEX_{t-2}$ adjusted for two years of inflation, $CENS_{t-2}$ (cost of energy not supplied) adjusted for two years of inflation, $depreciation_{t-2}$, return on assets (RAB_{t-2} * $WACC_t$) and cost of network losses (product of the actual network losses in t-2 and with a reference power price). Depreciation is determined by assuming a linear profile over 30 years. The NRA sets the WACC (weighted average cost of capital) to calculate the return on capital for each company. The WACC is the same for all network operators.

The NRA adjusts the final revenue cap ex-post to account for the difference between reported costs in t-2, and actual costs in year t.[65]

Quality of Supply Incentives

The NRA applies quality incentives in the revenue cap. The cost of energy not supplied (CENS) is included in the cost base. The CENS is determined as a function of the types of customers (households, farmers, public service, industrial, and commercial (trade, service)), duration of the outage, timepoint (time of day, week and year for an outage) and whether the outage was planned and notified or not. The parameters of the functions are estimated by means of customer surveys. The parameters are updated after some years however the regulatory framework does not provide a specific timing for such updates. The last update of the CENS parameters took place in 2017.

As the cost base is used to calculate the cost norm, it also influences the cost norm and the final revenue cap. Companies are therefore encouraged to balance their quality and efficiency performance. The NRA applies also guaranteed standards of performance for quality of supply. Failure to comply with the guaranteed standards is generally penalised. The penalty payments are not considered when calculating the revenue allowances).

Investments and Investment Incentives

One of the main ideas of the regulatory scheme in Norway is to leave the choice between OPEX and CAPEX fully to the regulated companies. Hence, there are no special arrangements for investments.

There have been views that the calibration mechanism described above and used to ensure cost recovery including a normal return may provide an extra incentive towards CAPEX. This is because the mechanism applies regulated asset base of the network operators in the calibration process. However, in practice, such a bias towards CAPEX is uncertain by nature. It would be likely weaker than a simple calculation might indicate because the regulation is not fully static – it is adapted and adjusted over time.

Innovation and Sustainability (Decarbonisation) Incentives

For some years, innovation activities have been encouraged by an additional allowance of at most 0.3% of the allowed revenues. This R&D allowance can be used for participation in R&D projects publicly funded by the Research Council of Norway, and/or other R&D activities approved by the NRA. An example of the latter is an industry-wide development effort aimed at digitalisation of the DSOs in Norway. The R&D allowance will not in itself impact future efficiency scores unless the DSO changes behaviour and non-R&D spending as a result of the R&D activity.

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65 The capital cost is adjusted by the sum of (RAB_t - RAB_{t-2}) * WACC + (DEP_t - DEP_{t-2}). DEP stands for depreciation. Other costs are adjusted for differences between the forecasted and planned inflation measured by the CPI.

There are essentially two criteria applied by the NRA. First, the innovation activity must address issue relevant for the network operator. Second, the R&D activity must qualify for R&D funding from the dedicated institutions such as the Research Council of Norway, Enova and Innovation Norway.[66]

66 Enova is a state body aimed at supporting and improving energy efficiency.
Innovation Norway focusses more on development and less on research activities when compared to the Research Council.

DNV

11 APPENDIX A2: AUSTRALIA

Background

The National Electricity Law provides the foundation for the regulatory framework governing electricity networks in Australia's national electricity market (NEM). The Australian Energy Regulator (AER) regulates the electricity networks and gas pipelines in all jurisdictions. These are New South Wales, Victoria, Tasmania, South Australia, and Queensland. There are five electricity transmission network operators (one in each state) and 13 electricity distribution network operators in Australia's NEM.

In the following paragraphs the regulatory framework for New South Wales is presented.

Revenue Setting

The current regulatory price control period for electricity transmission is 1 July 2018 – 30 June 2023 and for distribution it is 1 July 2019 to 30 June 2024 (Transgrid, 2022).

The regulation is incentive based with revenue caps determined using a building blocks approach. The building blocks are operating expenditures (OPEX), return on assets (RAB x rate of return), depreciation and tax allowance.[67]

Before the start of a regulatory period, the network operators submit their regulatory proposals to the NRA. This entails an overview of planned (forward-looking) costs for the next regulatory period. This includes the planned investments and the OPEX required for the next five years. The regulatory proposal also includes all the relevant supporting information, the methodology used to develop the forecast, and any assumptions applied. As part of the process in developing the regulatory proposal, the network operators consult with stakeholders and customers to seek their input and their priorities. Safety, affordability, encouraging renewables, reliability, bill itemisation, good customer service and communication and innovative technologies were some examples from the 2019-2024 regulatory proposals. External technical/engineering experts are involved in the preparation of the regulatory proposals. This is however more relevant for investments.

The NRA has provided Guidelines on their approach of how they assess the regulatory proposals (AER, 2022c). The network operators follow the approach set out in these Guidelines to develop their forecasts. The network operators develop forecasts for demand, energy consumption, customer numbers and number of smart meters as part of the planning process. The methodology and approach of the forecast should also be included in the regulatory proposal.

Ex-ante Reviews (OPEX and CAPEX)

Once the regulatory proposals have been submitted to the NRA, the NRA conducts an ex-ante review. A combination of qualitative and quantitative assessment techniques is applied. These techniques include:

- **Trend analysis (OPEX / CAPEX):** the NRA compares the planned OPEX/CAPEX and volumes with historical levels. Where planned OPEX/CAPEX and volumes are materially different from historical trends, the NRA seeks to understand the reasons for these differences.
- **Benchmarking (OPEX/CAPEX):** The NRA compares the performance of a distribution network operator with that operator's past performance and the performance of other network operators using a range of economic benchmarking techniques including data envelopment analysis (DEA) and regression analysis. This helps to assess whether a network operator's CAPEX/OPEX forecast represents efficient costs. The NRA uses benchmarking to obtain its forecast of future productivity changes in assessing OPEX forecasts.
- **Base-step-trend (OPEX):** the NRA assesses the assumptions and analysis that the network operators have applied based on the base-step approach. A base year (the fourth year of the previous regulatory control period) is selected for developing the OPEX forecast. The base step approach entails first a review any

67 The rate of return is defined in nominal terms (the so called "vanilla" WACC).

adjustments that were then made, for example to remove any non-recurrent (one-off) costs to ensure that the forecasts reflect the costs required to run the business as usual each year. Then, the base year OPEX is adjusted to reflect the following:

- Output growth: Economic analysis is used to determine the relationship between the forecast changes in outputs (customer numbers, line length and demand) and OPEX.
- Real Price growth: to reflect the expected increase in the future price of inputs.
- Productivity: OPEX is adjusted for productivity growth. This reflects the productivity improvement for network operators to improve their efficiency over time because of technological change

- **Category analysis (CAPEX):** CAPEX is split into a number of categories to help assess the CAPEX forecast and the proposals of the network operators. These categories consist of replacement CAPEX, network augmentation, connections and customer driven works CAPEX, and non-network CAPEX (e.g., IT & communications (ICT), property, fleet, buildings & property, plant & equipment).[68] The assessment by the NRA uses trend analysis and also unit costs. This can be for example AUS$/line length.
- **Top-down analysis (CAPEX):** The NRA applies a number of techniques such as trend analysis (as explained above), predictive modelling,[69] and technical / engineering reviews. Furthermore, the NRA considers how a network operator has produced its CAPEX forecast. This includes looking at the decision-making process that determines the scope and inclusion of each CAPEX program and project that contributes to the forecast. The NRA may compare a network operator's approach with those of other network operators and look further into those areas that do not align with good practice.
- **Regulatory Investment Tests (CAPEX):** These are applied to establish whether forecast CAPEX is prudent and efficient. The NRA examines the forecasting methodology and underlying assumptions applied by the network operator. For transmission and distribution, regulatory tests are for projects that exceed the value of AUS$ 7 million (approximately 4.5 million €) and AUS$ 6 million (approximately 3.86 million €) respectively.
- **Other supplementary methods:** Other assessment factors / information are considered including safety and reliability statistics (SAIDI and SAIFI), internal technical information / reviews, external consultant support, and any miscellaneous information provided by network operators.

Furthermore, the NRA considers certain programs and projects in forming a view on the total CAPEX, they do not determine which programs or projects a network operator should or should not undertake. The approach is to approve an overall ex-ante revenue allowance that includes an assessment of what they find to be a prudent and efficient total CAPEX forecast.

CAPEX Incentives: Ex-post CAPEX Review

At the end of the regulatory period, the NRA conducts an ex-post review of the efficiency and prudency of CAPEX. The review is done to ensure that only CAPEX that is deemed efficient is rolled into the opening RAB of the next regulatory period. The NRA assesses actual CAPEX spending against the allowed CAPEX. The NRA uses the same techniques to conduct an ex-post assessment as for ex-ante assessments of CAPEX.

A key question of the ex-post review is if an overspend towards a network operator's CAPEX allowance is significant. Consideration is also given to whether there is a cumulative overspend over the regulatory period. The NRA may also conduct a high-level comparative analysis to support their assessment. This supplementary information assesses how the network operator has performed on CAPEX compared to similar network operators. For example, if similar network

68 Augmentation CAPEX is typically triggered by a need to build or upgrade network assets to address changes in demand for distribution services or to maintain quality, reliability and security of supply.

69 The NRA have developed 2 models. A REPEX model (condition-based modelling to forecast asset replacement activities and the AUGEX model an asset utilisation model to forecast network augmentation requirements.

operators faced the same exogenous factors, then a comparison could indicate how well each network operator has responded to these factors. If no significant concerns emerge from this high-level assessment, then no further assessment of CAPEX efficiency and prudency is required. However, a network operator's actual CAPEX performance might require further assessment. The further assessment considers other aspects such as the network operator's management and planning tools and practices, information related to changes to demand, indicators of service performance, and specific technical and financial project aspects.

For projects that have been subjected to ex-ante regulatory investment tests, an ex-post review is conducted. As part of the review, it is assessed as to whether the network operator has applied appropriate project management plans and processes, project delivery controls, procurement strategies, and project governance.

To support the ex-post reviews, the network operators are required to annually submit information on the progress of the projects. The NRA assesses the data collected during the previous regulatory period in the review process. Based on this analysis the NRA can decide to exclude or accept actual CAPEX ex-post. The ex-post review is conducted at the end of each regulatory period. The inclusion or exclusion of CAPEX in the RAB is relevant for determining the allowed revenues for the subsequent regulatory period. Ex-post reviews are conducted for both general CAPEX and project-specific CAPEX.

To incentivise network operators to undertake efficient CAPEX, a capital expenditure sharing scheme (CESS) is implemented. This scheme rewards network operators that outperform their CAPEX allowance and penalises those that spend more than their CAPEX allowance. It also provides a mechanism to share efficiency gains and losses between the network operators and network users. Under the CESS a network operator retains 30% of an underspend or overspend, while network users retain 70% of the underspend or overspend. The general application of the CESS involves calculating the net present value of all efficiency gains and losses for each year of the regulatory period and then the total efficiency gain/loss is calculated for the whole regulatory control period. The sharing factor is applied to the total efficiency gain/loss to calculate network operator's share of the gain/loss.

Financing benefits/costs that accrue through the regulatory control period are also considered. This is to ensure that the power of the incentive is the same in each year of the regulatory period, the CESS considers any benefits or costs that have already accrued to the network operator during the regulatory period. This is the financing benefit of the underspend or the financing cost of the overspend. The CESS reward/penalty is derived by subtracting the financing benefit/cost that has accrued from the network operator's share of the total efficiency gain/loss.

OPEX Incentives: Efficiency Benefit Sharing Scheme (EBSS)

The EBSS incentivises network operators to pursue efficiency improvements in OPEX by rewarding them for delivering services at a lower OPEX than the forecast allowance. The efficiency gains for the EBSS are shared 70/30 between the network users and the network operator. The EBSS does this by allowing a network operator to retain efficiency gains (or losses) for a total of six years, regardless of the year in which the network operator makes them. The benefit of operating expenditure underspends (or the cost of any overspends) is kept by the network operator for a set number of years. At the end of those years the savings (costs) are passed on to customers. For each year of the regulatory period, the difference between the allowed and actual revenues is calculated. If the actual revenue is less than the allowed, in simple terms this is an efficiency gain as shown in year 4 and year 5 in the following figure. After six years, the present value benefit is passed on to customers.

An example provided by the NRA illustrating the EBSS is shown in the following figure.

$M	Regulatory period 1					Regulatory period 2					Future
Year	1	2	3	4	5	1	2	3	4	5	
Allowance	100	100	100	100	100	95	95	95	95	95	95 p.a.
Actual	100	100	100	95	95	95	95	95	95	95	95 p.a.
Efficiency gain	-	-	-	5	5	-	-	-	-	-	Nil p.a.
Incremental efficiency gain	-	-	-	-	-	-	-	-	-	-	Nil p.a.
Carryover calculation											
Year 1		-	-	-	-	-					
Year 2			-	-	-	-	-				
Year 3					5	5	5	5	5		
Year 4					-	-	-	-	-		
Year 5						-	-	-	-	-	
Carryover amount						5	5	5	5	-	Nil on-going
Full benefit to network	-	-	-	5	5	5	5	5	5	-	Nil on-going
Full benefit to customers										5	5 p.a. Ongoing
Discounted benefit to network*	-	-	-	5	4.7	4.5	4.2	4.0	3.7	-	- Total 26.1 or 30%
Discountedbenefit to costumers										3.5	58.7 Total 62.3 or 70%

* Assume a real discount rate of 6 per cent

1. The saving from the prior yearis held by the networkfor a further five years
2. Then the saving passes to customer
3. After six years. the present value benefit is passed on the customers into perpetuity
4. The present value benefits are shared. With customers receiving 70 percent of the total

Figure 11: Example of EBSS

Source: AER

Other Incentives: Service Standards Performance Incentives Scheme (STPIS)

For electricity transmission, the STPIS consist of three components: a service component which acts as a key indicator of network reliability. A market impact component to encourage minimising the impact of outages on the dispatch of generation; and a network capability component that encourages to undertake projects that are beneficial to customers. The STPIS provides a financial incentive in the form of a reward/penalty to maintain and improve service performance.

For electricity distribution, the STIPS comprises a reliability of supply component, a customer service component and a guaranteed service level component. Through these components, a network operators' reliability of supply and customer service affect their allowed revenues. Reliability of supply is measured by – the frequency of interruptions (SAIFI) and the duration of interruptions (SAIDI). The customer service parameters are telephone answering, streetlight repair, new connections, and response to written enquiries.

For the guaranteed service level, payment is made by the network operator to a customer when the service performance to that customer does not meet a certain level.

Innovation Incentives

An incentive called the Demand Management Innovation Allowance Mechanism (DMIAM) is related to investments for managing demand.

The DMIAM has two elements, the first is the Demand Management Incentive Scheme, the second is the Demand Management Innovation Allowance. The objective of the Demand Management Incentive Scheme provides an incentive to network operators to undertake efficient expenditures on relevant non-network options and alternative solutions to manage network demand. Examples of non-network options for demand include energy efficiency technology that can enable the use less energy and while still achieving the same outcome. Demand response is another example which means working with customers to reduce energy use during times of peak demand.

The Demand Management Innovation Allowance is for R&D funding applied to encourage experiments of innovative technologies to manage network demand. They should have the potential to reduce long term network costs and deliver on-going reduction in demand or peak demand.

The Demand Management Innovation Allowance provides a fixed amount of annual additional revenues. The maximum amount of the R&D allowance under this mechanism in a particular year is:

- $200,000,[70] plus
- 0.075% of the allowed revenues for that year for distribution. For transmission this is 0.1% of the annual allowed revenues.

An eligible project must meet certain criteria, such as being a project or program for researching, developing or implementing demand management capability or capacity. Furthermore, it should be innovative, in that the project or program is based on new or original concepts and involves technology that differ from those previously implemented. Some examples of demand management R&D that network operators have undertaken previously include:

- Using embedded generators and/or storage to provide network support, trialling mini grids and virtual power plants,
- Trialling different ways to deploy demand response/voluntary load curtailment,
- Using network solutions to manage demand on the network, by, amongst others, installing network assets like smart feeders, conductors and inverters.

Should the allowance not be spent at the end of the regulatory period, a carryover amount will be recovered from the network operator as a negative pass-through to network users. Any overspend of the allowance will be borne by the network operator.

70 This is corrected for inflation using the CPI index. Example: CPI was 2.0% in 2017/18 and 2.5% in 2018/19. At the start of the regulatory period in 2019, the base component would be $209,100 = $200,000 × (1.02) × (1.025).

12 APPENDIX A3 EMIRATE OF ABU DHABI (UNITED ARAB EMIRATES)

Background

In Abu Dhabi there are two electricity DSOs and suppliers, namely Al Ain Distribution Company (AADC) and Abu Dhabi Distribution Company (ADDC). For AADC and ADDC, price controls cover both distribution and supply. Abu Dhabi Transmission and Despatch Company (TRANSCO) is responsible for the development, operations and maintenance of high-voltage power and bulk water transmission networks within Abu Dhabi. The regulator is the Abu Dhabi Department of Energy (DoE).

The NRA sets multi-year price controls (revenue caps) defining the maximum allowed revenue (MAR) that each company can earn during each year of a typically four-year regulatory period. The first price controls were set for 1999-2002. This section is based on the regulatory framework applied in the period 2018-2022 (called RC1). The "First Regulatory Control" or RC1 (previously called "Price Controls") was set to apply for four years, from 1 January 2018 to 31 December 2021, but has been extended due to prevailing Covid-19 pandemic for another year to apply up to 31 December 2022.

Revenue Setting

In setting the price control, MARs are calculated by adding three main building blocks, namely operating expenditures (OPEX), regulatory depreciation, and return on assets. Capital expenditures (CAPEX) are funded by depreciation and return on assets. Regulatory depreciation is calculated by applying the straight-line method to the regulatory asset base (RAB) and an estimated weighted average asset life (40 years) to enable recovery of investments. The MAR is adjusted each year by the CPI and an X-factor.

The closing RAB for each year of the regulatory period is determined by rolling forward the opening RAB by adding any new CAPEX to be incurred during the year and subtracting the depreciation for that year. Only efficient actual CAPEX is ultimately allowed to roll-forward into the RAB. If any previous CAPEX is later found to be inefficient or additional CAPEX found to be efficient, adjustments are made to the RAB and the allowed revenue to allow recovery of only the efficient CAPEX.

OPEX

The network operators' OPEX allowances for RC1 were estimated using a hybrid method of top-down and bottom-up approaches prepared by an external consultant. The methodology includes the following steps, which are shown in Figure 12 and Figure 13 and the text below:

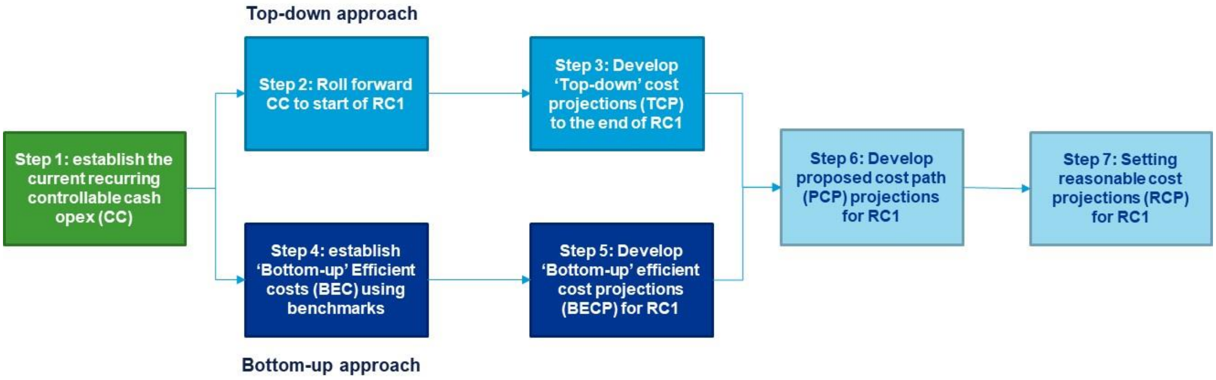

Figure 12: Steps to estimate OPEX

Source: DoE

1. Establish the network operator's base-level cost from 2016 (the latest audited actual costs). This is indicated as CO in Figure 13 and the blue line.

2. Roll-forward the network operator's base-level cost from 2016 to the start of RC1 (i.e., 2018).
3. Develop OPEX projections through to the end of RC1 based on the top-down approach with high-level estimates of both the cost-volume relationship and the expected productivity improvements. OPEX was assumed to increase by 0.7% for each 1% increase in demand growth. The expected productivity improvement was estimated at 3%-4% a year based on the sector companies' experience over 2010-2016 and evidence from other countries.
4. Establish the efficient level of the base year (i.e., 2016) costs using a detailed bottom-up analysis for efficient costs (BEC) – green line.
5. Starting with the base year costs from step 4, develop projections of efficient OPEX to the end of RC1 based on a detailed bottom-up assessment of costs. A frontier shift efficiency of 1% per year is also included in this bottom-up efficient cost projection (BECP).
6. Develop projections of reasonable, controllable OPEX during RC1 based on the top-down and the bottom-up cost projections. In addition, a transition path for the network operators from expected OPEX levels at the start of RC1 towards the efficient cost-levels at the end of RC1 based on step 5 is proposed. i.e., the proposed cost path (PCP) – dashed line.
7. Set the projections of reasonable total OPEX for RC1 by adding non-controllable OPEX (such as licence fees) to the OPEX projections.

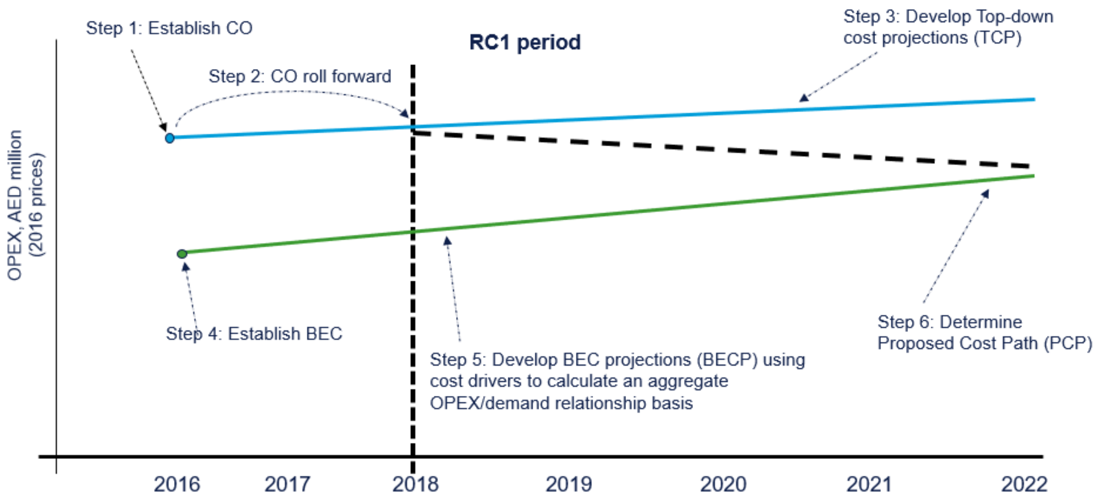

Figure 13: Seven step methodology to RC1 OPEX projections

Source: DoE

Ex-ante and ex-post CAPEX Reviews

For RC1, the NRA and network operators have agreed to introduce ex-ante CAPEX reviews for individual projects in order to incorporate a firm CAPEX (not provisional) allowance for future projects in the price controls (RAB and MAR). These reviews include justifications of the need of an investment, different options, design and budget for each project above a materiality threshold (e.g., 2%-5% of annual CAPEX).

However, the first such ex-ante CAPEX review faced challenges and resulted in only small firm CAPEX allowances, as the network operators' submissions / justifications were not robust / convincing. As a result, provisional CAPEX (without links to individual projects) was allowed to fund future CAPEX. The provisional CAPEX remains subject to a full ex-post efficiency review. Therefore, the current price control involves both ex-post and ex-ante CAPEX reviews.

Firm CAPEX allowances are also subject to ex-post review but only if the scope of a project changes or actual spending deviates from the allowance by more than 10%. The ex-post review focuses on key project processes including project management, strategic planning, design standard and policy, procurement and delivery.

Performance Incentives

Price controls for the network operators include performance incentives to encourage appropriate quality of service, outputs and performance. There are in total twelve incentives in five key areas of incentives, namely:

- Provision of high-quality information.
- Availability, security and quality of supply.
- Sustainability.
- Customer service.
- Reputational and monitored KPIs.

Companies are rewarded or penalised for improved, respectively deteriorated performances on an annual basis using pre-defined performance indicators. This financial reward or penalty is applied through an upward or downward adjustment to the allowed revenues via a Q-factor, often following verification of performance by an independent technical assessor. For each of the twelve incentives the maximum bonus or penalty is capped at 0.5% of the annual MAR. In addition, there is an overall cap on incentives of 4% of a network operator's annual MAR (i.e., excluding pass-through costs).

Table 5 below summarises all these incentives and lists the targets for each of the incentives. For some incentives there is a so-called dead-band. If a network operator's performance ends up within such a dead-band, then it is neither rewarded nor penalised for its performance.

With regards to the provision of high-quality information, the targets are in the form of a specific date by which information must be submitted. A delay beyond the target date will trigger a financial penalty. For any submission on or before the target date in any year, a company will receive a lump-sum reward.

For other performance indicators (other than information incentives), the penalty or reward depends on an incentive rate, the target performance and the actual performance.[71] The performance target for a given year is generally based on the company's actual performance in the preceding year.

The reputational and monitored KPIs do not include any financial bonus and/or penalty.

71 Where a performance indicator with a lower value than the target is considered a better performance (e.g., SAIFI, SAIDI, distribution losses): Q = Incentive Rate x [(Target performance – Actual performance)/ Target Performance] x 100. However, for performance indicators where a higher value than the targets is considered better performance (e.g., DSM), the signs in the above formula for Q will be reversed. That is: Q = Incentive Rate x [(Actual performance – Target performance)/ Target Performance] x 100.

Table 5: Summary of performance incentives

Area of incentives	Indicator	Target /Dead-band	AADC	ADDC	TRANSCO
Provision of high-quality information[72]	Separate business account	30 April	✓	✓	✓
	Annual information submission	31 October	✓	✓	✓
Availability, security and quality of supply	Interface metering	0.95-0.96 (dead-band)	✓	✓	✓
	SAIDI	Previous year's performance/ glide path target	✓	✓	
	SAIFI	Previous year's performance/ glide path target	✓	✓	
	Distribution loss reduction	Previous year's performance	✓	✓	
	Unsupplied energy	Penalty based on VOLL[73], bonus if no unsupplied energy			✓
	System dispatch costs	Previous year's performance			✓
Sustainability	Demand side management[74]	6%-10% (dead-band)	✓	✓	
Customer service	Customer complaints	Average performance in 2017 and 2018	✓	✓	
Reputational and monitored KPIs	Transmission system availability	NA			✓
	Financial performance ratios	NA	✓	✓	✓

Source: DoE RC1 final proposal

72 Information incentive penalties will only be triggered following repeated and consecutive failure to comply (two or more consecutive years).
73 For unsupplied energy, the incentive rate is the value of lost load (VOLL).
74 Based on the actual savings directly attributed to/measured from DSM activities in consumption per capita.

13 APPENDIX B SUMMARY TABLE

This table provides a summary of the regulatory instruments applied in the investigated countries and a summary of the purpose and effectiveness.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Efficiency Analysis	Efficiency Incentives	• Australia: NRA uses economic benchmarking in assessing OPEX forecast. • Great Britain: TOTEX benchmarking applied. • Germany: Total cost benchmarking applied. • Norway applies total cost benchmarking of DSOs for many regulatory periods. • Finland: applied efficiency analysis for DSO	• Efficiency analysis can be applied to estimate the efficiency of the network operators and set efficiency improvement targets. • Germany: The NRA evaluated the performance of the incentive regulation after two regulatory periods and observed an improvement in network operators' efficiency. The average efficiency of electricity DSOs increased from 92.2% to 94.7% from the first to the second regulatory period. For the third regulatory period, the average efficiency score is 94.1%. • Norway: A study performed by Amundsveen and Kvile (2017) indicated that incentive schemes with strong incentives for efficiency have contributed to increased productivity in Norway.
Regulatory period	Efficiency Incentives	• Germany and Australia: 5-year regulatory period. • Great Britain and Italy: use 8 years. Great Britain changed back to a 5-year regulatory period for RIIO-2. • Abu Dhabi, Belgium and Finland:4-year regulatory period.	• In the investigated countries, a regulatory period from four to eight years is used. • The main justification is that a longer regulatory period provides more stability and sufficient time for the companies to improve their efficiency.
Sharing Mechanism	Efficiency Incentives / Investment Incentives	• Great Britain: Sharing mechanism (TOTEX) are applied for transmission and distribution price controls. • Australia: applies sharing mechanisms for OPEX (EBSS), and CAPEX (CESS) in combination with an ex-post CAPEX review.	• Sharing mechanisms can be applied to efficiency gains/losses in OPEX, CAPEX or TOTEX • Great Britain: The TSOs reported a TOTEX underspend close to £3.77 billion (or 20%) for RIIO-1. Differences vary between the DNOs in actual TOTEX spending, with the majority of the DNOs' underspending from 2015 to 2020, ranging from a 4% overspend to a 13% underspend. • Australia: The sharing schemes applied has been effective. According to the NRA, based on the data collected so far it strongly suggest that the CESS has worked well to provide incentives for the network operators to only incur efficient CAPEX. The NRA attributes this as the result of the development of the regulatory tools over the years used to assess and determine the network operators' CAPEX forecasts.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Efficiency Carry-Over	Efficiency Incentives / investment Incentives	• Australia (OPEX) and Italy: Efficiency carry-over is applied.	• Efficiency carry-over can be considered as an extension of the sharing mechanisms. • When preparing for the following regulatory period, an NRA can determine to what extent the efficiency gains carry over to the next regulatory period. • Carry-over mechanisms are applied to strengthen the incentive to improve ongoing efficiency, not just for the current regulatory period. • Australia: The NRA considers that the sharing and carryover scheme has successfully driven OPEX efficiency gains in conjunction with the revealed cost OPEX forecasting approach in the ex-ante reviews.
Ex-ante CAPEX review	Efficiency incentives / investment incentives / forward-looking scheme	• Abu Dhabi: The NRA decided to introduce ex-ante CAPEX reviews in 2018-2022. However, the companies were not able to provide sufficient information and the NRA did not provide “very detailed guidance” and “a suitably long implementation period” to enable the companies to understand, implement and comply with an entirely new process. • Great Britain and Australia: the network operators provide their CAPEX forecast in their business plans / regulatory proposals.	• Investments can be integrated ex-ante or ex-post in the regulatory asset base (RAB). In the first case the NRA agrees ex-ante on the capital expenditures allowed to be included in the RAB before the start of the regulatory period. • Abu Dhabi: The NRA decided to provide further flexibility by planning an interim ex-ante review in 2019 and, if necessary, resetting the ex-ante allowances for CAPEX. • Great and Australia: The TSO/DSOs submit their CAPEX plans to the NRA. The NRA assesses these plans using combination of assessment methods. The NRA assesses CAPEX ex-ante using a combination of cost assessment techniques. • Overall, the continued use of ex-ante reviews as demonstrated in Australia and Great Britain indicates that they have been considered effective. In these two countries, the NRAs have developed and improved their approaches over time for assessing CAPEX and also focused on encouraging the network operators to provide good quality forecasts.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Ex-post CAPEX Review	Efficiency incentives / investment Incentives	• Australia: The network operators report their actual CAPEX and supporting information to the NRA. • Abu Dhabi: until 2018, the treatment of CAPEX was based on an ex-post assessment of efficient CAPEX only.	• Ex-post CAPEX review assesses the actual expenditure of the network operators at the end of the regulatory period. The NRA assesses the efficiency of the actual expenditure incurred and prevent allowed but unused investment costs being rolled into the RAB. • Ex-post CAPEX reviews can provide positive incentives to the companies to execute to their best of their ability the projects according to the approved plans. • Australia: This CAPEX ex-post review is a thorough process that needs a dedicated amount of effort and expertise. To support the ex-post review, the NRA also draws on the expertise of engineers and other external consultants to derive the ex-post adjustments • Abu Dhabi: CAPEX was assessed based on an ex-post review only. Thus, CAPEX inefficiencies would be identified, and network operators would be penalised only after some years from initiation of CAPEX projects. To address this limitation, the NRA introduced forward-looking ex-ante review to CAPEX assessments.
WACC Mark-Up	Investment incentives / Innovation	• Italy: applies explicit investment incentives by allowing a temporarily higher rate of return for certain types of investment (including innovative solutions and technologies).	• While in in the short term a WACC mark-up is very effective in encouraging investments, in the middle and long term it may provide a strong bias towards inefficient allocation of resources and overcapitalisation. • For example, at the end of 2015, the Italian NRA decided to gradually phase out the WACC mark-up as it decided to move from input-based regulation to more output-based regulation.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Innovation Allowance/ Funding	Investment incentives / innovation	• Great Britain: Uses explicit instruments, namely the Network Innovation Allowance (NIA) and the Strategic Innovation Fund (SIF). The SIF is meant for high-value innovation projects (over £5m). The funding and the process to access the SIF is competition-based and a number of eligibility criteria must be met. The NIA focuses on projects to tackle challenges associated with delivering net zero greenhouse gas emissions. • Norway: An explicit innovation allowance as a percentage (0.3%) of the allowed revenues is used for funding innovation and R&D initiatives • Italy: An explicit premium to the regulatory WACC, to certain types of investments including innovative solutions and technologies • Australia: Demand Management Innovation Allowance Mechanism (DMIAM) is related to investments for managing demand. • Finland: An innovation allowance of max 1% of the network operator’s total allowed revenues over the entire regulatory period	• NRAs are recognising the need to adapt the regulatory framework to facilitate and encourage innovation and R&D in electricity networks. • A regulatory instrument to support innovation recognised in the regulatory framework can be regarded as a positive development. For the innovation instruments to be effective, a common feature is that the process is transparent and clear guidance on eligibility and criteria is provided by the NRA.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Quality incentive schemes	Efficiency / investment incentives with focus on quality performance	• NRAs in all investigated countries apply quality regulation incentive schemes • Germany: the quality incentive scheme incorporates caps on the penalties/rewards. • Italy: the quality incentive schemes apply caps on the penalties/rewards and dead bands.	• Under quality incentive schemes the company's actual performance is compared to quality targets for selected reliability indicators that measure continuity of supply. • As described below, the quality incentive schemes have been effective. • Italy: in 2021, the duration of interruptions for low voltage users has decreased to 62 minutes (from 86 in 2019). The number of long interruptions also decreased to 4.07 for low voltage users (from 4.62 in 2019). • Great Britain: since the beginning of RIIO-1 the Customer Interruptions have reduced by 15% and Customer Minutes Lost have reduced by 10%. • Australia: consumers have experienced fewer distribution network outages (i.e., improvement of the SAIFI) over the period 2011-2020. • Germany: since the introduction of a quality of supply incentive scheme in the second regulatory period (2014-2018), the SAIDI decreased from 12.28 (2014) to 10.73 (in 2020) and 12.7 minutes in 2021.
Network loss incentives	Efficiency / investment incentives with focus on network loss performance	• Germany and Italy: apply explicit incentives for electricity network losses incorporating a separate cost allowance into the allowed revenue. • Great Britain: the NRA has used network loss incentive schemes in the past. It plans to reintroduce a direct financial incentive on losses once smart metering data is available.	• Network operators are encouraged to reduce network losses through incentives based on a recorded reduction in their loss rate relative to a target. • In Italy there was a progressive reduction in network losses over the years 2015-2020.
Target Investment Incentives	Investment Incentives	• Italy: the NRA introduced incentive mechanisms to encourage the extension of transmission interconnection capacity. • Germany: incentive mechanism for congestion management costs • Belgium: incentives on market integration and enhancement of security of supply	• Some countries have opted to establish financial incentives to prioritise certain investments. • As a result of the incentive to encourage transmission interconnection capacity, the Italian TSO increased the cross-zonal capacities of four internal network boundaries by using different measures (for special protection schemes including RES controllability and dynamic line rating).

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Environmental Incentives	Investment Incentives	• Great Britain: the regulatory framework RIIO-2 have established specific outputs to achieve an environmentally sustainable network such as business carbon footprint, environmental scorecard, annual environmental report.	• NRAs may want to incentivise network operators to achieve specific environmental objectives. For instance, by providing financial rewards for meeting these objectives. • A review of RIIO-1 indicated that network companies have reduced their carbon footprint, and reduced emissions and network losses.
Business Plan Incentives (BPI)	Investment Incentives	• Great Britain: applies a Business Plan Incentive (BPI).	• The BPI encourages companies to submit robust forecast of costs in their business plans and an operator is rewarded (penalized) if its business plan does (not) meet certain minimum criteria. • Based on the NRA's assessment of the BPI, final approval of business plans showed savings of more than £2bn versus previous forecasts.
Revenue Adjustment Schemes	Investment incentives / cost recovery	• Germany: the regulatory account covers differences in capital costs (resulting from divergence between planned and actual investments), changes in the permanently non-controllable costs and differences between the allowed and actual revenue (resulting from divergence between planned and actual quantities). • Great Britain: applies volume drivers to adjust allowances in line with actual volumes.	• Revenue adjustment schemes are ex-ante rules that define how revenue allowances can be adjusted for differences between what has been assumed while setting the allowed revenues and what occurs in practice. • This instrument is effective in adjusting for differences between what has been assumed in setting the allowed revenues and what occurs in practice.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Interim reviews (or re-opener) / trigger mechanisms	Investment incentives/ cost recovery	• Great Britain: the net zero reopener enables the network operators to reflect and respond to when there are material changes in demand or cost. In such case, the NRA may adjust a company's allowances. • Germany: the hardship clause is a re-opener, which stipulates that revenues can be adjusted in case of unexpected events • Italy: there is a trigger mechanism that stipulates that the WACC is updated if the cumulated impact of updating individual parameters is above a pre-determined threshold (50bps).	• The interim reviews (or re-openers) allow an NRA to take account of costs related to certain events, such as significant external shocks or material changes in circumstances. • A trigger mechanism is an automatic adjustment of regulatory components that occurs if a certain parameter moves above or below a pre-determined threshold. • The re-openers and trigger mechanisms are an effective way to accommodate unforeseen changes and developments, especially with respect to the energy transition and meeting decarbonisation goals.
Indexation / Quantity Adjustment Factors	Investment incentives/ cost recovery	• Italy: RPI-X regulation applied to OPEX indexes the OPEX during the regulatory period to changes in consumer prices. • Great Britain: applies real price effects (RPE) indexation mechanism. • Great Britain: applies volume drivers to ensure adjustment of allowed revenues in line with actual volumes • Germany: quantity adjustment factors were applied in the first and second regulatory period for electricity distribution.	• Indexation of cost allowances reduces the risk to network operators from unanticipated cost rises. • The quantity adjustment factors link allowed revenues to selected cost drivers (energy demand, number of customers, length of network, etc). The allowed revenues are adjusted annually based on observed changes in the cost drivers. • Great Britain: the volume drivers are effective in for example managing the uncertainty associated with the amount of load-related CAPEX required to connect new generators and demand customers to the transmission network.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Menu Regulation	Investment Incentives	• Great Britain: Information Quality Incentive (IQI) mechanism (2009).	• The NRA proposes a menu of options with different levels of incentives corresponding to different levels of costs for the network operators. • Great Britain: the NRA considered that the IQI mechanism was beneficial in terms of encouraging network operators to submit accurate CAPEX forecasts. • However, there were also some concerns about the application of the IQI mechanism: o Perceived risk aversion by the DNOs which might lead to them consciously submitting forecasts in excess of their expected level of expenditure so that they receive a weaker incentive rate at the expense of a lower expected return. o If the NRA relies on a first round of business plan submissions to inform the baseline determinations for expenditure categories that are difficult to forecast, such as capital enhancement, the menu regulation will not induce network operators to provide accurate first-round submissions.
Incentive for Controlling and Prioritising Investments	Investment Incentives	• France: the NRA defines a four-year envelope which is an investment cap. The network operator has an incentive not to exceed this envelope, and therefore, to control its expenses and prioritise certain projects.	• The incentive consists of a cap on the investment volume and a penalty that applies if the cap is exceeded. • The incentive focuses on specific groups of investments caused by the connection of renewable energy and necessary renewal of the network.
End-of-life Incentive	Efficiency / investment incentives	• Portugal: The financial incentive consists of a capital cost allowance. • Spain: The financial incentive consists of an increased OPEX allowance.	• End-of-life incentives aim to prevent the replacement of network assets that have reached the end of their regulatory lifetime but for which the technical condition is still good. • Portugal: based on the NRA, the end-of-life incentive was effective in avoiding a direct link between the level of allowed revenues and the level of investment.
Incentive for the Provision of Data	Sector Coordination	• France: The NRA introduced indicators on compliance by the TSO, through deadlines for publication (or transfer) of data identified as a priority for participants. The NRA applies penalties for non-compliance with the deadlines.	• The provision of data infrastructure and the timely publication of high-quality data by network operators is of major importance for market participants that utilize this data.

Instrument	Area	Use in Investigated Countries	Purpose and effectiveness
Incentive for the Achievement of the Electricity Generated from Renewable Sources (RES-E) Targets	Investment Incentives	• Ireland: the NRA rewards network operators for the actions they have taken to achieve the annual RES-E targets.	• NRAs may use explicit incentives to encourage the network operators to facilitate the transportation of renewable electricity.
Stakeholder Engagement Incentive Mechanism	Sector Coordination	• Ireland: the NRA provides network operators with a financial incentive on the scope, quality, and outcomes/impacts of their stakeholder engagement activities.	• The objective of this incentive is to encourage the network operators to improve their engagement activities, i.e. how network operators understand and address the needs of stakeholders and how their input is used to improve network services. • Ireland: The Networks Stakeholder Engagement Evaluation (NSEE) panel evaluated the stakeholder engagement activities of the TSO (and DSO) over 2018 and 2019. According to the NSEE panel the process worked well. With the network operators receiving and implementing recommendations for improvements provided by the Panel.
Joint incentives	Sector Coordination	• Ireland: TSO/DSO joint incentive is meant to improve collaboration on security of supply/constraints. The NRA establishes maximum rewards and maximum penalties for the financial incentives.	• NRAs may decide to apply joint incentives on transmission and distribution network operators. • The purpose of such incentives is to provide effective signals to the companies to act jointly and align their activities in terms of planning, operation and innovation.

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