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Promoting efficiency with neutral operational/capital incentives under large uncertainty: A comparison of electricity distribution remuneration schemes

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Abstract

Decarbonization of the energy sector involves the proliferation of decentralized renewable generation, and the electrification of energy uses, such as transportation, heating and cooling, and industrial processes that require renovation and new investment in electricity networks. In this context, the combination of traditional investment in grid infrastructure with smart grid solutions is required to minimize costs for consumers. Because electricity distribution is a regulated monopoly, the efficient combination of both solutions critically depends on the incentives embedded in remuneration schemes of distribution companies. Regulatory bodies increasingly emphasize the need for operational/capital expenditure-neutral incentives, as a persistent bias toward capital-intensive investment in traditional grid reinforcement may hinder the deployment of smart grid flexibility-based alternatives. At the same time, in this context, growing uncertainty in future load growth requires adaptable network planning to put in value smart-grid flexibility solutions under the correct incentives given by distribution remuneration schemes.

This paper formulates a methodology to quantitatively assess how different distribution remuneration schemes: cost of service, revenue cap, and total expenditure with a fixed capitalization rate, impact the investment decisions of a profit-maximizing distribution company.

Our results show that the total expenditure with a fixed capitalization rate scheme, despite common belief among actual regulators, leads to cost misallocation, which, when combined with efficiency incentives, creates distortive investment signals. In contrast, the revenue cap scheme, if designed with a sufficiently high incentive rate, not only fosters efficiency but also mitigates the capital-intensive solutions advantage. Furthermore, once efficiency is properly incentivized, adaptable planning can deliver substantial savings and should be prioritized by regulators, following the shift from cost of service toward revenue cap with profit-sharing schemes.

Keywords

Electricity distribution remuneration; capital expenditure bias; flexibility; neutral incentives; investment under uncertainty

Abbreviations

ARR: Allowed rate of return; CAPEX: Capital expenditure; CC: Cost of capital; CEER: Council of European Energy Regulators; CoS: Cost-of-service; DER: Distributed energy resources; DSO: Distribution system operator; EV: Electric vehicle; IR: Incentive rate; LDC: Load duration curve MSC: Minimum system cost; OPEX: Operational expenditure; RAB: Regulated asset base; R&D: Research and development; TOTEX: Total expenditure; UK: United Kingdom; VoLL: Value of lost load.

Notation

Sets:

b: forecasted base scenarios without noise $\{1, \ldots, B\}$.

h: hours in the year $\{1, \ldots, 8760\}$.

s: forecasted scenarios with added noise $\{1, \ldots, S\}$.

t, a: years in the planning period $\{1, \ldots, T\}$.

Parameters:

ARR: allowed rate of return set by the regulator.
CC: actual cost of capital of the distribution company.
CR: capitalization rate under the TOTEX approach.
ENS_t^{ref}: reference for energy not served set by the regulator for the quality incentive (€).
$F_{s,t}^{act}$: amount of flexibility to activate in scenario s and year t (MWh).
$F_{s,t}^{res}$: amount of flexible energy to reserve in scenario s and year t (MWh).
FLT: lead time for flexibility (years).
$\mathrm{FR}^{\mathrm{Cost}}$: flexibility reserve cost (€/MW/h).
$\mathrm{FU}^{\mathrm{Cost}}$: flexibility utilization cost (€/MWh).
G^{inv}: investment required for grid reinforcement (€).
G^{ul}: useful life of the grid reinforcement (years).
$\mathrm{Pr_s}$: probability of scenario s.
R^{ul}: useful life of the slow money under the TOTEX approach (years).
RT_t: revenue trajectory set by regulator under revenue cap approach (€).
RT_t^{TOTEX}: revenue trajectory set by regulator under TOTEX approach (€).
$VoLL$: value of lost load (€/MWh).
Variables:
$dep_{s,t}$: depreciation cost in scenario s and year t (€).
$dep_{s,t}^{TOTEX}$: depreciation cost under TOTEX capitalization rules in scenario s and year t (€).
$ens_{s,t}$: energy not served in scenario s and year t (MWh).
$\mathrm{f_{s,t}^{act}}$: flexibility to activate in scenario s and year t (MWh).
$f_{s,t}^{res}$: flexibility to activate in scenario s and year t (MWh).
$fm_{s,t}$, is the value fast money in scenario s and year t.
$g_{s,t}$: binary variable equal to 1 if grid reinforcement is in operation at year t and scenario s, 0 otherwise.
$i_{s,t}^{G}$: binary variable equal to 1 if a grid reinforcement becomes operational sometime during year t in scenario s; 0 otherwise.
$om_{s,t}$: is the operation and maintenance cost in scenario s and year t.
$r_{s,t}^{F}$: binary variable equal to 1 if flexibility is reserved for scenario s and year t, 0 otherwise.
$rab_{s,t}$: value of the regulated asset base at the beginning of year t in scenario s (€).
$rab_{s,t}^{TOTEX}$: value of the regulated asset base under TOTEX capitalization rules at the beginning of year t in scenario s (€).
$sm_{s,t}$, is the value slow money in scenario s and year t.
$totex_{s,t}$ is the total expenditure, investments (i.e., CAPEX) plus OPEX, in scenario s and year t.

1. Introduction

Decarbonization of the energy sector involves the proliferation of decentralized renewable generation, and the electrification of energy uses, such as transportation, heating and cooling, and industrial processes that require renovation and new investment in electricity distribution networks [1].

In this context, the combination of traditional investment in grid infrastructure with smart grid solutions is required to minimize costs for consumers. The uptake of new technologies, such as digitalization and more distributed energy resources (DER) connected to distribution networks, involves new challenges and opportunities in network planning and operation. In addition to investment in traditional grid infrastructure, power transformers, and lines, smart grid solutions, including the procurement of flexibility[1] from DER through flexible connection agreements, local flexibility markets, or bilateral contracts, and network reconfiguration, and dynamic line rating, among others, offer new competitive alternatives to find optimal investment plans [3]. In this context, smart grid flexibility solutions can be leveraged to defer traditional

[1] Flexibility may be defined as "the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the energy system" [2].

network reinforcement and to accelerate connections of new users by better utilization of existing network infrastructure.

Electricity distribution is a regulated natural monopoly, and as acknowledged by the Council of European Energy Regulators (CEER) [4]: "The distribution system operator´s (DSO´s) decisions when planning, expanding and managing their networks are led by the incentives in the revenue/remuneration regime and direct regulatory requirements." So, the use of smart grid flexibility solutions by DSOs will depend on the incentives present in their remuneration scheme. Thus, regulatory frameworks and, in particular, remuneration schemes should be revisited to make sure that they incentivize optimal planning by a combination of smart grid flexibility solutions and traditional grid investment.

Flexibility solutions as a planning alternative to defer grid investment, offer the most value when uncertainty in planning scenarios is considered and adaptable wait-and-see strategies (i.e., real options approach) are used [5], [6]. This is especially important in the current context characterized by high uncertainty about the growth rate of electricity demand [7], where there is a risk of overinvestment in grid assets resulting in increased tariffs if lower demand scenarios materialize, while underinvestment may result in congested grids and delayed new users´ connections if higher demand scenarios materialize. There is a need for regulatory frameworks to evolve from deterministic investment analysis and move on towards a probabilistic approach with adaptable strategies [6].

Moreover, smart grid flexibility solutions mainly represent an operational expenditure (OPEX) for DSOs, for instance, an annual contract with an industrial consumer to procure consumption reductions at peak network utilization periods announced by the DSO. On the other hand, grid investments in distribution feeders or power transformers represent a capital expenditure (CAPEX) for DSOs. Both researchers [8], [9], [10], [11] and regulatory bodies like Ofgem [12], CEER [13], and the Danish utility regulator [14] have emphasized the importance of establishing neutral OPEX/CAPEX incentives in DSO remuneration schemes to promote overall system efficiency and remove barriers for innovative smart grid flexibility solutions.

The DSO remuneration schemes that set the DSO´s allowed revenues for a regulatory period of several years can be classified into ex-ante or ex-post approaches. The ex-post approach, also known as cost-of-service, presents a potential moral hazard as DSOs are not encouraged to pursue cost-efficiencies. That may result in excessive costs for network users [15]. The ex-ante approach that sets a trajectory for the allowed revenues along the regulatory period, i.e., multi-year revenue trajectory, encourages DSOs to pursue cost efficiency [8]. However, establishing an ex-ante revenue trajectory is not straightforward, as regulators face the challenge of information asymmetry. The ex-ante revenue trajectory may underestimate the cost-saving opportunities of the distribution company, thus resulting in allocative inefficiency and rent extraction by the DSO. This is known as the adverse selection problem [15].

A recommended approach is to combine both approaches, resulting in an ex-ante approach with an ex-post profit-sharing mechanism [15]. This multi-year revenue trajectory with a profit-sharing mechanism incentivizes the DSO to pursue cost-efficiency while sharing some of the savings with network users [16]. In this paper, this scheme is called a revenue cap. Still, this approach may present a bias toward CAPEX solutions because investments are capitalized and remunerated over time with an attractive rate of return, while this attractive rate of return does not apply to OPEX. A widely accepted practice among regulators believed to achieve incentive neutrality is the implementation of a fixed capitalization rate[2] that affects both CAPEX and OPEX. This remuneration scheme is known as the total expenditure (TOTEX) approach.

There is a need for a quantitative assessment of the actual incentives that the three previously presented remuneration schemes provide to DSOs when planning investment solutions in the presented context of competition and synergies between smart grid flexibility versus traditional grid solutions, and deep load growth uncertainty in decarbonization planning scenarios.

[2] Under TOTEX approach, the regulator fixes a capitalization rate for the regulatory period that affects both CAPEX and OPEX. The capitalization rate is the portion of expenditures that are capitalized (i.e., included in the regulatory asset base) and remunerated over time with the rate of return. This fixed capitalization rate is also known as fixed OPEX/CAPEX share abbreviated as FOCS.

This paper formulates a methodology to quantitatively assess how the three presented distribution remuneration schemes: cost-of-service, revenue cap, and TOTEX with a fixed capitalization rate, impact the investment decisions of a profit-maximizing DSO. Each remuneration scheme is formulated as a mathematical optimization problem where the decision variables are the network planning solutions that maximize DSO profits subject to technical and economic constraints.

These three formulations are applied to an illustrative case study consisting of a congested substation requiring a combination of planning solutions. OPEX solutions based on flexibility contracts for peak load reductions compete with CAPEX solutions consisting of investment in a new feeder. The results obtained show that the TOTEX with a fixed capitalization rate scheme, despite common belief among regulators, leads to cost misallocation, which, when combined with efficiency incentives, creates distortive investment signals. In contrast, the revenue cap scheme, if designed with a sufficiently high incentive rate, not only fosters efficiency but also mitigates the CAPEX-intensive solutions advantage. Furthermore, once efficiency is properly incentivized, adaptable planning can deliver substantial savings and should be prioritized by regulators, following the shift from cost of service toward revenue cap with profit-sharing schemes.

The main contributions of the paper can be summarized as follows:

- This paper presents three mathematical formulations portraying stylized versions of three DSO remuneration schemes: cost-of-service, revenue cap, and TOTEX with a fixed capitalization rate to evaluate the economic incentives for DSOs planning investment decisions.
- These models allow for quantitatively assessing the effect of an allowed rate of return higher than the DSO´s actual cost of capital (a source of CAPEX bias) and the potential cost savings associated with allowing adaptable planning under each remuneration scheme. These models and potential adaptations may serve as tools helping regulators in establishing priorities for the evolution of remuneration schemes.
- Results obtained in a representative case study show that:
    - The cost-of-service remuneration scheme disincentivizes DSOs from adopting flexibility solutions, hindering potential cost savings for the system.
    - On the other hand, the revenue cap remuneration scheme results in network plans close to minimum system costs with a small bias toward CAPEX grid investment solutions.
    - Despite current overrating by regulators, the TOTEX with a fixed capitalization rate scheme misallocates costs and structurally favors short-term, OPEX-intensive solutions over long-term, CAPEX solutions. This results in inefficient outcomes despite its theoretical appeal.

This paper is organized as follows. Section 2 reviews previous studies on DSO remuneration focused on neutralizing OPEX/CAPEX incentives and adaptable planning. Section 3 presents the methodology of this study, including the mathematical formulation for stylized versions of three remuneration schemes (i.e., cost-of-service, revenue cap, and TOTEX). Section 4 describes the case study to test the proposed methodology. Section 5 presents the results of the case study and discusses some regulatory recommendations arising from these results. Finally, Section 6 summarizes the conclusions of this article and indicates future research lines.

2. State of the art

This section provides the background on two topics that are key for regulating electricity distribution in the current context, characterized by high uncertainty and the increasing availability of smart grid solutions as an alternative or complement to traditional grid investment. First, on establishing neutral OPEX/CAPEX incentives in DSO remuneration schemes, and second, on using adaptable investment strategies for dealing with uncertainty.

Different studies addressing the regulatory challenges for distribution networks have highlighted, among other issues, the need to address these two topics. Pérez-Arriaga et. al. [8] presented a report covering a wide range of topics, including recommended regulatory, policy, and market reforms to address current and future challenges in the power system. Regarding the challenges in the regulation of electricity distribution, it discusses the need to address increasing uncertainty, the need to establish neutral OPEX/CAPEX

incentives, and the need to incentivize innovation, among other topics. Bovera et. al. [9] proposed an approach to regulate electricity distribution that applies a fixed OPEX/CAPEX share (i.e., fixed capitalization rate) and an incentive based on expenditure reduction compared to the expenditure baseline, among other regulatory tools. Bovera et. al. [9] agreed with Pérez-Arriaga et. al. [8] in highlighting the need to address increasing uncertainty and establish neutral OPEX/CAPEX incentives in the regulation of electricity distribution. Anaya and Pollitt [10] presented a study that identifies regulatory changes needed to incentivize the use of flexibility by distribution utilities. The recommendations are based on a questionnaire sent to DSOs, regulators, and experts in the field from seven countries. Regarding DSO remuneration, the study highlights how some jurisdictions like Germany and the Netherlands should improve their remuneration schemes to promote flexibility when cost-efficient. Jenkins and Pérez-Arriaga [11] presented a complete set of recommendations for evolving the remuneration schemes of electricity distribution. The study highlights the need to incentivize efficiency with neutral OPEX/CAPEX incentives, introduce mechanisms to manage uncertainty, and promote long-term innovation along with output-based incentives. Sections 2.1 and 2.2 highlight the need for a quantitative assessment to make regulatory recommendations.

2.1. Establishing neutral OPEX/CAPEX incentives

The CAPEX bias in regulated monopolies has been discussed by researchers and regulatory agencies for several years. The CAPEX bias is the incentive present in remuneration schemes toward CAPEX-intensive solutions rather than OPEX solutions. The increasing relevance of different smart grid solutions in electricity distribution networks, such as the procurement of local flexibility that constitutes mainly an OPEX, has raised the importance of neutralizing incentives between CAPEX and OPEX to achieve overall cost-efficiency and remove barriers to innovative solutions and the evolution of power systems. As described by the Council of European Energy Regulators (CEER) [13], the CAPEX bias has different sources. Next, the hybrid regulatory framework and the CAPEX advantage as sources of CAPEX bias are discussed based on current literature.

The first source of bias emerges when different regulatory approaches are applied to OPEX and CAPEX, commonly referred to as a hybrid regulatory framework. Ex-ante frameworks have been typically applied to OPEX while CAPEX is covered under an ex-post (i.e., cost-of-service) approach [15], and this is still the case nowadays in some countries (e.g., France, Italy, Spain, and Sweden) [17]. This asymmetry creates a bias in favor of CAPEX-intensive solutions, as cost-efficiency incentives apply only to OPEX. Consequently, a DSO is discouraged from pursuing cost-effective OPEX alternatives such as procuring flexibility to defer network reinforcement. The DSO would be penalized in two ways when choosing the OPEX alternative, as reducing CAPEX (i.e., deferring network reinforcement) would decrease the regulated asset base and therefore the returns or profits of the company [8]. Moreover, increasing OPEX (i.e., procuring flexibility) would reduce the company´s returns due to the efficiency incentive applied only to OPEX, even if the overall system cost is reduced.

The second source of bias is the CAPEX-advantage, which has been widely discussed. This effect, first noticed by Averch & Johnson [18], is a result of the difference between the allowed rate of return set by the regulator and the actual cost of capital of the regulated company under cost-of-service regulations. This spread creates an incentive to overinvest. The rate of return is ideally set at a level equal to the company's actual cost of capital, thereby allowing the DSO to attract private investment necessary for financing infrastructure. However, establishing the allowed rate of return equal to the actual cost of capital of the distribution company is difficult for regulators due to information asymmetry and lack of publicly traded unbundled DSOs for comparison, as noted by CEER [13].

The effect of the CAPEX advantage bias is mitigated in ex-ante regulatory approaches compared to cost-of-service approaches, because incentive rate rewards cost-efficiency, while the CAPEX advantage favors CAPEX-intensive solutions. Jamasb [19] pointed out that a sufficiently high rate of return may give an incentive to overinvest that offsets the efficiency incentive set by the incentive rate. This is the case when the profit from a CAPEX solution, due to the spread between the allowed rate of return and the cost of capital, results in higher earnings than the portion of savings that the DSO is allowed to keep as profit with the OPEX solution.

To address the CAPEX advantage that persists even in ex-ante regulatory frameworks, Ofgem introduced the TOTEX (total expenditure) approach [12]. TOTEX is the sum of fast money (expenditures remunerated

in the year they are incurred, similar to OPEX) and slow money (expenditures that are capitalized and remunerated over time through depreciation and a return on capital, as traditionally with CAPEX). The regulator sets a fixed capitalization rate ex-ante for the entire regulatory period. The capitalization rate is the portion of expenditures that is capitalized (i.e., considered slow money), therefore added to the regulated asset base (RAB), regardless of whether they are investments or OPEX. This approach is widely accepted by researchers of the aforementioned studies [8], [9], [10], [11] and regulatory bodies like Ofgem [12], CEER [13] and the Danish utility regulator [14], as a proper way to establish neutral OPEX/CAPEX incentives.

The CAPEX advantage is a result of the asymmetry of information that regulators face when establishing the allowed rate of return for distribution companies, and there is a need to make a quantitative analysis to assess the extent of the CAPEX advantage bias under different regulatory frameworks (Cost-of-service, revenue cap, TOTEX) to enhance the regulatory knowledge on the topic.

Discussions on the topic of neutralizing OPEX/CAPEX incentives tend to be conceptual. Joskow [16] highlights the complicated implementation and evaluation of price caps in the practical setting, and the need to consider the asymmetry of information that regulators face. Regarding the OPEX/CAPEX neutrality issue, considering the information asymmetry, the CAPEX advantage is key. Next, some relevant empirical studies and studies based on models performing quantitative assessments of incentives in regulatory frameworks are detailed, and the gap that this study covers is identified.

Joskow [16] noted that there is little systematic analysis of the effect of different incentive regulation in the distribution network based on empirical evidence (to the best of our knowledge, none of them focused on the OPEX/CAPEX neutrality issue), while there are more of these studies in the telecommunication industry (another regulated sector). An empirical study of the U.S. telecommunication industry [20] found that the price-cap regulation promotes an efficient combination of OPEX and CAPEX. This would suggest that the CAPEX bias due to the CAPEX advantage present in this regulatory environment is negligible.

Regarding quantitative assessments based on models, Vilaplana et al. [21] uses system dynamics to assess investments in the distribution network based on historical data of the Portuguese distribution system, the study suggests that mature digital technologies allowing a more active role of the DSO are properly incentivized when compared to traditional investment under the current regulatory framework in Portugal, which is a revenue cap, benefiting both network users and DSOs. The study suggests that digital technologies that are not mature may be unattractive for DSOs; this may highlight the need to promote innovation. The study does not discuss the OPEX/CAPEX neutrality issue, but it highlights the need to evaluate how changes in the regulatory framework may affect the DSO decisions.

Few studies model a regulatory framework to study the incentives of the DSO. As mentioned before, it is relevant to consider a DSO maximizing profits under a specific regulatory framework to evaluate how incentives may affect DSO investment decisions. Siano [22] modeled optimal wind turbine location from the DSO perspective and the developer perspective. The DSO model includes the consideration of some incentives (i.e., incentive to reduce losses, innovation incentive, and incentive to connect DG). Huang and Söder [23] studied the performance of the different incentives in distribution network investment. The study conducts a quantitative analysis of the impact of the load factor incentive and power loss reduction incentive present in the Swedish regulatory framework. A profit-maximizing DSO operating under a revenue cap regime was considered. To the best of our knowledge, there is no study that quantitatively analyzes the investment decisions of a profit-maximizing DSO under different regulatory approaches (e.g., cost-of-service, revenue cap, TOTEX), nor is there a quantitative study that explicitly examines how the CAPEX advantage affects the DSO decisions across these regulatory frameworks.

In conclusion, there is a lack of quantitative analysis regarding the OPEX/CAPEX neutrality issue, and there is a question to answer in the regulation of electricity distribution: Is there a significant CAPEX bias due to the CAPEX advantage in ex-ante (e.g., revenue-cap) regulatory frameworks? This paper proposes a methodology and a case study to quantitatively address this gap.

2.2. Dealing with uncertainty: adaptable investment strategies

DSOs face important challenges in operation and planning due to the increase in intermittent renewable generation and the penetration of distributed energy resources. Different European countries already

experienced congestions in distribution networks [24], countries like Germany are already noticing this effect and are increasingly facing congestions due to generation peaks in wind farms. At the same time, the Netherlands is also experiencing congestions due to peaks from renewable generation and increasing loads from data centers. Norway is experiencing an increasing penetration of electric vehicles (EVs) and associated congestions due to EV charging. The United Kingdom is facing congestions mainly due to renewable generation and EVs. While congestions in distribution grids in some other countries are not yet a relevant issue, congestions are likely to occur due to the increasing penetration of renewables and distributed energy resources (DERs), compromising the distribution network's hosting capacity and therefore delaying grid connections or limiting the operation of existing resources [25].

However, the uptake pace of new technologies (i.e., penetration of EVs and other DERs) is uncertain, as noticed by network planners like UK National Grid ESO. Their annual report includes projections for peak electricity demand in the United Kingdom up to 2050 [26]. Among the scenarios projected by UK National Grid ESO, there are different paths to achieving net zero objectives and even the possibility of not reaching the net zero targets by 2050. Likewise, Moberg [27] shows how sparse the different forecasts for electricity demand by 2045 in Sweden are, where predictions by various institutions range between a minimum of 16% [28] and a maximum of 125% [29] increase in electricity demand.

Network reinforcements usually occur in discrete steps requiring substantial upfront investments in response to gradual demand growth. This often results in idle grid assets for long periods of time in anticipation of a demand that will eventually increase [30]. In this context, characterized by large uncertainty regarding the penetration of distributed energy resources (DERs) in the coming years, it is important to consider that if the demand growth materializes on the lower end among forecasted scenarios while network plans are prepared for the highest growth conditions this may negatively impact system costs as a large share of assets may remain idle [7], while the lack of investments may delay connections if demand growth materializes on the higher end. This is why the combination of flexibility solutions with adaptable investment strategies is particularly valuable, as they enable DSOs to maintain high service levels, deferring the need to invest in traditional grid reinforcements until the need for reinforcement is confirmed, depending on the actual observed demand growth [31].

Considering flexibility solutions as a temporary alternative to investments in the distribution network is a common practice under some regulatory frameworks, like the UK, while some other countries, like Spain and Italy, are still adapting their regulatory frameworks [17].

Previous research has shown that the cost-saving potential of flexibility services increases when uncertainty is explicitly modeled and adaptable investment strategies are adopted [6]. Unlike traditional investment plans, adaptable strategies based on the real options framework allow investment decisions to be adjusted dynamically based on unfolding information throughout the planning period [5], [6].

To the best of our knowledge, there is no previous study assessing the potential cost savings associated with allowing adaptable investment strategies under different regulatory frameworks (cost-of-service, revenue cap, and TOTEX). This study fills this gap through a methodology and a case study.

3. Methodology

This paper presents a methodology to evaluate the network planning decisions made by a profit-maximizing DSO under a particular remuneration scheme.

The methodology considers a DSO planning tool to solve potential grid problems (e.g., congestions) during a planning horizon of several years in a specific region of the distribution network with either traditional grid reinforcements (e.g., a new feeder or transformer to build), flexibility solutions (e.g., contracting services from flexibility providers that commit to reducing a certain amount of load in a specific timeframe if the DSO sends an activation signal) or a combination of both. Figure 1 presents a summary of the proposed methodology.

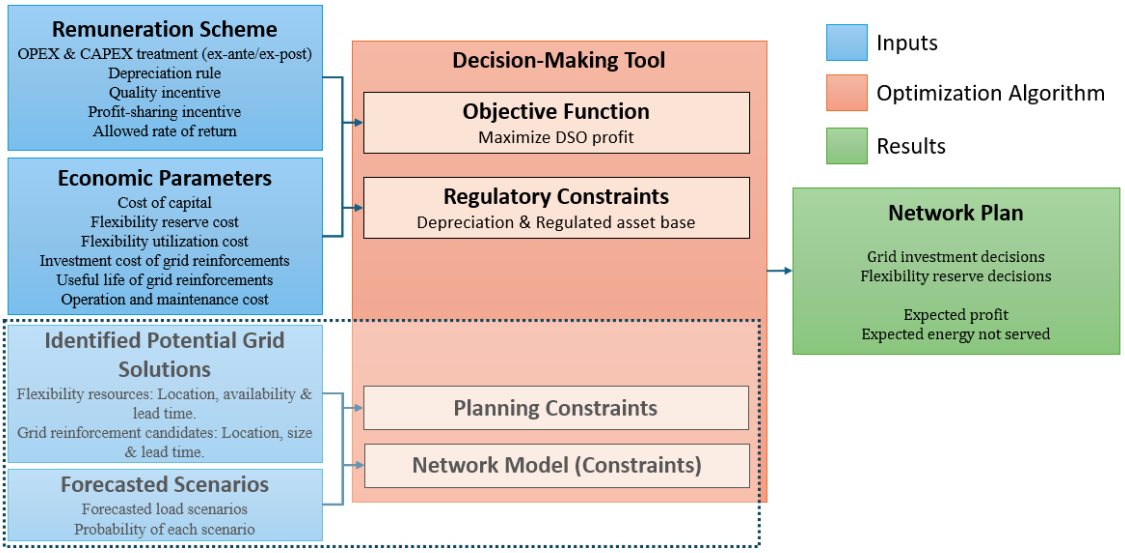

Figure 1. Methodology summary.

The remuneration scheme is an input that defines how the DSO recovers its incurred costs (i.e., through the allowed rate of return, depreciation rules, and the treatment of OPEX and CAPEX with ex-ante or ex-post approaches). The scheme includes various incentives (e.g., quality incentives and profit-sharing mechanisms). These elements are essential for calculating the DSO's profit. Under a well-designed remuneration scheme, the network development plan of a profit-maximizing DSO should ideally align with the minimum-cost network development plan.

The methodology includes different economic parameters as inputs (i.e., cost of capital, flexibility costs, investment cost of grid reinforcements, useful life of grid reinforcements, operation and maintenance costs). These parameters are necessary to calculate the DSO's actual costs under each remuneration scheme based on the planning decisions during the planning period.

The identified potential grid solutions are also an input to the model. These include information on the reinforcement candidates (i.e., a new feeder or transformer) such as the location, size, investment cost, and lead time. The candidate solutions also include flexibility resources with their location, their availability, procurement cost, and lead time. Finally, the forecasted scenarios are also an input for the optimization algorithm; these scenarios show the uncertainty about the evolution of load during the planning period.

The objective function of the decision-making tool maximizes the DSO's profit according to the remuneration scheme considered, which determines the DSO's allowed revenues. This objective function considers how the OPEX and CAPEX are recovered and includes any incentives present in the remuneration scheme (e.g., profit-sharing mechanism, quality incentive, etc.). The calculation includes the incentive that results from the CAPEX-advantage (i.e., the difference between the allowed rate of return set by the regulator and the actual cost of capital of the DSO). If the regulator sets an allowed rate return below the cost of capital of the distribution company, this will discourage investments. This would not be desirable for a critical infrastructure like the distribution network. On the contrary, if the allowed rate of return is set above the cost of capital of the distribution network, it would represent an incentive to over-invest in network assets.

The regulatory constraints calculate different concepts used by regulation to remunerate the DSO (e.g., regulated asset base, depreciation, fast money, slow money, etc.). This calculation derives from the decisions of the DSO during the planning period (e.g., invest in a new feeder or contract flexibility with a provider).

In particular, this study implemented the methodology for three distinct remuneration schemes: the Cost-of-Service (CoS) approach, the revenue cap, and the TOTEX approach. Each scheme is modeled by three different elements: the treatment of OPEX and CAPEX, the quality incentive, and, if applicable, a profit-sharing mechanism. These models are described in Section 3. The objective function and the regulatory constraints for each remuneration scheme are detailed in the problem formulation, see Section 3.2.

The planning constraints capture the scenario and time interdependencies according to the planning approach (single/multi-scenario, single/multi-stage, adaptable or static decisions). For a brief discussion on the different planning approaches, please see [5]. Adaptable planning is an investment plan defined by specific decision rules (i.e., invest in a new transformer whenever the peak load reaches 40MW) that result in investment decisions according to the unfolding information in each scenario during the planning period, so faster load growth scenarios result in earlier investments than the scenarios with slower load growth. In contrast, static decisions are fixed in time (i.e., invest in a new transformer in year 3), resulting in the same decision for all scenarios. Planning constraints consider the lead time of planning actions (e.g., the span of time between the investment decision and the commissioning of the reinforcement) and the irreversibility of reinforcements.

The network model ensures that the physical and operational limits of the power grid are respected and calculates quality of service indicators (e.g., energy not served) based on the adopted grid solution in each unfolding load scenario. The complexity and detail of these constraints may vary, with single-node or multi-node models and capacity limit models, AC power flows, or DC power flows. The methodology in this paper assumes a simple network model (i.e., single node and capacity limit) where a single investment candidate is identified, but the methodology may be extended to consider more complex network models.

Both the planning constraints and the network modeling constraints are shaded and grouped by a dotted line in Figure 1 because they are not the focus of this paper and are not included in this section, but the details of the constraints used for the case study are included in the Annex, explaining their rationale.

The output of the decision-making tool is the network plan, which describes the decisions made by the DSO, such as the expected timing of the planned reinforcements, the expected use of flexibility, and the outputs or performance of this plan, such as the expected profit and the expected energy not served over the years of the planning period.

3.1. Remuneration schemes

This methodology considers three remuneration schemes that are typically present in different countries. The cost-of-service (CoS), the revenue cap, and the TOTEX).

The three models presented here include a quality incentive, as this is a common practice in most remuneration schemes and especially important in a framework that promotes productive efficiency, such as the revenue cap and the TOTEX approaches. Otherwise, cost-efficiency incentives may lead to quality-of-service deterioration.

Next, there is a description of the three approaches considered, and Section 3.2 presents their mathematical formulations.

3.1.1.Cost-of-service

Under the CoS approach, which is an ex-post approach, the distribution company is allowed to recover the costs incurred in carrying out its activities. A rate of return is set by the regulator to ensure the recovery of costs derived from capital expenditures.

The cost-of-service regulatory approach modeled in this methodology applies to both OPEX and CAPEX (i.e., a non-hybrid remuneration scheme). The profit that the DSO would maximize comes from the quality incentive and the difference between the regulated rate of return and the actual cost of capital of the distribution company.

3.1.2.Revenue cap

Under the revenue cap with a profit-sharing mechanism, the allowed revenue for year t, AR_t, is defined as a weighted average between: the value of the revenue trajectory in year t, RT_t, established by the regulator ex-ante, and the DSO actual costs recognized by the regulator ex-post in year t, AC_t, see Equation (1). The weight given to the ex-ante trajectory is the incentive rate, IR.

$$AR_t = IR * RT_t * +(1 - IR) * AC_t = AC_t + IR * (RT_t - AC_t) \quad (1)$$

Figure 2 illustrates the calculation of the incentive from the profit-sharing mechanism under the revenue cap approach. When the DSO's actual costs fall below the ex-ante reference established by the regulator, the DSO is allowed to keep a percentage of this difference; this percentage is known as the incentive rate.

In Figure 2, the incentive resulting from the profit-sharing mechanism is represented by the green-shaded area, which corresponds to 60% (assuming a 60% incentive rate) of the gap between the multi-year revenue trajectory established by the regulator (depicted by the dark blue line) and the DSO's actual costs (represented by the orange line).

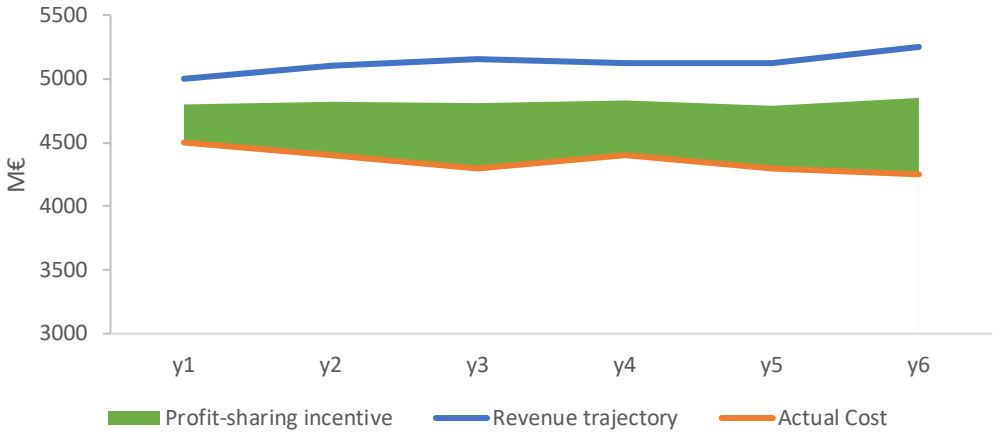

Figure 2. Illustrative example of a profit-sharing mechanism with a 60% incentive rate

The sum of the DSO's actual costs, AC_t, and the incentive from profit-sharing, $IR * (RT_t * AC_t)$, constitutes the allowed revenue, AR_t, as shown in Equation (1). If actual costs exceed the revenue trajectory, the profit-sharing mechanism results in a penalty for the DSO.

3.1.3.TOTEX

The TOTEX approach shares similarities with the revenue cap approach, as both involve the regulator setting a multi-year revenue trajectory complemented by a profit-sharing mechanism. However, a distinctive feature of the TOTEX approach is the application of a fixed capitalization rate to the DSO's expenditures, regardless of whether they are CAPEX or OPEX. This mechanism aims to eliminate the CAPEX-bias, more specifically the CAPEX-advantage, present in traditional remuneration schemes, where DSOs are incentivized to favor capital-intensive solutions over operational alternatives. By this equal treatment of OPEX and CAPEX, the TOTEX approach intends to encourage more economically efficient and unbiased decisions.

Figure 3 illustrates the fixed capitalization effect under the TOTEX approach and how this mechanism affects the actual costs recognized by the regulator. This is not meant to exactly replicate the UK remuneration scheme, just to portray the capitalization effect under the TOTEX approach, on a comparable basis, to extract some conclusions. In the TOTEX approach, a portion of the total expenditure, $totex_t * (CR)$, called slow money, sm_t, is capitalized and goes to the regulated asset base, where the rest, $totex_t * (1 - CR)$, called fast money, fm_t, is directly remunerated. The capitalization rate, CR, is fixed ex-ante by the regulator. Consequently, a DSO using more operational solutions would capitalize expenditures at the same rate as other DSOs that are more focused on capital expenditures.

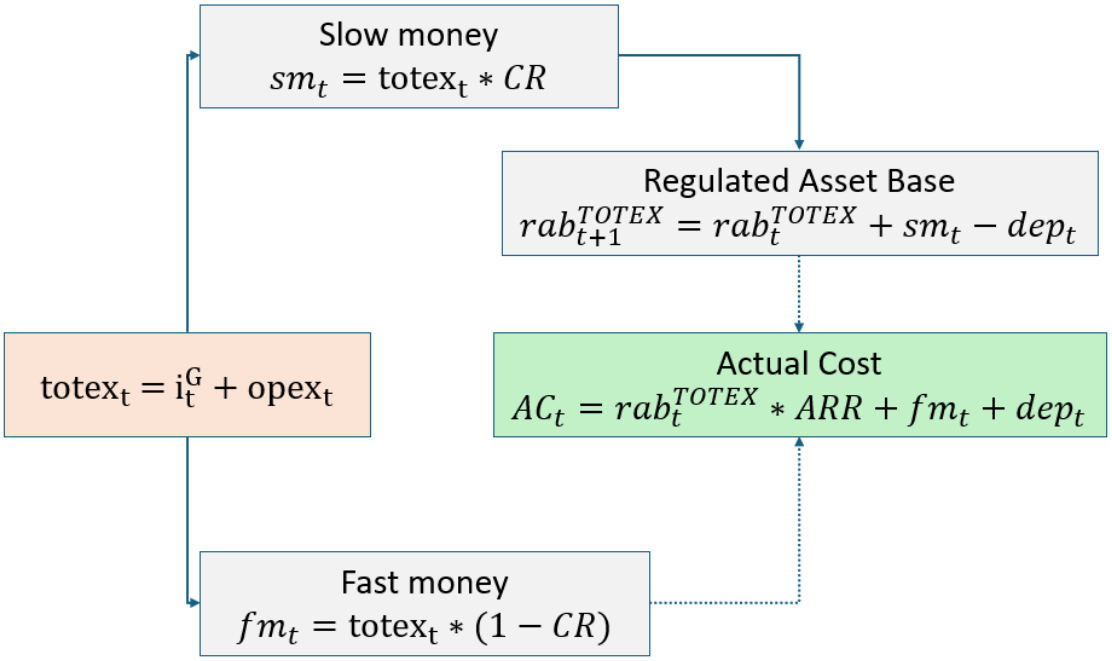

Figure 3. Illustration of the capitalization under the TOTEX approach

The regulated asset base, rab_t^{TOTEX}, is updated according to Equation (2). The slow money, sm_t, is considered as an investment in year t, increasing the value of the asset base, which is updated considering also the depreciation during year t, dep_t, that decreases its value.

$$rab_{t+1}^{TOTEX} = rab_t^{TOTEX} + sm_t - dep_t \quad (2)$$

The actual costs in year t are calculated according to Equation (3), as a sum of the incurred capital costs, $rab_t^{TOTEX} * ARR$, where ARR denotes the allowed rate of return), the fast money, fm_t, as if they were operational expenditures, and the depreciation of the regulated asset base, dep_t.

$$AC_t = rab_t^{TOTEX} * ARR + fm_t + dep_t \quad (3)$$

Then, the incentive resulting from the profit-sharing mechanism is calculated by comparing these actual costs to the ex-ante revenue trajectory set by the regulator, as in the total allowance model, see Equation (1).

3.2. Decision-making tool: mathematical formulation

This section presents the mathematical formulation of the remuneration scheme constraints and the objective function under each considered remuneration scheme.

There are three remuneration schemes considered in this methodology. The formulation for these three schemes is presented assuming:

- A single-node, capacity-limited network model.
- A single reinforcement candidate has already been identified.
- A risk-neutral DSO.
- Uniform average price of flexibility that does not depend on the amount of flexibility reserved or activated.
- A forecast by the DSO including different scenarios for future load conditions growth.

Calculations represent a marginal or incremental analysis to evaluate the consequences of the planning decisions made during the period analyzed. The total revenue and costs of the DSO due to the rest of the assets and operations are not calculated.

Formulation is adopted for a multi-stage, multi-scenario adaptable planning approach.

As already mentioned, the presented formulations can be adapted to consider more complex network models or more candidates for planning solutions.

3.2.1.Planning constraints and network model

The planning constraints control the time interdependencies between the DSO decisions (invest in a grid reinforcement or reserve flexibility) and their availability to solve grid problems (the grid reinforcement entering into service or the flexibility being available for activation). The methodology assumes adaptable planning, where DSO decisions may be different for each scenario.

The network model transforms the planning decisions into estimations of the grid operational conditions. This methodology estimates the energy not served as a quality-of-service metric and calculates an incentive associated with this metric.

The details of the planning constraints and the network model used for the case study are included in the Annex, explaining their rationale.

3.2.2.Variables

This optimization model involves different variables depending on the selected remuneration scheme. Table 1 shows the variables used by the model under each remuneration scheme.

Table 1. variables of the optimization model depending on the selected remuneration scheme.

Variable	CoS	Revenue cap	TOTEX
$dep_{s,t}$	✓	✓	
$dep_{s,t}^{TOTEX}$			✓
$ens_{s,t}$	✓	✓	✓
$f_{s,t}^{res}$	✓	✓	✓
$f_{s,t}^{act}$	✓	✓	✓
$fm_{s,t}$			✓
$g_{s,t}$	✓	✓	
$i_{s,a}$	✓	✓	✓
$om_{s,t}$	✓	✓	✓
$rab_{s,t}$	✓	✓	
$rab_{s,t}^{TOTEX}$			✓
$sm_{s,t}$			✓
$totex_{s,t}$			✓

As it was explained in Section 3.1.3, fixing the capitalization rate in the TOTEX approach changes the way that the value of the regulated asset base is updated (through slow money instead of investments). This is why the TOTEX approach present different variables for the RAB, $rab_{s,t}^{TOTEX}$, and the depreciation, $dep_{s,t}^{TOTEX}$, and some additional variables for calculations such as the total expenditure, $totex_{s,t}$, the slow money, $sm_{s,t}$, and the fast money, $fm_{s,t}$.

3.2.3.Cost-of-Service formulation

Under the CoS approach, the DSO is allowed to recover the incurred cost of the activity. A rate of return is set to recover capital expenditure. This rate of return is set at an attractive level, so the company is able to attract private funds to finance its activity. This approach also considers a quality incentive.

Objective function

Equation (4) shows the objective function of a DSO maximizing the profit under the CoS approach.

$$\max_{ens_{s,t},rab_{s,t}} C = \sum_{t,s} \frac{1}{(1+CC)^t} * Pr_s * \left(rab_{s,t} * (ARR - CC) + \left(ENS_t^{ref} - ens_{s,t}\right) * VoLL\right) \quad \forall s,t > FLT \tag{4}$$

The profit considers two items:

- *Profit from the asset base remuneration:* Under the Cost-of-Service (CoS) approach, the regulated firm is guaranteed recovery of its costs, and therefore, incurred costs do not appear in the objective

function as they do not affect the company's profit. However, the regulator must determine an allowed rate of return (ARR) on capital investments. As mentioned in section 1, this ARR may differ from the firm's actual Cost of Capital (CC), potentially resulting in either a profit or a loss over the minimum required return for the DSO. This profit or loss is captured in the term $rab_{s,t} * (ARR - CC)$, where $rab_{s,t}$ denotes the Regulated Asset Base at scenario s and year t, which reflects the net asset value of the investments during the planning period. If ARR equals CC, the firm earns just enough to maintain investor interest. If ARR exceeds CC, the firm gains a surplus return. Conversely, if ARR is below $WACC$, investment becomes unattractive, potentially leading to underinvestment.

- *Profit from the quality incentive:* Most remuneration schemes include an incentive to reduce service interruptions. The regulator establishes a reference for quality of service (typically based on historic data and regulator objectives), and overperformers/underperformers receive a reward/penalty. This is modeled as $\left(ENS_t^{ref} - ens_{s,t}\right) * VoLL$, where ENS_t^{ref} represents the reference for energy not served (MWh) established by the regulator for year t, $ens_{s,t}$ represents the energy not served (MWh) in scenario s and year t. $VoLL$ is the value of lost load (€/MWh) established by the regulator used for the incentive calculation.

Each scenario is weighted in the objective function according to its associated probability, Pr_s. This allows the DSO to assign higher probability to the more plausible scenarios and lower probability to less likely ones. Since this analysis considers the DSO perspective, the cost of capital (CC) is applied to bring all the considered costs to the present.

As current decisions only impact future years due to lead time constraints, the early years of the planning horizon cannot be influenced by DSO decisions during the planning period. As a result, these initial stages are treated as sunk costs and are excluded from the model cost calculations. The lead time for flexibility is typically shorter than the lead time for grid reinforcement. Therefore, the objective function only considers years where $t > FLT$, as no intervention can influence earlier stages.

Constraints

Depreciation calculation: The depreciation is assumed to be linear over the asset's useful life. Equation (5) models the annual depreciation for each scenario s and year t. Depreciation is calculated as the ratio of the investment in grid reinforcement, G^{inv}, to the asset's useful life, G^{ul}. This only applies in scenarios and years where the reinforcement is in operation, $g_{s,t} = 1$. Otherwise, there is no depreciation.

$$dep_{s,t} = g_{s,t} * \frac{G^{inv}}{G^{ul}} \quad \forall s,t \tag{5}$$

This constraint ensures that depreciation is accounted only after the asset enters in service and continues annually over its useful life.

Regulated asset base calculation: Equation (6) defines how the RAB is updated each year. The RAB in year $t+1$ is calculated as the RAB in year t adding the expenditure related to the investment that entered into service sometime during year t, represented by $i_{s,t}^G * G^{inv}$, minus the depreciation of the investment that were included in the RAB in year t, represented by $dep_{s,t}$. This affects all the scenarios separately so that the formulation is compatible with adaptable decision-making. Constraint (7) ensures that the value of the regulated asset base in year 0 is 0 for all the scenarios, so that the value of the RAB is only affected by the investment decisions during the planning period. Previous investments are considered sunk costs, unaffected by decisions made during the analyzed period, and are therefore excluded from the scope of this analysis.

$$rab_{s,t+1} = rab_{s,t} - dep_{s,t} + i_{s,t}^G * G^{inv} \qquad \forall s, t < T \tag{6}$$

$$rab_{s,t} = 0 \qquad \forall s, t = 1 \tag{7}$$

3.2.4.Revenue cap formulation

Under the revenue cap, the regulator defines an ex-ante multi-year revenue trajectory for the regulatory period. The DSO allowed revenue results in a weighted average between the DSO's actual cost and the ex-ante revenue trajectory. This approach also considers a quality incentive.

Objective function

Equation (8) shows the objective function of a DSO maximizing the profit under a revenue cap approach.

$$\max_{rab_{s,t}\ dep_{s,t}\ f_{s,t}^{res}\ f_{s,t}^{act}\ om_{s,t}\ ens_{s,t}} C = \sum_{t,s} \frac{1}{(1+CC)^t} * Pr_s * \big(rab_{s,t} * (ARR - CC) + IR * RT_t - IR(rab_{s,t} * ARR + dep_{s,t} + f_{s,t}^{res} * FR^{Cost} + f_{s,t}^{act} * FU^{Cost} + g_{s,t} * OM^{cost}) + (ENS_t^{ref} - ens_{s,t}) * VoLL\big) \quad \forall s,t \tag{8}$$

The profit considers three items:

- *Profit from the asset base remuneration:* This formulation is equivalent to the profit from immobilized capital already presented in the cost-of-service approach. This is modeled as $rab_{s,t} * (ARR - CC)$.
- *Profit-sharing mechanism:* The profit-sharing mechanism, as explained in Section 3, is an incentive based on the difference between the revenue trajectory and the actual cost incurred by the DSO. The actual costs (incurred cost recognized by the regulator) considered in each scenario s and year t include:
  - Cost of capital, $rab_{s,t} * ARR$.
  - Depreciation cost, $dep_{s,t}$.
  - Flexibility reserve cost, $f_{s,t}^{res} * FR^{Cost}$.
  - Flexibility activation cost, $f_{s,t}^{act} * FU^{Cost}$.
  - Operation and maintenance costs, $g_{s,t} * OM^{cost}$.

  The incentive resulting from profit-sharing (PSI) is given by Equation (9), consistent with Equation (1).

$$PSI_{s,t} = IR * RT_t - IR(rab_{s,t} * ARR + dep_{s,t} + f_{s,t}^{res} * FR^{Cost} + f_{s,t}^{act} * FU^{Cost} + g_{s,t} * OM^{cost}) \tag{9}$$

- *Profit from quality incentives:* This formulation is equivalent to the profit from the quality incentive already presented in the cost-of-service approach. This is modeled as $\left(ENS_t^{ref} - ens_{s,t}\right) * VoLL$.

As explained for the cost-of-service approach, the present value of the profit obtained in each year is calculated using the cost of capital, CC, as the discount rate. Each scenario is weighted in the objective function according to its associated probability, Pr_s. The objective function only considers years where $t > FLT$, as no intervention can influence earlier stages.

Constraints

Depreciation calculation: Under the revenue cap approach, depreciation is calculated the same way as in the CoS approach, please see Equation (5) already explained.

Regulated asset base calculation: Under the revenue cap approach, capitalization is conducted the same way as in the CoS approach, please see Equations (6) and (7) already explained.

3.2.5.TOTEX formulation

Under the TOTEX approach, similar to the revenue cap approach, the regulator defines an ex-ante revenue trajectory, RT_t^{TOTEX}, and a profit-sharing mechanism applies. However, under the TOTEX approach, a portion of the actual DSO expenditures, regardless of whether they are OPEX or CAPEX, is capitalized and goes to the regulated asset base. This portion is known as slow money, $sm_{s,t}$. The rest of the DSO´s expenditures are considered fast money, $fm_{s,t}$. They are not capitalized and treated as yearly costs.

Objective function

Equation (10) shows the objective function of a DSO maximizing the profit under a TOTEX approach.

$$\max_{i^1,tr^G,f^1,tr^F} C = \sum_{t,s} \frac{1}{(1+CC)^t} * Pr_s * \left[rab_{s,t}^{TOTEX} * (ARR - CC) + IR * RT_t^{TOTEX} - IR(rab_{s,t}^{TOTEX} * ARR + dep_{s,t}^{TOTEX} + fm_{s,t}) + (ENS_t^{ref} - ens_{s,t}) * VoLL\right] \quad \forall s,t > FLT \tag{10}$$

The equation considers three items for profit calculation:

- *Profit from the asset base remuneration*: Similar to the CoS and revenue cap approaches, this is modeled as $rab_{s,t}^{TOTEX} * (ARR - CC)$.
- *Profit-sharing mechanism*: As described in Figure 3, the actual costs (recognized by the regulator) considered in each scenario s and year t include:
  - Cost of capital, $rab_{s,t}^{TOTEX} * ARR$.
  - Depreciation cost, $dep_{s,t}^{TOTEX}$.
  - Fast money, $fm_{s,t}$.

  The incentive resulting from the profit-sharing mechanism, $PSI_{s,t}$, is given by the Equation (11), consistent with Equation (1), and considering the calculation of actual costs under the TOTEX approach illustrated in Figure 3:

$$PSI_{s,t} = IR * RT_t^{TOTEX} - IR(rab_{s,t}^{TOTEX} * ARR + dep_{s,t}^{TOTEX} + fm_{s,t}) \tag{11}$$

- *Profit from quality incentives:* As in the CoS and revenue cap approaches, this is modeled as $\left(ENS_t^{ref} - ens_{s,t}\right) * VoLL$.

Constraints

TOTEX calculation: Equation (12) calculates the DSO´s total expenditure in scenario s and year t, $totex_{s,t}$, as the sum of the investment that entered into service during year t in scenario s, $G^{inv} * i_{s,t}^G$, and the operational expenditures for year t and scenario s, such as the cost of reserving flexibility, $f_{s,t}^{res} * FR^{Cost}$, the cost of flexibility activation, $f_{s,t}^{act} * FU^{Cost}$, and the operation and maintenance cost, $om_{s,t}$.

$$totex_{s,t} = G^{inv} * i_{s,t}^G + f_{s,t}^{res} * FR^{Cost} + f_{s,t}^{act} * FU^{Cost} + om_{s,t} \quad \forall s,t \tag{12}$$

Fast money calculation: Equation (13) calculates the fast money in scenario s and year t ($fm_{s,t}$) as the portion of the total expenditure ($totex_{s,t}$) that is not capitalized, according to the fixed capitalization rate (CR).

$$fm_{s,t} = totex_{s,t} * (1 - CR) \quad \forall s,t \tag{13}$$

Slow money constraints: Equation (14) calculates the slow money in scenario s and year t ($sm_{s,t}$) as the portion of the total expenditure ($totex_{s,t}$) that is capitalized, according to the fixed capitalization rate (CR).

$$sm_{s,t} = totex_{s,t} * (CR) \quad \forall s,t \tag{14}$$

Depreciation calculation (TOTEX): Equation (15) calculates the annual depreciation of the regulated asset base according to the TOTEX approach, using the useful life fixed by the regulator (R^{ul}). All the slow money expenditures made prior to year t are depreciated during year t. Since the useful life considered (usually 40 years) is greater than the planning period (usually 5-10 years), there is no need to check if the slow money is fully depreciated in this analysis. Equation (16) ensures there is no depreciation in year 1.

$$dep_{s,t}^{TOTEX} = \sum_{a=1}^{a=t-1} sm_{s,a}/R^{ul} \quad \forall s,t > 1 \tag{15}$$

$$dep_{s,t}^{TOTEX} = 0 \quad \forall s,t = 1 \tag{16}$$

Regulated asset base calculation (TOTEX): Equation (17) defines how the RAB is updated each year under the TOTEX approach. The RAB in year $t+1$ is calculated as the RAB in year t adding the expenditure related to the slow money in year t considered under the TOTEX capitalization rules, represented by $sm_{s,t}$, minus the depreciation in year t, represented by $dep_{s,t}^{TOTEX}$. This affects all the scenarios separately so that formulation is compatible with adaptable decision-making. Constraint (18) ensures that the value of the regulated asset base in year 0 is 0 for all the scenarios, as in the CoS and the revenue cap approaches.

Investments made prior to the considered planning period are treated as sunk costs, and are therefore excluded from the scope of this analysis.

$$rab_{s,t+1}^{TOTEX} = rab_{s,t}^{TOTEX} - dep_{s,t}^{TOTEX} + sm_{s,t} \qquad \forall s, t > 1 \tag{17}$$

$$rab_{s,t}^{TOTEX} = 0 \qquad \forall s, t = 1 \tag{18}$$

4. Case study

This section presents a case study to illustrate the application of the proposed methodology. The case study consists of a substation in a distribution network that is expected to be congested. This substation has a capacity limit of 60 MW. There are two possible interventions to solve the substation congestion.

- First, reinforce the grid by building a new feeder that redirects part of the load (a maximum of 20MW) to an adjacent substation. The new feeder entails an investment of 432 k€, with a useful life of 40 years, and its lead time for commissioning is three years[3].
- Second, contract flexibility from connected users. There are 4MW of available flexibility for peak reduction each year of the planning period. The cost for reserving flexibility is 33.35 €/MW/h, and the cost for flexibility activation is 200.68 €/MWh based on [33][4]. The lead time considered for flexibility is one year.

The allowed rate of return established by the regulator is 5.58%[5] which in the first analysis is considered equal to the cost of capital of the regulated company, and the value of lost load (VoLL) is 4500 $/MWh.

4.1. Scenarios for peak load evolution

The scenarios for peak load evolution are taken from [5], which are adapted from the "Future Energy scenarios 2023" elaborated by National Grid in the UK [26].

Table 2. Peak load scenarios (MW)

	Year										
	0	1	2	3	4	5	6	7	8	9	10
b1	57,7	56,8	57,2	58,1	58,9	60,4	62,9	65,9	68,5	71,5	75,2
b2	57,7	58,0	58,2	58,4	58,9	59,6	60,6	62,1	63,3	64,9	66,8
b3	57,7	56,2	54,9	55,0	55,9	57,0	59,0	60,7	62,8	66,3	69,7
b4	57,7	61,0	61,8	62,8	63,5	64,4	65,1	66,1	67,4	69,0	70,8

These four base scenarios represent the long-term uncertainty. Then, [5] performed a Monte Carlo simulation to add noise to these scenarios, representing the short-term uncertainties. The increase or decrease in the materialized noise is modeled as a normal distribution with a mean of 0 and a standard deviation of 0.4%. The simulation generated a total of 160 scenarios, 40 per base scenario. The dataset is included in the supplementary material.

4.2. Load duration curve

Figure 4 represents the form of the load duration curve for the substation under study in year 0 with a peak load of 57.7 MW. An assumption is that this load duration curve will maintain its form with all hourly values growing at the same rate as the peak load. The load duration curve is taken from [5], which is based on data for 2019 from the Spanish Transmission System Operator database [35]. The resulting LDC used in this case study is available in the supplementary material.

[3] The International Energy Agency indicates in [32] that the lead time for investments in the distribution network in Europe varies between 2 and 4 years.

[4] Average availability and utilization payments from February 2021 tender based on the report by Aurora Energy Research [33]. Conversion rate considered 1.15 Euro/GBP.

[5] 5.58% is the WACC established by the Spanish regulator CNMC [34].

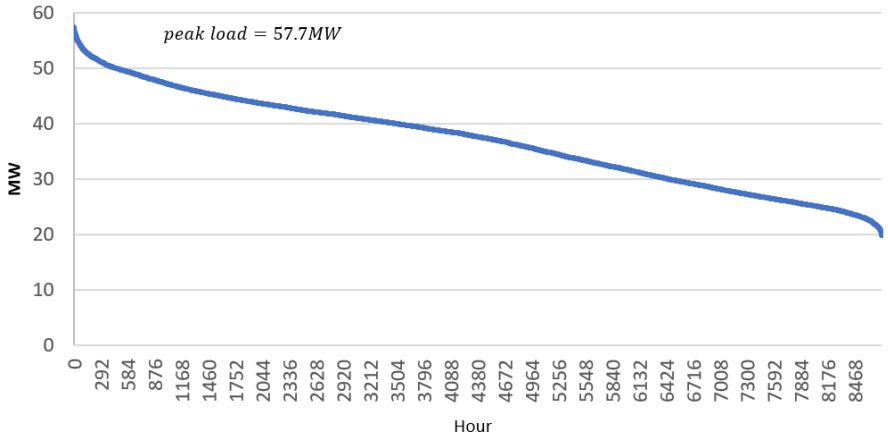

Figure 4. Load duration curve at year 0 used for the case study.

4.3. Details on considered remuneration schemes

First, the ex-post (cost-of-service) approach is considered. This traditional method involves the recovery of the incurred costs. Next, the ex-ante (revenue cap) approach with a 50% profit-sharing mechanism is examined. The DSO shares 50% of any profits or losses relative to this cap. For this approach, the ex-ante revenue trajectory is determined by the cost of the network plan under the cost-of-service approach. This decision is motivated by the regulatory logic underlying both frameworks. Under cost-of-service regulation, the DSO is remunerated based on the incurred costs, subject to regulatory approval of the investment plans. In contrast, the revenue cap framework establishes an ex-ante trajectory of allowed revenues, which implicitly reflects the regulator's assessment of what constitutes reasonable and efficient costs. Using the incurred costs under the cost-of-service ensures comparability of results across the two remuneration schemes. Similarly, the reference for the quality of service (defined as ENS_t^{ref} in the methodology) is the expected energy not served under the cost-of-service scheme.

Finally, the TOTEX approach incorporates a fixed capitalization rate of 80% to total expenditures (both capital and operational), alongside a 50% profit-sharing mechanism. The revenue trajectory under the TOTEX approach is derived from the network planning decisions made under cost-of-service, with cost components recalculated according to the TOTEX capitalization rules. As for the revenue cap approach, the reference for the quality-of-service incentive in the TOTEX approach is the expected energy not served under the cost-of-service scheme.

5. Results & discussion

This section presents the results of the case study, focusing on the DSO's planning decisions over a 10-year period under the three selected remuneration schemes.

Table 3 presents the results of the case study considering traditional planning with fixed static planning decisions at each year of the planning period. The grey-shaded column in Table 3 presents the decisions made under a cost-minimizing strategy obtained with an optimization model where the objective function is cost minimization rather than the DSO´s profit maximization. A key objective for any remuneration scheme is to incentivize DSOs to achieve the minimum system cost (MSC) solution. However, this outcome is not always attainable. Consequently, the MSC solution serves as a benchmark for evaluating the performance of a particular remuneration scheme in guiding the DSO's planning decisions. Table 3 also includes the expected flexibility activation (MWh), the expected energy not served (MWh), and the expected cost of the network plan (€)[6], for each remuneration scheme and for the minimum cost solution.

[6] The expected cost of the network plan includes the expected flexibility cost (reserve and activation), the expected cost related to investments (cost of capital and depreciation of the grid asset), the expected cost of energy not served valued at 4,500 €/MWh, and the expected operation and maintenance cost of the grid asset. The discount rate, to calculate the present value of these costs, is the Allowed rate of return established by the regulator (5.58% in this assumption).

Table 3. DSO decisions under the different remuneration schemes with traditional planning

	MSC	Cost-of-Service	Revenue cap	TOTEX
Investment	1 Feeder	1 Feeder	1 Feeder	1 Feeder
% of scenarios with reinforcement	100%	100%	100%	100%
Expected year of grid investment	3	1	3	3
Expected Flexibility Reserve (MW_h)	759	155	759	759
Expected Flexibility Activation (MWh)	75	16	75	75
Expected ENS	2.61	0.75	2.61	2.61
Expected cost of the network plan	165,290 €	191,056 €	165,290 €	165,290 €

Table 3 shows that the cost-of-service leads to the highest cost network plan (191,056 €), 15.6% higher than the cost of the MSC network plan. The expected year for the grid investment decision is year 1 (the first year of the planning period), so there is no utilization of flexibility to delay network reinforcement under the cost-of-service remuneration scheme. In contrast, the revenue cap and the TOTEX approaches lead to the exact same network plan that coincides with the minimum cost network plan.

Table 4 presents the DSO investment decisions for the case study, considering adaptable planning, see Annex. Under the cost-of-service, results show little difference compared to the traditional planning approach, with a slight decrease in the expected cost (1.5%), and again, no use of flexibility to delay grid reinforcement (the expected year for the investment decision is year 1). The MSC and the TOTEX yield nearly identical solutions with a 12% decrease in expected cost compared to traditional planning. The network plan under the revenue cap shows a 5% lower use of flexibility (57.5 MWh of expected flexibility activation) compared to MSC (60.6 MWh of expected flexibility activation), although this difference does not significantly impact the expected cost of the network plan. These results suggest that there is a CAPEX-bias present in the revenue cap approach, 57.5 MWh of flexibility activation under revenue cap vs 60.6 MWh and 59.2 MWh of flexibility activation under MSC and TOTEX, respectively. This bias manifests when there is little cost difference between the CAPEX and the OPEX solutions. This is why the impact on the expected cost is almost negligible, with a 0.8% increase compared to MSC (145,904 € vs 144,731 €). The bias can also be noticed in the expected year of the grid investment, presenting a small reduction in the revenue cap approach (2.98 years) compared to MSC (3.06 years). The expected year of grid investment has decimal numbers, because with adaptable planning, the investment decision in each scenario may be different according to unfolding information; a higher demand growth will result in an earlier investment decision and vice versa. Thus, the decimal number represents the expected year of grid investment across the 160 scenarios, considering adaptable planning.

Table 4. DSO decisions under the different remuneration schemes with adaptable planning

	MSC	Cost-of-Service	Revenue cap	TOTEX
Investment	1 Feeder	1 Feeder	1 Feeder	1 Feeder
% of scenarios with reinforcement	100%	100%	100%	100%
Expected year of grid investment	3.06	1.00	3.04	3.06
Expected Flexibility Reserve (MW_h)	270	68	266	271
Expected Flexibility Activation (MWh)	61	16	59	61
Expected ENS (MWh)	1.41	0.63	1.38	1.40
Expected cost of the network plan (€)	144,731 €	188,161 €	144,739 €	144,750 €

These results show that allowing adaptable planning may have little to no cost-reduction effect under cost-of-service approaches, while it may have a significant impact under revenue cap and TOTEX approaches (reducing costs by 12%).

Table 5 presents the expected present value of incurred costs by the DSO and the incentives considering adaptable planning; these are economic figures corresponding to the case presented in Table 4. The incurred cost related to capital expenditures includes the depreciation and the cost of capital for the investment in the feeder.

As expected, the cost-of-service approach presents the highest incurred cost (CAPEX related), because there is no deferral of the grid reinforcement, while the revenue cap approach and the MSC present a similar cost in this category, which was expected as the year for grid investment is very similar in Table 4.

The TOTEX approach, however, presents an artificially low number in this category, because the capitalization rate is fixed and thus the value of the regulated asset base differs from the value of the actual asset base. With the fixed capitalization rate of 80%, 20% of the CAPEX (i.e., 20% of the investment in the feeder) is considered fast money and not capitalized, increasing "OPEX" and decreasing the regulated asset base and thus decreasing the cost of "CAPEX". This is the reason why we see a lower value in CAPEX-related cost and a higher value in OPEX, when the network plan was almost identical to MSC, as shown in Table 4.

Table 5. Expected present value of the main economic figures under each remuneration scheme with adaptable planning

	MSC	Cost-of-Service	Revenue Cap	TOTEX
Incurred Cost (OPEX)	29,941 €	25,573 €	29,737 €	72,001 €
Incurred Cost (CAPEX related)	109,865 €	160,130 €	110,151 €	93,745 €
Total Incurred Costs (a)	139,806 €	185,703 €	139,888 €	165,746 €
Quality incentive (b)	-	0 €	-2,393 €	-2,456 €
Incentive from profit-sharing (c)	-	-	22,908 €	23,159 €
Total allowed revenue (a + b + c)	-	185,703 €	160,403 €	186,449 €
DSO Profit (b + c)	-	0 €	20,515 €	20,703 €
Residual RAB*	378,941 €	356,714 €	378,805 €	334,346 €
Productive inefficiency	-	43,430 €	8 €	19 €
Allocative inefficiency	-	-	20,515 €	20,703 €

*The residual RAB represents the value of the regulatory asset base at the end of the planning period

Table 5 shows further consequences of the fixed capitalization rate in the TOTEX approach, not only inflating the OPEX figure and decreasing the CAPEX figure. The impact is also reflected in the residual RAB (i.e., the net value of the regulated asset base at the end of the planning period): 334,346 € under the TOTEX approach, compared to 378,941 € for the MSC case and 378,805 € for the revenue cap framework. This variation occurs despite the expected year of grid investment being similar across the two approaches (revenue cap and TOTEX) and the MSC benchmark, as shown in Table 4. Looking at the total allowed revenue, which represents the amount of money that network users would pay through tariffs. Although they would pay more during the regulatory period (the 10 years studied) under the TOTEX approach (with total allowed revenue of 186,449 € versus 160,403 € under the revenue cap), future payments under TOTEX would be lower due to the smaller residual RAB (334,346 € vs 378,805 €). In conclusion, the fixed capitalization rate in this case temporarily increased payments of connected users while decreasing future payment obligations through a lower RAB.

For a fair comparison of the DSO's planning decisions across the different remuneration schemes, the selected metric is the expected cost of the network plan, presented in Table 4. As previously discussed, this

metric eliminates the distortion created by the fixed capitalization rate in the incurred costs, thus resulting in similar values across the MSC, the revenue cap, and the TOTEX, along with a similar expected timing of investment decisions.

When examining the cost-efficiency of a distribution company, we may distinguish between productive efficiency (i.e., minimizing cost), which is maximized if the network plan equals the minimum cost network plan, and allocative efficiency (i.e., minimizing rent extraction by the regulated company), which is maximized when the allowed revenue for the distribution company is exactly their actual cost.

In the cost-of-service approach, the distribution company is remunerated equal to its actual cost. Thus, there is no allocative inefficiency. In contrast, the expected cost of the network plan is 188,161 € vs 144,731 € of the minimum-cost network plan. This results in 43,430 € of productive inefficiency, as shown in Table 5.

In the case of the revenue cap and the TOTEX approach, the allocative inefficiency is related to the incentives given to guide the DSO decisions (i.e., profit-sharing and quality incentives in this case), which account for 20,515 € and 20,703 €. In contrast, there is little productive inefficiency, 8 € and 19 €, representing less than 0.02% of the total cost.

The results reveal similar total inefficiency (combining productive and allocative inefficiency) for both the revenue cap and TOTEX approaches, each around 21 k€. In contrast, the cost-of-service approach exhibits significantly higher total inefficiency, more than double at 43,430 €.

5.1. Sensitivity Analysis

DSOs may encounter different volumes of flexibility available at different costs depending on several factors, such as the availability of flexible resources at a given location, the network topology, and the regulatory conditions, among other factors. Therefore, it is valuable to test whether the case study results remain consistent under different values of flexibility cost and availability.

Sensitivity analysis on flexibility cost and flexibility availability

The case study initially considered 4MW of available flexibility; in this sensitivity analysis, this figure varies from 1MW (25% of the initial value) to 8MW (two times the initial value). Similarly, the cost of flexibility varies from 8.34 €/MW/h reserve cost and 50.17 €/MWh activation cost (25% of the initial value) up to 100.05 €/MW/h reserve cost and 625.08 €/MWh activation cost (three times the initial value considered in the case study).

Figure 5 presents the sensitivity analysis for the difference in the use of flexibility (i.e., MWh of activated flexibility) between the network plan under the TOTEX approach and the MSC network plan. Figure 6 compares the expected present cost of the network plan under the TOTEX approach with the expected present cost of the MSC network plan (both Figure 5 and Figure 6 considered adaptable planning).

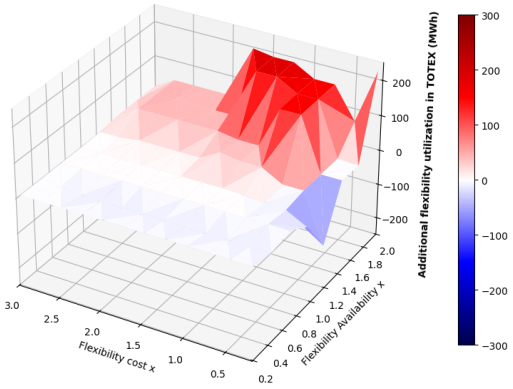

Figure 5. Sensitivity Analysis of the Increase in Expected Flexibility Activation: TOTEX vs. MSC under Varying Flexibility Cost and Availability

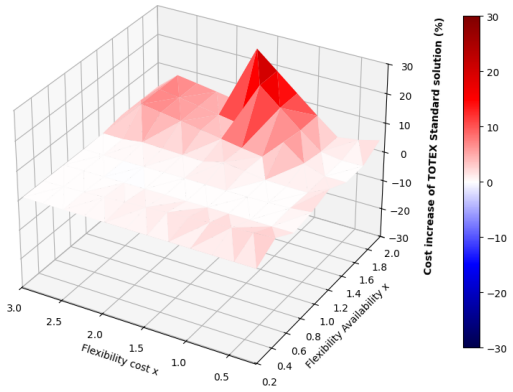

Figure 6. Sensitivity Analysis of the Percentage Increase in Expected Present Cost: TOTEX vs. MSC under Varying Flexibility Cost and Availability

While the initial results of the case study in Table 4 showed that both the TOTEX and the MSC resulted in similar flexibility activation, Figure 5 shows that this does not hold true across different contour conditions. The TOTEX approach presents an excess of flexibility use, marked by a red colored area in Figure 5. This happens in cases where available flexibility is high (over 5MW, 1.25x initial estimation), and the effect is accentuated at medium and low flexibility prices. When available flexibility is low, there is a lower use of flexibility (blue colored area) under the TOTEX approach. Overall, in the TOTEX approach, the flexibility activation increases by 38.2% compared to the MSC benchmark.

Figure 6 shows that there is some correlation between the excess use of flexibility and an increase in the expected cost. The highest increase in expected cost (up to 24% increase compared to MSC) appears in cases where there is high availability of flexibility, at a medium-high price (i.e., between 0.75 and 2 times the initial cost of flexibility). These results suggest there is an OPEX bias, related to the higher use of flexibility, in the TOTEX approach. Overall, the TOTEX approach presents a 2.3% increase in cost compared to MSC. The cause of this OPEX bias is analyzed in Section 5.2.

Figure 7 presents the sensitivity analysis for the difference in flexibility use (i.e., MWh of activated flexibility) between the network plan under the revenue cap scheme and the MSC network plan. Figure 8 compares the expected present cost of the network plan under the revenue cap approach with the expected present cost of the MSC network plan (both Figure 7 and Figure 8 consider adaptable planning).

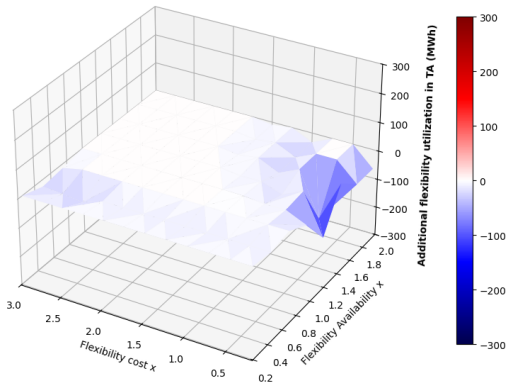

Figure 7. Sensitivity Analysis of the Increase in Expected Flexibility Use: revenue cap vs. MSC under Varying Flexibility Cost and Availability

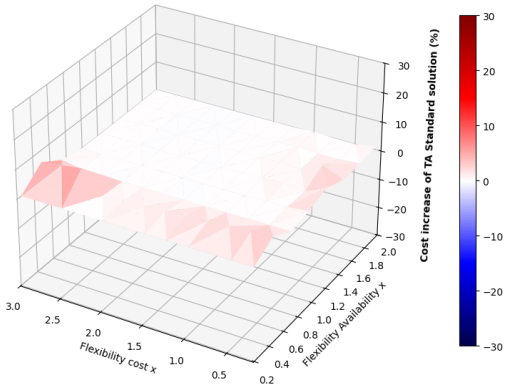

Figure 8. Sensitivity Analysis of the Percentage Increase in Expected Present Cost: revenue cap vs. MSC under Varying Flexibility Cost and Availability

Figure 7 shows a decrease in expected flexibility use for the network plan under the revenue cap approach compared to the MSC approach, overall, 12.7% less use of flexibility. This effect is accentuated when there is medium-high availability of flexibility at a low price.

Figure 8 shows that the impact of the difference in flexibility use on the expected cost is minor, with an overall 0.6% increase in expected cost. This means that there is a CAPEX bias in the revenue cap approach for the tested conditions. The consequences of this bias primarily arise in cases where the expected cost between the OPEX and CAPEX solutions is similar, thus resulting in limited impact on overall cost-efficiency. Thus, we preliminarily conclude that the impact of the CAPEX-bias on overall planning efficiency under the revenue cap approach is limited. Next, we extend the analysis to examine how the CAPEX-advantage, defined as the difference between the allowed rate of return and the DSO's actual cost of capital, may influence this conclusion.

Sensitivity analysis on the cost of capital and the incentive rate

As explained in Section 2, an allowed rate of return higher than the actual cost of capital of the distribution company is a source of CAPEX-bias (i.e., the CAPEX-advantage) that the TOTEX approach is designed to mitigate. The presented case study considered a 5.58% allowed rate of return equal to the actual cost of capital of the distribution company. In order to consider the effect of the CAPEX-advantage, a sensitivity analysis is conducted assuming 5.58%, 4.58% and 3.58% as the actual cost of capital of the distribution company while maintaining 5.58% as the allowed rate of return. Since, as discussed in Section 2, the CAPEX-advantage may counter the effect of the profit-sharing mechanism, the sensitivity analysis includes variations in the incentive rate, considering 30% and 70% in addition to the 50% initially considered. The

analysis also considers variations in flexibility costs and availability, as shown in the previous sensitivity analysis in Figures 5 to 8.

Table 6 shows the results of the sensitivity analysis. Each of the cells represents the overall percentage increase in expected cost and activated flexibility under a specific value of the cost of capital of the distribution company and a specific value for the incentive rate. The results presented in the previous analysis, with a 50% incentive rate and a cost of capital of 5.58%, Figures 5 to 8 showed a 0.6% increase in expected cost for the revenue cap approach, along with an 12.7% decrease in flexibility use. While the TOTEX approach presented a 2.3% expected cost increase and a 38.2% increase in flexibility use. These are the numbers that Table 6 summarizes under an incentive rate equal to 50% and a cost of capital equal to 5.58%.

Table 6. Sensitivity analysis of expected cost and expected flexibility use compared to MSC benchmark. Variations in incentive rate (IR) and cost of capital (CC).

		Revenue Cap			TOTEX		
		IR=30%	**IR=50%**	**IR=70%**	**IR=30%**	**IR=50%**	**IR=70%**
Cost of capital =5.58%	Cost Increase in the network plan	2.1%	0.6%	0.1%	2.5%	2.3%	3.1%
	Flexibility use Increase	-22.6%	-12.7%	-5%	4.3%	38.2%	57.2%
Cost of capital =4.58%	Cost Increase in the network plan	3.8%	1.9%	0.4%	2.6%	2.5%	1.9%
	Flexibility use Increase	-39.9%	-25.1%	-13.1%	-22.8%	10.95%	36,6%
Cost of capital =3.58%	Cost Increase in the network plan	13.6%	3.7%	1.6%	5.5%	2.1%	1,3%
	Flexibility use Increase	-67.7%	-38.3%	-25.4%	-42.2%	-12%	17%

Table 6 shows that increasing the incentive rate under the revenue cap approach reduces the cost of the network plan, decreasing the difference with the benchmark (MSC approach), with only a 0.1% difference in the case of a 70% incentive rate and a 5.58% cost of capital. As expected, increasing the incentive rate increases productive efficiency, while increasing the use of flexibility to a level closer to the MSC network plan. At the same time, a lower cost of capital increases the CAPEX advantage, leading to more inefficient solutions and lower flexibility use, as expected when this source of CAPEX-bias increases.

The effect of this sensitivity analysis on the network plan under the TOTEX approach is not so straightforward. The base case, with a 50% incentive rate and a cost of capital of 5.58%, showed an increase in cost of 2.3% compared to the MSC network plan (this is the result from the sensitivity analysis presented in Figure 6). One may think that increasing the incentive rate up to 70% would lead to a more efficient network plan; however, it leads to a 3.1% difference in cost compared to MSC. While the excess use of flexibility goes from 38.2% to 57.2%. Therefore, a higher incentive rate amplified the OPEX-bias already present in the base case (Figure 5 and Figure 6), resulting in a less efficient solution.

A clear and consistent effect in the results of the TOTEX approach is that increasing the incentive rate increases the use of flexibility. While this may lead to more efficient or more inefficient solutions. This shows again that the TOTEX approach presents an OPEX bias, and this is aggravated when the incentive rate increases. Similarly, a larger spread between the ARR and the CC leads to lower use of OPEX solutions (flexibility in this case). But the effect on overall efficiency is mixed, as a higher spread may lead to more efficient or less efficient solutions.

Next, we discuss the regulatory implications deriving from these results.

5.2. Discussion and regulatory implications

As discussed in the introduction, dealing with uncertainty and neutralizing incentives between OPEX-intensive and CAPEX-intensive solutions are key regulatory challenges for distribution networks in the upcoming years.

Establishing neutral incentives in DSO remuneration schemes is key to promoting smart grid flexibility solutions, as there is a bias toward CAPEX solutions present in traditional regulation. Next, we discuss the different nature of OPEX and CAPEX and, in light of the case study results, whether equal treatment of CAPEX and OPEX is a desirable feature in DSO remuneration schemes.

Does equal OPEX/CAPEX treatment lead to neutral incentives? The nature of OPEX and CAPEX

Under traditional capitalization approaches, investments are treated as capital expenditure (CAPEX) and are not accounted for as immediate costs. Instead, their value is depreciated over time across the asset's useful life, with an additional cost component reflecting the allowed return on assets during the same period. This cost-accounting method spreads the financial impact of the investment over its operational lifespan. In contrast, treating a capital investment as an immediate cost would unfairly penalize it in cost-efficiency comparisons, especially for grid assets with long lifespans (e.g., 40 years), since the full cost would be assigned in the first year while the asset would be in service for a long time. On the other hand, an operational expenditure (OPEX) is a recurring cost to maintain business operations (maintenance, labor, etc.). These operational expenditures are traditionally treated as costs. Capitalizing them would result in a cost misallocation by spreading the cost of a short-term solution over many years.

To illustrate this concept, please consider a simplified case involving a five-year planning horizon. Suppose that the DSO must choose between a one-time 100 k€ investment with a 40-year useful life and an operational alternative costing 20 k€ per year. If the CAPEX is not capitalized, both options would appear to cost 100k€ over the five years, disregarding the time value of money. However, this comparison is misleading: the investment alternative will continue to deliver value for 35 more years, while the operational solution would not address any grid issues beyond the five-year period. Thus, failing to capitalize the investment would distort the analysis and bias decisions toward the short-term OPEX alternative.

Now consider the impact of applying a fixed capitalization rate to the same simple case, as fixing the capitalization rate is proposed by the previously analyzed TOTEX approach, as a measure to neutralize OPEX/CAPEX incentives. Under an 80% capitalization rate, both the investment and operational alternatives would have the same "fast money" cost (i.e., 20 k€) and a total addition to the RAB of 80 k€ during the five years. However, the operational solution provides no long-term benefit, and it is not a cost-efficient solution. In contrast, under traditional capitalization, considering a 5.58% rate of return, a 40-year useful life of the asset, and constant annuity payments accounting for depreciation and cost of capital, the cost of the investment alternative would be 6.48 k€/year, resulting in significant savings over the operational alternative (20 k€/year).

This leads to a critical issue: capitalizing OPEX causes a misallocation of costs. By spreading the cost of a short-term solution over many years (some potentially falling outside the regulatory period), the actual cost incurred during the relevant regulatory period is then understated. When combined with cost-efficiency incentives such as profit-sharing, this understatement of the OPEX would result in rewarding non-existing efficiency, introducing a new bias, this time favoring OPEX over CAPEX. Therefore, while the intention of capitalizing OPEX is to neutralize CAPEX/OPEX incentives, it may in fact create a different distortion in the form of an OPEX bias. This bias was observed in the case study results (Figure 5 and Figure 6). In conclusion, CAPEX and OPEX differ in nature, and equal treatment does not lead to neutral incentives. Therefore, capitalizing OPEX should not be the preferred method to achieve incentive neutrality between OPEX and CAPEX solutions.

Table 6 shows that the results under the revenue cap approach are easier to interpret. For example, a regulator may increase the incentive rate in a given regulatory period if the objective is to enhance productive efficiency. Conversely, a low use of flexibility in the network plans may indicate a significant spread between the allowed rate of return (ARR) and the distribution company's actual cost of capital (CC). In contrast, the mixed effects inherent to the TOTEX approach not only create distortions in efficiency incentives by artificially favoring OPEX solutions but also complicate the analysis and potential future regulatory adjustments. Moreover, the case study results do not show an overall efficiency improvement under the TOTEX compared with the revenue cap, further questioning its suitability. In addition, the implementation of the revenue cap is straightforward in comparison to the more complicated TOTEX with

a fixed capitalization rate implementation. Since simplicity is a guiding principle of regulation, the use of the revenue cap is recommended over the TOTEX approach.

This study does not analyze the effects of multiple regulatory periods on DSO incentives. However, as highlighted in [13], CAPEX-based solutions provide long-term stability of returns (CAPEX stability bias) for the regulated firm over the asset's lifespan (typically around 40 years), spanning several regulatory periods. Assessing how investment decisions made in one period shape the allowed revenues in subsequent periods, potentially introducing a structural bias toward CAPEX solutions, should be analyzed considering the adjustments that regulators introduce at the beginning of each regulatory period. This analysis exceeds the scope of this paper and could be the aim of future research. In any case, addressing this long-term bias should not come at the cost of creating short-term distortions, such as those previously commented on, generated by fixing a capitalization rate for the total expenditure.

Priorities in remuneration schemes emerging from this study

Results showed that both the revenue cap and the TOTEX approaches significantly benefit from adaptable planning, improving productive efficiency under both remuneration schemes. On the other hand, there is little to no benefit in mandating adaptable planning under the cost-of-service approach. In addition, note that enabling multi-scenario adaptable planning could incentivize DSOs to include extreme or high-cost scenarios in their investment plans to justify elevated expenditures, particularly at the start of the regulatory period when they present plans to the regulator, who sets the allowed revenue baseline. Therefore, regulators should exercise caution when permitting multi-scenario planning approaches, especially if allowed revenue baselines are predominantly based on DSO-submitted investment plans, rather than on benchmarking methods or externally derived parameters.

After the presented findings, the following regulatory recommendations emerge. First, regulators should prioritize transitioning away from cost-of-service remuneration schemes or hybrid approaches toward an ex-ante revenue cap with a profit-sharing mechanism. This shift enables more effective use of flexibility solutions while promoting cost-efficiency. Second, once efficiency is properly incentivized, enabling adaptable planning has the potential to bring additional efficiencies. Third, regulators may want to achieve OPEX/CAPEX neutral incentives, but thinking of implementing a TOTEX scheme with a fixed capitalization rate is not a recommended option. Regulators may achieve better outcomes by refining the revenue cap with profit-sharing schemes, rather than adopting a fixed-capitalization rate or other similar schemes that result in capitalizing OPEX.

Long-term regulatory effectiveness requires acknowledging the asymmetry of information between DSOs and regulators. Allocative inefficiencies resulting from cost-efficiency incentive mechanisms should not be viewed as a regulatory failure but as a necessary cost for revealing firms' efficiency potential. This allocative inefficiency can be addressed by adjusting the revenue baseline of future periods in light of previously achieved efficiencies. Hence, the goal should not be to eliminate inefficiency entirely, but to manage and learn from it in order to progressively improve the regulation.

5.3. Limitations of the study and future research

This study does not assess two sources of CAPEX bias described in [13], which are the CAPEX stability and the OPEX risk. These sources of CAPEX bias are less discussed in the literature and are outside of the scope of this paper. However, they represent potential research lines in the future, especially, as discussed in the previous section, the CAPEX stability that provides long-term incentives for CAPEX solutions.

This study considers a single regulatory period, so it does not assess how the rules for setting the allowed revenue baseline in the following periods may create incentives to alter investment decisions in the current regulatory period. As mentioned, this is a relevant topic for further research that falls outside the scope of this study.

In terms of quality of service, the presented methodology focuses on the estimation of the energy not served as an indicator; future research may consider other metrics if deemed necessary, such as energy losses, number and frequency of supply interruptions, etc.

Finally, the planning methodology presented in the Annex considers only a single reinforcement candidate, whereas a DSO may need to evaluate multiple reinforcement options simultaneously. Moreover, the

planning model assumes a single-node capacity-limited network element, which, in our case study, is the net load supplied by a substation. Considering a multi-node network with power flow calculations and voltage operational constraints would enable the simultaneous analysis of multiple congested elements and the assessment of different remedial actions, including flexibility solutions allocated across various nodes of the system.

6. Conclusions

This study assessed the planning investment decisions of a profit-maximizing distribution system operator (DSO) under three different remuneration schemes: cost-of-service, revenue cap, and TOTEX, considering both traditional and adaptable planning models. The findings provide clear insights into the strengths and limitations of each scheme in guiding cost-efficient planning solutions, combining grid investment and smart grid flexibility.

The results show that the cost-of-service approach leads to the least efficient outcomes, with investment decisions significantly deviating from the minimum system cost (MSC) benchmark. The cost-of-service approach fails to incentivize cost minimization, showing high productive inefficiency and no use of flexibility solutions to delay network reinforcement. Additionally, adaptable planning under this approach yields similar results as traditional planning with negligible cost reduction, highlighting again the limited use of flexibility solutions due to the absence of efficiency incentives. These results show that a CAPEX bias is present to a large extent under cost-of-service remuneration schemes.

In contrast, both the revenue cap and TOTEX approaches achieve network plans that resulted in close to the MSC benchmark. Allowing adaptable planning brings significant benefits in productive efficiency under both remuneration schemes.

The TOTEX approach, while promising in theory and against the generalized belief of regulators, presents an OPEX bias. The fixed capitalization rate in the TOTEX misallocates capital and operational costs, artificially favoring OPEX-intensive flexibility solutions over CAPEX-intensive grid investment.

The revenue cap approach strikes a better balance. This approach presents a CAPEX bias due to the CAPEX advantage. The CAPEX advantage is accentuated as the allowed rate of return set by the regulator exceeds the actual DSO cost of capital by greater margins. However, in the analyzed case study, the effect of this CAPEX bias on overall efficiency is limited. Sensitivity analysis shows that regulators can mitigate this bias by increasing the incentive rate.

The effects of the different decisions made by the regulators are easier to interpret under the revenue cap scheme compared to the TOTEX approach, making it easier for regulators to analyze the DSO results observed in past regulatory periods and make adjustments for the next one, resulting in a practical regulatory choice.

Regulators should prioritize transitioning away from cost-of-service remuneration schemes or hybrid approaches toward ex-ante revenue cap approaches with a profit-sharing mechanism. This shift enables more effective use of flexibility solutions while promoting cost-efficiency. Then, once efficiency is incentivized by the proper remuneration scheme, enabling adaptable planning has the potential to bring additional efficiencies. Third, regulators may want to achieve OPEX/CAPEX neutral incentives by implementing TOTEX with a capitalization rate, but following the obtained results, this practice is not recommended.

Annex

The network model and planning constraints used in this study are derived from a previous study [5]. The considered network model is a single-node capacity-limited substation. The methodology may be extended to consider more complex network models (e.g., multi-node network models including thermal and voltage operational limits). The planning constraints considered correspond to adaptable planning based on a real options approach. Next, we present the formulation of these constraints for the purpose of replicability of the presented results. For a detailed explanation and discussion on the planning approach details and its implications, please refer to [5].

Notation

In addition to the sets, parameters, and variables already defined for the main text, there are some additional variables for the formulations included in this Annex:

Parameters:

ENS_t^{ref}: reference for energy not served set by the regulator for the quality incentive (€).

$ENS_{s,t}^0$: energy not served without any intervention to solve grid problems at scenario s and year t (MWh).

$ENS_{s,t}^F$: energy not served if flexibility is reserved at scenario s and year t (MWh).

$ENS_{s,t}^G$: energy not served if grid is reinforced at scenario s and year t (MWh).

FLT: lead time for flexibility. (years).

GLT: lead time for grid reinforcement. (years).

M: a large numerical value with the purpose of relaxing the constraint.

$P_{s,t}$: actual peak load in scenario s and year t (MW).

ϵ: a small numerical value with the purpose of avoiding strict inequalities when formulating constraints.

Variables:

$\delta_{s,t}$: 1 if no intervention is made, 0 if either grid is reinforced or flexibility is reserved for scenario s and year t.

f^1: 1 if flexibility is reserved at year 1 for all scenarios s, 0 otherwise.

i^1: 1 if decided to invest in grid reinforcement at year 1 for all scenarios s,0 otherwise.

$r_{s,t}^F$: 1 if flexibility is reserved for scenario s and year t, 0 otherwise.

tr^F: trigger level for reserving flexibility (MW).

tr^G: trigger level for investment in grid reinforcement (MW).

$tr_{s,t}^{G-act}$: 1 if peak load in scenario s' and year (t-1) reaches or surpasses the grid reinforcement trigger; 0 otherwise.

Planning constraints

Grid reinforcement constraints

The decision to reinforce the grid follows a trigger-based rule, where the trigger level, tr^G determines whether grid reinforcement is required in future periods (t>1).

Constraint (19) ensures that the trigger for grid reinforcement is activated when the previous year's peak load exceeds the trigger level.

Constraint (19) ensures that no grid trigger activation occurs if the previous year's peak load remains below the trigger level, tr^G.

$$tr_{s,t}^{G-act} * (M + \epsilon) - \epsilon \geq P_{s,t-1} - tr^G \quad \forall s, 2 \leq t \leq T - GLT \tag{19}$$

$$\left(1 - tr_{s,t}^{G-act}\right) * (M + \epsilon) - \epsilon \geq t_r{}^G - P_{s,t-1} \quad \forall s, 2 \leq t \leq T - GLT \tag{20}$$

The trigger level functions as a rule for future decisions (t>1). Additionally, any investment decision after $T - GLT$ would result in grid reinforcement being commissioned beyond the last year of the planning period T. Therefore, there is no trigger activation beyond $T - GLT$ or in t=1 considered in this analysis. Constraint (21) enforces this logic.

$$tr_{s,t}^{G-act} = 0 \quad \forall s, t > (T - GLT) \cup \mathrm{t} = 1 \tag{21}$$

The grid reinforcement is modeled as a one-time commitment, allowed at most once per scenario during the planning period. This restriction is enforced by constraint (22).

$$\sum_t i_{s,t}^G \leq 1 \quad \forall s \tag{22}$$

Constraint (23) guarantees that if grid reinforcement is made in year 1, the decision is binding for every scenario.

$$i^{G}_{s,t=1} = i^{1} \quad \forall s \tag{23}$$

Constraint (24) requires that grid reinforcement decisions (for t > 1) can only occur following trigger activation.

$$i^{G}_{s,t} \leq tr^{G-act}_{s,t} \quad \forall s, t \geq 2 \tag{24}$$

Constraint (25) ensures that the grid investment is made in at the first grid trigger activation.

$$\sum_{t=1}^{a} i^{G}_{s,t} \geq tr^{G-act}_{s,t=a} \quad \forall s, a \tag{25}$$

Constraint (26) ensures that no trigger activation occurs during year 1.

$$tr^{G-act}_{s,t=1} = 0 \quad \forall s \tag{26}$$

Constraint (27) enforces the lead time between the reinforcement decision and commissioning, and ensures that once the asset enters service in a given scenario, it remains operational throughout the planning horizon.

$$g_{s,t=a+GLT} = \sum_{t=1}^{a} i^{G}_{s,t} \quad \forall s, a \leq T - GLT \tag{27}$$

Constraint (33) ensures that grid reinforcement cannot become operational before year GLT+1, since the earliest decision to reinforce can only be made at t=1.

$$g_{s,t} = 0 \quad \forall s, t \leq GLT \tag{28}$$

Flexibility reserve constraints

The decision to reserve flexibility also follows a trigger-based rule, where the trigger level, tr^{F} determines whether flexibility reserve is required in future periods (t>1).

Constraint (29) ensures that flexibility is only reserved when the previous year's peak load exceeds the trigger level and no grid reinforcement is scheduled for commissioning in year t + FLT.

Constraint (30) ensures that no flexibility is reserved if the previous year's peak load remains below the trigger level, tr^{F}.

$$\left(r^{F}_{s,t} + g_{s,t+FLT}\right) * (M + \epsilon) - \epsilon \geq P_{s,t-1} - tr^{F} \quad \forall s, 2 \leq t \leq T - FLT \tag{29}$$

$$(1 - r^{F}_{s,t}) * (M + \epsilon) - \epsilon \geq tr^{F} - P_{s,t-1} \quad \forall s, 2 \leq t \leq T - FLT \tag{30}$$

Constraint (31) enforces that the decision to reserve flexibility in year 1, denoted as f^{1}, must apply uniformly across all scenarios.

$$r^{F}_{s,t=1} = f^{1} \quad \forall s \tag{31}$$

Constraint (37) ensures that no flexibility is reserved after year T − FLT, as doing so would lead to activation beyond the planning horizon.

$$r^{F}_{s,t} = 0 \quad \forall s, t > T - FLT \tag{32}$$

Constraint (33) ensures that flexibility is not reserved in year t if grid reinforcement is already scheduled for commissioning in year t + FLT. This is based on the assumption that the reinforcement fully resolves future network congestion.

$$r^{F}_{s,t} \leq 1 - g_{s,t+FLT} \quad \forall s, 1 \leq t \leq T - FLT \tag{33}$$

Network model

Calculation of the energy not served

The rule for determining the flexibility to reserve in each scenario and year is based on the real options framework and the latest available information. At the start of year t, the methodology calculates the flexibility to be reserved for activation in year t + FLT, using base scenario forecasts and the observed peak load evolution from year 0 to t − 1. Figure 9 illustrates this decision-making process for scenario s.

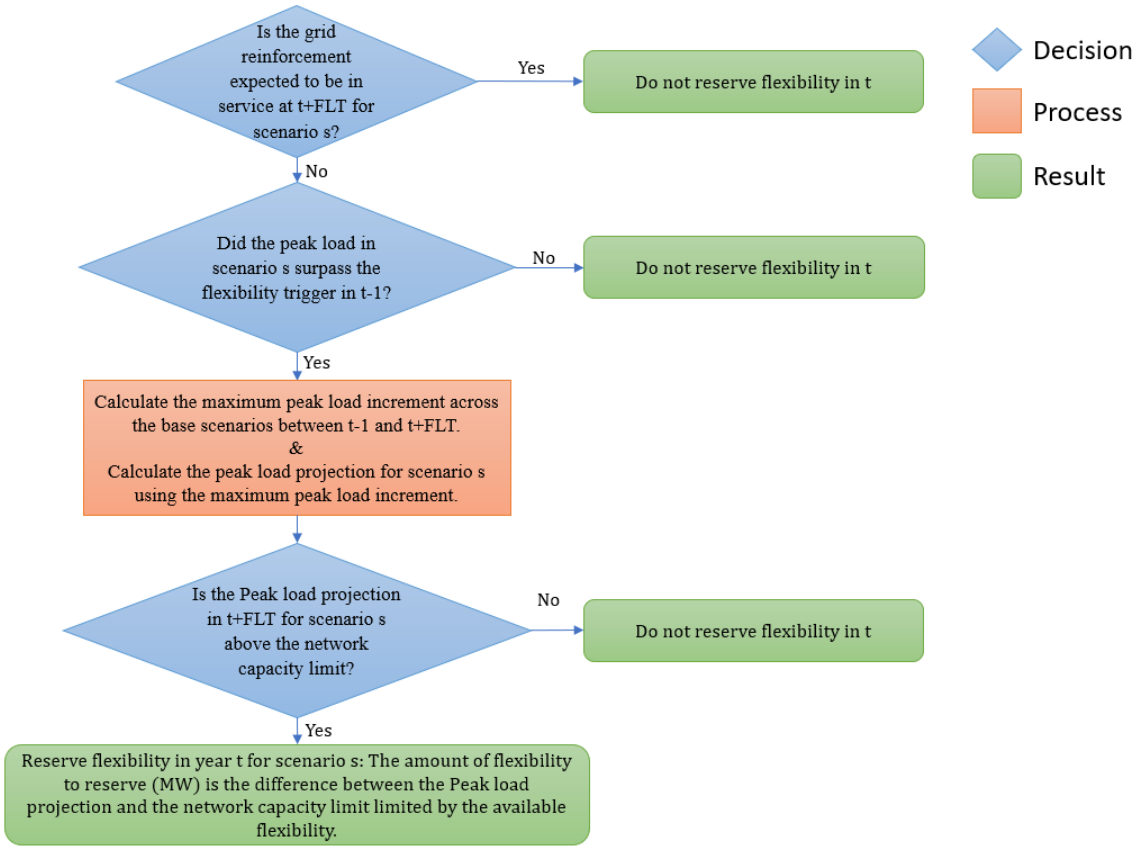

Figure 9. Decision-making process to reserve flexibility using the real options approach

Calculation of the energy not served

Figure 10 shows how energy not served (ENS, yellow area) is calculated for scenario s and year t when flexibility is reserved but no grid reinforcement is in place. Flexibility, activated during peak hours (green area), temporarily increases network capacity.

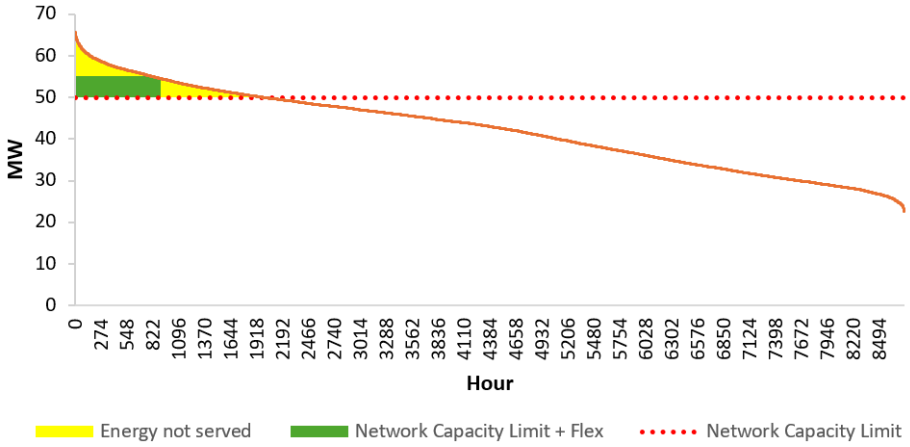

Figure 10. Illustration of the network capacity limit, the load duration curve, and the amount of energy not served if flexibility is reserved.

Flexibility activation and energy not served constraints

Constraint (34) ensures that the energy not served in each scenario and year reflects the type of intervention applied. This is $ENS^{0}_{s,t}$ if no action is taken, $ENS^{F}_{s,t}$ if flexibility is reserved, $ENS^{G}_{s,t}$ if grid reinforcement is commissioned.

Constraint (35) ensures that variable δ takes a value of 1 when no intervention is made at each year t and scenario s.

$$ens_{s,t} \geq ENS^{0}_{s,t} * \delta_{s,t} + ENS^{F}_{s,t} * r^{F}_{s,t-FLT} + ENS^{G}_{s,t} * g_{s,t} \quad \forall s, t \geq 1 + FLT \tag{34}$$

$$r^{F}_{s,t-FLT} + g_{s,t} \geq 1 - \delta_{s,t} \quad \forall s, t \geq 1 + FLT \tag{35}$$

Considering more complex network models (e.g., multi-node network models and including voltage operational limits) would require additional constraints, such as enforcing power flow equations between nodes and enforcing the desired technical performance metrics. The model may also be extended to consider additional reinforcement and flexibility solutions as alternatives by adding more variables that represent the different possible interventions.

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Miguel A. Ruiz: Conceptualization, Methodology, Software, Validation, Formal analysis, Writing - Original Draft, Visualization. **Tomás Gómez**: Conceptualization, Writing - Review & Editing, Supervision, Visualization. **José P. Chaves**: Conceptualization, Writing - Review & Editing, Supervision, Visualization.

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Declaration of generative AI and AI-assisted technologies in the writing process

During the preparation of this work, the author(s) used ChatGPT to improve the manuscript's readability and language. After using this tool, the author(s) reviewed and edited the content as needed and take(s) full responsibility for the content of the published article.

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