Bremen Energy Working Papers

JACOBS UNIVERSITY

Paperseries No. 33

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March 2020

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Suggested citing:
Gert Brunekreeft, Julia Kusznir, Roland Meyer, Madoka Sawabe and Toru Hattori (2020). Incentive regulation of electricity networks under large penetration of distributed energy resources – selected issues, *Bremen Energy Working Papers* No. 33, Jacobs University Bremen.

Incentive regulation of electricity networks under large penetration of distributed energy resources – selected issues

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March 27, 2020

Abstract: The rapid growth of Distributed Energy Resources (DER) and their integration into network presents currently the greatest challenges for many network operators worldwide in terms of network stability and power quality. To meet these challenges not only huge investment in grid expansion and smart grid technologies is required, but also the network regulation needs to adapt from cost efficiency towards investment and innovation. We analyze the recent experiences with the regulatory framework in several countries facing significant challenges of large penetration of DER. We discuss several selected regulatory issues that are important for promoting needed investment while ensuring cost efficiency, such as the length of regulatory period, X-factor, and allowed rate of return. We conclude that in the era of smart grids, incentive regulation requires a long-term perspective and needs to address the regulatory risks and uncertainties related to investment into grid expansion and smart grid technologies. To do so, incentive regulation should be supplemented by more innovative, investment-friendly regulatory measures. Additional supplementary mechanisms such as output-based regulation would be useful to achieve the regulatory goals and develop fully functional and consumer-oriented smart grid, though details for their implementation still have to be worked out.

1 Introduction

Currently, the electricity network operators in Europe are facing their possibly greatest challenges in terms of network stability and power quality due to the rapid increase of renewable energy penetration and distributed energy resources (DER) that need to be integrated into the distribution networks. The undergoing changes in the power system with growing shares of DER require huge investment not only in network capacity expansion but also innovative information and communication technologies in order to create scalable and flexible smart grids in the economically most efficient way.

Since the electricity network sector is regulated by the state institutions, the regulatory framework is important to cope with these challenges. In this regard, incentive regulation, which was successfully implemented in many European countries since the recent liberalization wave of the European electricity market, plays an important role. In general, incentive regulation provides network operators with strong incentives for cost efficiency; whether it promotes investment in the network infrastructure without immediate cost reduction is, however, controversial. It seems that no satisfactory regulatory framework for achieving the goals related to the development of smart grids has been established so far.

Although cost efficiency continues to be an important objective of network regulation, increasing investment needs in the network expansion has called for a reform or redesign of incentive regulation in European countries, including the UK and Germany (cf. Brunekreeft & Meyer, 2016). For example, incentive regulation in the UK was modified such that the assessment of allowed revenues for the investments needed for a low carbon, sustainable electricity network is based on outputs: the keyword is "value-for-money" for consumers. Germany has also gained experience in incentive regulation for cost efficiency for a decade, but recently the framework for setting allowed revenue was changed to promote investments for the integration of increasing amounts of DER into the grid.

In Japan, the government established cost-of-service regulation for network operators in the course of restructuring of the electricity sector in the 1990s. Foreseeing increasing costs of network expansion and large investment needs to integrate rapidly growing amounts of DER into the grid and aiming to improve grid reliability and resilience (including recovery from natural disasters), the government intends to replace the cost-of-service regulation with incentive regulation in the form of revenue cap regulation. In the discussion for designing revenue cap regulation, the government refers to the regulatory practices in Germany and the UK to see how the required investments could be promoted more efficiently and effectively, as these countries have experienced similar issues.

In this paper we analyze the recent experiences with incentive regulation in Germany, the UK, and the US. Then we evaluate the impacts of the regulatory tools on efficiency promotion and network investment. These tools include 1) the length of regulatory period, 2) efficiency and productivity requirement (X-factor), 3) allowed rate of return (WACC) as well as 4) treatment of capital and operating expenses (CAPEX and OPEX). Subsequently, we explore the potential for "output-based regulation" and examine whether this new regulatory framework can strengthen incentives for value creation of network operators and provide the companies with greater operating flexibility needed for successful implementation of decarbonization strategies. The paper is organized as follows: Section 2 gives an overview of the economic features of investment requirement into the electricity grid in the future and discusses a need for revision of incentive regulation as widely adopted in Europe. Subsequently, recent developments of network regulation in Germany and the UK in terms of increasing investment needs are summarized, followed by a review on the current discussion on the implementation of the incentive regulation in Japan. Section 3 discusses the impact of the duration of the regulatory period on investment and efficiency as well as regulatory cost. Section 4 reviews the impact of efficiency and productivity requirement as reflected in so-called X-factor. Section 5 analyzes the impact of the allowed rate of return on grid investment, given the scale and risks of needed investment. Section 6 examines the different regulatory treatment of OPEX and CAPEX. Section 7 deliberates on the potential of output-based regulation. Section 8 concludes our discussion.

2 Economic features of future investment requirements for electricity networks

In this section we first review the discussion on the challenges of electricity network regulation in Europe as growing amounts of DER are to be connected to the distribution grid.

2.1 Need for reforming incentive regulation in Europe

In the course of restructuring and liberalization of the European electricity market more than a decade ago, many European countries, including Germany and the UK, adopted incentive regulation to control the overall price level of grid operators (TSOs and DSOs). One of the widely used approaches is revenue cap regulation (CEER, 2019). It is well known that revenue cap regulation in general provides strong incentives for cost reduction for the regulated operator. One of the critical issues, however, is how to provide incentives for cost-increasing investment needed, for instance, to enhance reliability. In many cases, a so-called quality factor was included in the revenue cap formula in order to incentivize the maintenance or improvement of quality of supply as measured by the frequency or duration of outages.

The investment requirements for the integration of large amounts of DER into the grids are expected to be huge. British energy regulator Ofgem estimated in 2010 that the network investment required in the next 10 years would be 32 billion pounds, almost twice as much as the level of investment in the past 20 years (Ofgem, 2010). Taken into consideration the 2050's scenario, which also includes electrification, the electricity network cost is estimated to be 43 billion pounds (ENA et al., 2016). For Germany, dena

(2012) estimated that the costs for network investments at the distribution level may sum up to 27.5 to 42.5 billion Euro by 2030.

Given that large-scale investment is required to expand the grid, the regulator also needs to consider the risk associated with such investment. For example, the scale of risk can be described as the ratio of CAPEX of the planned investment to the existing regulatory asset value (RAV) of the network companies.[1] For some network companies, the CAPEX-RAV ratio for their asset is larger than that of the former regulatory period, because the network companies need to invest into the conventional grid to integrate wind energy (dena, 2012).

Traditionally, the network operators invest in physical network to cope with increasing demand. Currently, however, the need for the network expansion is mostly driven by changes in the supply structures due to increasing RES and DER. Accordingly, the network companies need to reinforce their networks in absence of demand growth. As a result, the unit costs of the network could increase, and investments would appear inefficient by the regulatory design even if they are required to foster the structural change in the supply structure.

Currently, network operators may also invest in smart grid solutions, utilizing flexibility provided by DER and digital technologies to manage the output from RES. In this environment, network companies could adopt e.g. “active system management.” Smart grid solutions are expected to reduce the needed amount of investment in the physical network (CAPEX), while increasing OPEX in the short run, though there are some uncertainties with respect to the effectiveness of such solutions. There is a wide range of technological options for smart grid, for example congestion management, storage, and demand response. However, they keep changing with progress in research and development, and thus, network companies are exposed to the risk of choosing appropriate technology. Additionally, in order to respond to variable RES and to provide high quality service to the consumers, TSOs and DSOs collect and make use of large amounts of data. This requires constructing interfaces for exchanging data among network operators. Since utilities progressively adopt business models that connect generation, transmission and distribution of electricity to IT systems (smart grids), these grids are more vulnerable to cyberattacks (CEDEC et al., 2016). It is one of the risks evolving as technology develops. Therefore, the network companies need to create or improve their power system’s resilience by using protective techniques and different operational resilience enhancement strategies alongside with the smart grid technologies against increasingly serious cyber threats. When the network operator invests in new technology under uncertainty, the time period from the implementation of this technology up to its maturity needs to be considered in the risk evaluation.

[1] In the UK, Ofgem estimated these ratios to analyze cash flow risk of energy transmission companies. Since the ratio is one of the indices for rating companies, it will affect the cost of capital for network companies. See Ofgem (2012).

These changes in the investment requirement raise a fundamental question of the necessity to revise the regulatory price control framework for the network companies. In particular it has been pointed out that incentive regulation on efficiency improvement needs to be reconsidered in order to accommodate the investment need of the network companies under massive integration of DER into the electricity system. For example, Agrell et al. (2013) state that “it is clear that the European predominant regulatory model of revenue- or price-caps, is challenged in its fundamental assumptions.” In addressing such challenges, Ruester et al. (2014) present two regulatory mandates: first, the regulation must account for the increasing total cost of distribution, considering not only the grid reinforcement, but also possibly increasing losses and investments into related infrastructures. Second, regulation must concurrently incentivize an active system management in order to cushion these costs. Additionally the authors suggested that sound regulation has to account for (a) changing OPEX and CAPEX structures, including also new types of assets and respective CAPEX categories, (b) the optimal choice among the latter; that is, how DSOs can be incentivized to find the optimal trade-off between using DER and upgrading (or building new) lines, and (c) how to incentivize DSOs to deploy innovative solutions and operating procedures. As specific improvements, they suggest the prolongation of the regulatory period, a higher focus on measurable output definitions and on corresponding DSO performance indicators.

Ruester et al. (2014) also mention that the focus of regulation must shift from achieving operating efficiency gains towards facilitating the achievement of environmental and supply security objectives. Although the Council of European Energy Regulators (CEER, 2018) emphasizes that there should be a balance between being investment-friendly on the one hand and affordability (i.e. cost efficiency) on the other, it seems to be a challenge not only for the regulator but also for the stakeholders, including network companies themselves.

2.2 Experiences of regulatory reforms for electricity networks in Germany and the UK

In response to the recognition of the challenges described above, some European countries modified a part of the procedures within the framework of the revenue cap. In this section, we describe the recent reform of the network regulation in Germany, where the regulation was reformed in response to the increasing need of investments. We also discuss the output-based regulation established in the UK as a new incentive framework of revenue cap regulation.

2.2.1 Revenue cap regulation in Germany.

The revenue cap regulation in Germany was introduced in 2009 with a five-year regulatory period. At that time, emphasis was placed on the efficiency improvement of the energy network. The number of DSOs is about 900 and there was a serious concern about the efficiency gap among those DSOs.

Under the revenue cap, allowed revenue for the network company is determined based on the actual cost (OPEX and CAPEX) of the "base-year", that is two years before the new regulatory period begins. The regulator - the German Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (Bundesnetzagentur, BNetzA) conducts efficiency benchmarking to set individual efficiency target for each DSO for controllable cost in TOTEX by using efficiency analysis techniques. This so-called individual X-factor is set in addition to a general X-factor that covers future expected productivity changes and equally applies to all DSOs (as well as the TSOs). Inefficient network companies are required to eliminate their inefficiency by the end of the following regulatory period, i.e. within 5 years. Regarding the incentive-based revenue calculations there are two exemptions, however. First, there is a distinction between "controllable" and "non-controllable" cost. The latter is considered to be (at least partly) outside of managerial control of the network operator. It is usually treated as pass-through and is not explicitly subject to the efficiency incentive scheme. Second, cost for investment (CAPEX) is treated differently from OPEX. Recognizing the large investment needs, the regulator has introduced a yearly true-up (adjustment) for changes in capital costs. By eliminating the time-lag of cost recovery, investment incentives should be increased. In case of TSOs, this true-up only applies to expansion of networks (so-called "investment measures"), and in case of DSOs this rule applies to all investments ("CAPEX true-up" or "Capital cost adjustment") from the third regulatory period (ARegV §10a). Both mechanisms temporarily exclude CAPEX from the efficiency requirement during the ongoing regulatory period and treats it as non-controllable costs which are remunerated as pass-through element. For CAPEX true-up, in the subsequent regulatory periods, the cost will become part of the regular efficiency benchmarking in order to avoid incentives for over-investment.

2.2.2 RIIO regulatory framework in the United Kingdom

In the UK, incentive regulation in the form of a revenue cap regulatory framework, called "RPI-X", was introduced when the network utilities in the telecommunications, gas, and water industries were privatized in the late 1980 and in the electric transmission and distribution sectors beginning in 1990. The RPI- X regulatory framework set a company's allowed revenue for a five-year term and allowed prices to adjust to inflation and expected efficiency gains within this period. This incentive regulation was generally perceived as success in terms of costs reduction, while not deteriorating the quality of supply. However, in light of new challenges such as the low-carbon transition, aging infrastructure, growing demand for grid expansion and smarter networks the Britain's energy regulator Ofgem decided in 2010 to replace the RPI-X regulation with a new performance-based framework called the RIIO model (standing for "Revenue = Incentive + Innovation + Output") and in that way to foster greater investment and needed innovation (Ofgem, 2010).

It consists of four main features: 1) eight -years regulatory period, 2) the total expenditure (TOTEX) approach to remove any CAPEX-OPEX bias that may occur, 3) specific performance incentives based on six output categories and uncertainty mechanisms, and 4) specific innovation incentives (an innovation fund). The current price control periods for the RIIO model run from 2013-2021 (for electricity transmission) and 2015-2023 (for electricity distribution).

According to this new regulatory framework, allowed revenue is partially linked to the performance of selected outputs in terms of delivering of a sustainable energy sector and ensuring value for money. The network operator gets rewards, when it delivers outputs on lower costs and innovation or penalties, when under-deliver the defined outputs and innovation. For a detailed overview over the main components of the RIIO framework see the Figure 1.

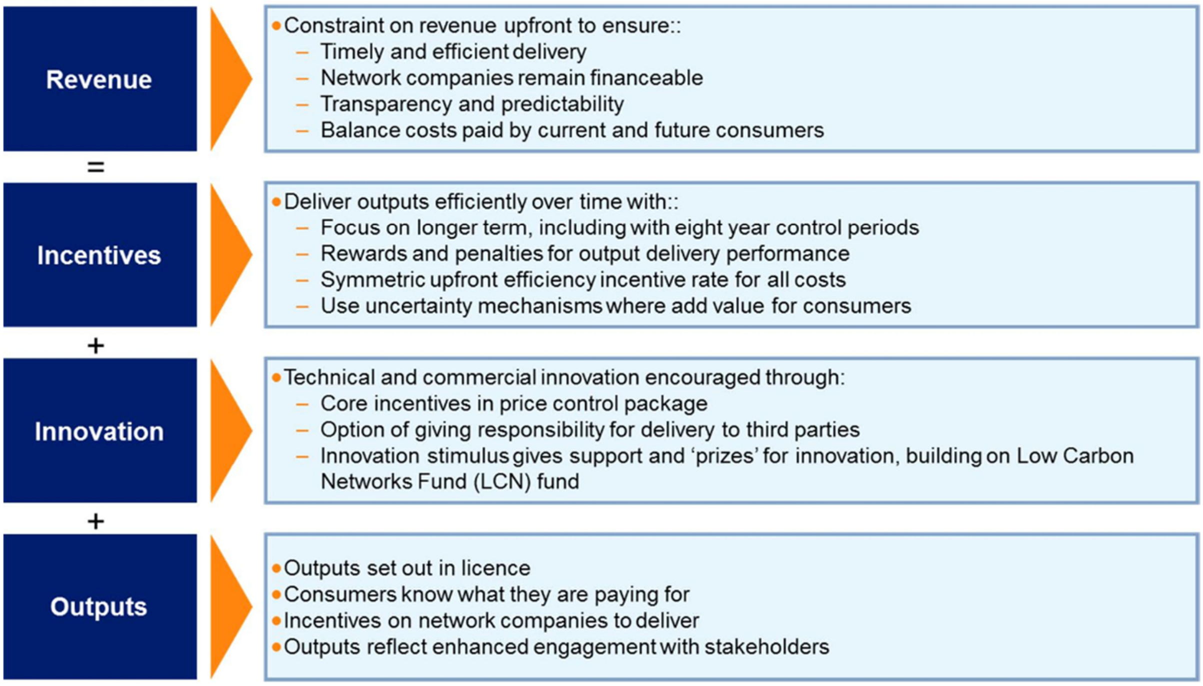

Figure 1: Main components of the RIIO framework

Source: Pöyry Management Consulting. Overview of RIIO-Framework, 2017, p. 17.

The network operators must meet the following six output categories: reliability and availability, environment, connections, customer service, social obligations and safety. Each output category is determined by the regulator, but specific outputs are proposed by network companies after the stakeholder engagement process. Figure 2 shows one example of company-specific incentives based on outputs for National Grid. Thus, it maintains the framework of the incentive regulation in the form of the revenue cap, but the way they assess the allowed revenue has fundamentally changed from cost (input) to output-based incentive regulation.

Category	Output	Incentive
Safety	Compliance with safety obligations set by the Health and Safety Executive (HSE). Supported by measures of asset health, condition and criticality with agreed targets and impacts on RIIO-T2 funding.	Statutory requirements. No financial incentive. A penalty/reward of 2.5% of the value of any over/under delivery of network replacement outputs.
Reliability	Primary output based on Energy Not Supplied (ENS).	Incentive rate of £16,000/MWh which is based on an estimate of the value of lost load (VoLL). A collar on financial penalties limiting the maximum penalty to 3% of allowed revenues.
Availability	Prepare and maintain a Network Access Policy (NAP).	Reputational incentive. Potential financial incentives if relevant during development and update of NAP.
Customer Satisfaction	Develop customer/stakeholder satisfaction survey.	Up to +/-1% of allowed revenue.
	Effective stakeholder engagement.	Up to 0.5% of allowed revenue via a discretionary reward scheme.
Connections	To meet existing legal requirements.	General enforcement policy.
Environmental	SF6 – Baseline target calculated annually with best practice 0.5% leakage rate for new assets installed.	Differences to baseline subject to a reward/penalty based on the non-traded carbon price for carbon equivalent emissions.
	Losses – Publish overall strategy for transmission losses and annual progress in implementation and impact on transmission losses.	Reputational incentive.
	Business Carbon Footprint (BCF) – Publish BCF accounts at business level annually over RIIO-T1.	Reputational incentive.
	EDR Scheme – measures to focus on aspects of the roles of the TOs and SO not explicitly captured in RIIO-T1 incentives.	Positive reward available if achieve leadership performance across different scorecard activities.
	Visual amenity – to efficiently meet planning requirements for new infrastructure and deliver visual amenity outputs by mitigating impacts of existing infrastructure when it is located in designated areas.	Reputational incentive in the context of its performance in the utilisation of two mechanisms: (1) baseline and uncertainty mechanism funding for additional cost of mitigation technologies required for development consent (2) initial expenditure cap of £500m to reduce the impact of existing infrastructure in designated areas.

Figure 2: Output categories and incentive parameters under RIIO-1 for National Grid.

Source: Ofgem (2012).

According to Ofgem, the RIIO regulatory framework can make electricity networks smarter and accelerate the development of a low carbon energy system (Ofgem 2010). By remunerating pre-defined outputs, it aims to facilitate long-term investment and innovation required to tackle the challenges for low carbon networks as long as they bring value-for-money to the network users.

In practice, however, it seems to be difficult to evaluate the value of outputs precisely. Besides, certain outputs related to operational efficiency are heavily incentivized compared to others, such as environmental outputs. In the decision of RIIO-2 framework in 2018, Ofgem made it harder to receive rewards for outputs that network company should deliver according to their license. Since the RIIO regulatory framework is quite new to the electricity network industry and consumers' bill increases, it seems that the regulator needs to consider some premises:

- As a process of applying output-based regulation, trial-and-error should be permitted in the sector. Although it is too early to evaluate the outcome of RIIO, some benefits and errors during the first regulatory period were clarified in the UK (Ofgem, 2018b and CEPA, 2018), but the same results would not occur in other countries. This is because the institutional design of the RIIO is so complex that the various factors interact with each other.
- Given that trial-and-error is inevitable, regulatory stability would be sacrificed for the time being. For some countries, this would be acceptable, if they desire the change of the regulatory framework rather than regulatory inertia (Lockwood et al., 2017). On the other hand, it will discourage large investment projects, because the network company would be unable to develop a plan with long-run perspective.
- Since the concept of output for electricity network is untested and those investments could be a large amount, gaining the understanding of users and rate payers are crucial. Friedrichsen et al. (2014) mention that *"with the diversification of actors actively involved in the energy system, high investment needs ahead and a blurring boundary between regulated and competitive markets, stakeholder involvement may be favorable in regulation in smart systems as well."* In the conventional process, prices (revenues) are determined by the regulator instead of signals in the competitive market. It was because the *"regulator knows best"* (Friedrichsen et al., 2014). On the other hand, if the regulator adopts the concept of outputs, it would be better to discuss with related stakeholders on what output should be delivered.

As in the UK, a huge potential for achieving the decarbonization targets needs to be realized in many countries. In order to incentivize the movement of the electricity sector toward decarbonization regulatory changes are required

2.3 Review of discussion for regulatory reform for electricity networks in Japan

The future investment needs for electricity network in Japan is expected to be driven by the government's energy policy to introduce maximum possible amount of RES transformed as a "major class of electricity generation". Although, in the future energy mix the government is aiming for, the target level of RES output (kWh) is 22-24% by 2030, there has been a rapid increase in RES, especially PV (about 50 GW as of March 2019), thanks to the government support through FIT, and in some regions, the capacity of PV exceed the peak demand for electricity during the low-demand seasons.

In addition, the government recognizes the need to strengthen the resilience of the network for which DER is expected to play an important role,[2] to cope with aging infrastructure, to incorporate the advances in digital technology, and to deal with uncertainty of the growth of future electricity demand.

Although the government has not indicated exact amount or value of investment needed, it recognizes that new investment is required, which would lead to an increase in cost to be borne by the network users unless the demand for electricity grows at a similar pace.[3] It has been emphasized that facilitating smarter network investment and radical cost reduction of the existing network are both important, as well as giving the incentive for generators, including RES, to seek cost minimization of the network and to reduce total cost of electricity supply.

Although the smartness has not been clearly defined, the transformation to a smarter network should be realized as a result of the value of the network being centered around the value of capacity and balancing, and cost reduction to be enabled by incorporating the external resources (RES and DER) into the network[4].

It seems that the amount of investment required to address those issues is uncertain and unpredictable, making at least some types of investment risky. On the other hand, at least a part of smarter network investment would alleviate the problems associated with the large amount of risky investment. For example, investment in the digital infrastructure would help the network companies to procure and operate external resources for solutions to the efficient use of the existing network (smartness, or non-wire alternatives). It will also reduce the amount of investment required or defer a part of it. The solutions enabled by the new smart technologies will increase OPEX instead, but the cost savings from the avoided or deferred investment would outweigh this increase. However, the effectiveness of such smart solutions is also uncertain, and the investment in these new technologies is even riskier than that of traditional types of investment.

To facilitate the necessary network investment while reducing cost to network users, the economic regulation of network tariff is crucial. The network revenue in Japan has been regulated by the traditional cost-of-service regulation. Although the way it is implemented gives the electric companies some incentive for cost efficiency (i.e. through the regulatory lag), it was recognized that such incentives were relatively weak and that the practice of cost review may not work to reflect the unpredictable cost of future investment.

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[2] This was motivated by a black out in Hokkaido area in September 2018 caused by Hokkaido East Iburi earthquake and a series of outages due to extreme weather event such as typhoon in 2018 and 2019.

[3] Currently, the generators do not have to pay network charges, but they will have to do so from 2023.

[4] In Japan, transmission network and distribution network are owned and operated by the same regional company. The voltage levels that distribution system in Japan is responsible for ranges from 0.1kV through 6.6kV, while the transmission system covers 33kV through 500kV. In Germany, distribution system typically covers 0.4 kV through 110 kV.

The government has indicated its intention to replace the current cost-of-service regulation with incentive regulation in the form of revenue cap to give the network companies cost-reducing incentives. Within the framework of revenue cap, the government also considered some uncertainty mechanisms to facilitate necessary investment by mitigating the risk of the companies. Then, the government studied the current practice of network regulation in Europe, especially those of Germany and the UK, and recognized the need for various uncertainty mechanisms during the regulatory period and some measures to promote new investment for smarter network.

3 The length of the regulatory period

One of the important elements of the incentive regulation is the length of the regulatory period that the regulator to commit to the pre-determined formula regardless of the actual profit of the network companies. During the regulatory period, the network companies cannot request the revision of the formula set by the regulator and change the level of cap even if they suffer from loss. It is one of the features of revenue (price) cap regulation compared to cost-of-service regulation.

Table 1 shows the regulatory periods of incentive regulation adopted in European countries. Many of them opted for a four- to five-year period.

Table 1: Regulatory period of incentive regulation in Europe

Three-year	Four-year	Five-year	Six-year	Eight-year
Czechia [T,D]1) Portugal [T,D]2)	Belgium [T,D] Finland [T,D] France [T,D] Hungry [T,D] Luxembourg [T,D] Sweden [T,D] Greece [T]	Austria [D]3) Denmark [D] Germany [T,D] Island [T,D] Ireland [T,D] Lithuania [T] the Netherlands [T,D]4) Norway [T,D]3) Poland [D] Romania [T,D]3)	Spain [T,D]	the UK [T,D]5)

Note: [T] is for transmission operators, and [D] is for distribution operators. 1) It actually extends to five-year. 2) It is a hybrid of incentive regulation and rate of return. 3) It is price cap regulation. 4) It is allowed to change by law from three- to five-year. 5) It will be five-year from the next regulatory period.

Source: Based on CEER (2020)

Below, we will discuss the pros and cons on the duration of the regulatory period, which typically differ between different stakeholders. With 8 years, the UK adopted the longest rate period when it started RIIO-

1 in 2013 (for Transmission Operators) with an aim to incentivize longer-term investments that are needed in the transition to a modern grid. We will give a brief overview of the pros and cons of a longer-term regulatory period and review the experiences of RIIO-1 in the UK below.

3.1 Pros and cons of longer regulatory period

First, the longer-term regulatory period should promote investment and create long-term benefits as in the case of smart grid. It sets in motion a process for the network operators to develop a long-term business plan and implement it under a longer regulatory period. On the other hand, under the longer regulatory period, the risk that actual expenditure exceeds the allowed revenue would increase. In addition, it would raise the risk that an unexpected event may occur that the regulator may not be able to handle immediately. The regulatory framework has limited regulatory flexibility. Moreover, it would be difficult to forecast the future needs of investment, as it is also influenced by the market risks (i.e. amount of RES to be connected to the network may change). Thus, the impact of longer regulatory period on investment is not clear.

Second, the longer regulatory period gives stronger incentives to network companies to reduce cost, as they are able to keep the profit margin for a longer period. However, this is a downside for consumers as they do not gain from cost reductions for a longer time period. We explain this situation in more detail later. On the other hand, as the actual costs can be higher than the allowance, consumers may benefit from the lower level of the cap during the longer period; they would, however, face the risk of sharp increase of the network tariff in the next regulatory period.

Third, the longer regulatory period could decrease regulatory cost. This is also a benefit for consumers who bear the administration costs. Under the short regulatory period, a more frequent regulatory review would increase administration costs for the companies and the regulator, as they need to go through the long administrative process to make decisions on network companies' business plans. The longer regulatory period would also reduce regulatory risks for network companies in resetting the cap (cost review) after the regulatory period. Even if the unexpected event (such as change of policy, change of trend of technology, change of consumers preferences, etc.) takes place, regulator is supposed to commit to the cap and the formula. Although the long regulatory period would save the regulatory cost, it might bring problems for both the regulator's and the regulated company's workflow. Since there is a long lag to the next cost reviews, it would make it difficult to retain skill of determining the appropriate cap and preserve corporate organization's memory (Regulated Industries Commission, 2010).

In case of Germany, where the allowed revenue was until recently determined based on the historical cost, the time lag of cost recovery of investment associated with longer regulatory period was a serious issue for the network companies. Since the initial allowed revenue for a 5-year regulatory period is determined based on the cost of two years before the periods starts (base year), the cost of additional investment made in the year after the base year could only be recovered in the next regulatory period. Therefore, the network companies had to wait up to 7 years to recover the cost. As in Germany, if the cap is determined based on the historical cost, the long regulatory period might decrease profitability and, hence, incentives for large investments (see dena, 2012; Nykamp et al., 2012).

3.2 Experience of UK with eight-year regulatory period

With the latest innovation of the electricity network regulation based on the RIIO-model in 2010, Ofgem implemented an eight-year price control period among others to encourage the smart grid investment and innovation, increase revenue certainty and raise awareness of benefits of transitioning to a low-carbon society in the future. This is the longest regulatory period adopted for revenue cap regulation for electricity network in European countries.

According to interviews with network companies by CEPA (2018), it seems that there is an actual benefit for many network companies to manage long-term investment projects.[5] For instance, network companies could negotiate longer term contract with the third parties, which is recommended under the RIIO regulatory framework, resulting in reduction of overall costs. It is also effective for innovation and efficiency, increasing investor's confidence. Moreover, the network companies could spend more time on managing their performance instead of engaging in negotiation with Ofgem. This shows that the long regulatory period seems to promote cost reduction as well as investment as intended by the regulator. In addition, in the long run, the scale of cost reduction under longer regulatory period would be larger than under shorter regulatory period.

In the discussion on the regulatory framework, however, the problem associated with long regulatory period especially for consumers were emphasized. Consumer groups, such as Citizens Advice, criticize that the network companies retained huge profit through RIIO-1 without passing on the benefits to consumers.[6] Ofgem prioritized the benefit of consumers and indicated that the extra earnings should be shared with consumers as soon as possible. Consequently, the regulatory period for RIIO-2 was determined to be shorter, five years, as the former price control period.[7]

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[5] Through the consultation for RIIO-2 framework, only one network company, ESO, support a shorter regulatory period. The reason is that the pace of change in the energy system is exceptional, and given the ESO's central role in the market, the ability to adapt to meet the needs of customers and stakeholders is vital. See National Grid (2018).

[6] Network companies earned double-digit returns (Ofgem, 2018a).

[7] This regulatory period is recognized as default. Ofgem prepare an option for applying longer price control period depending on network company's business plan to deliver longer-term projects or innovation. In such cases, the network company is required to submit the evidence of much significant net benefits to consumers than net benefits under the default price control period (Ofgem, 2018b)

This might be a political compromise. The profit might have been realized due to an error of forecast of cost to deliver outputs, but this is the risk to induce the efficiency improvement. Ofgem indeed stresses the benefit of the eight-year regulatory period and argues that the profit largely came from the network companies' effort to improve efficiency (Ofgem, 2018b). Yet, given significant uncertainty, the price that consumers pay may strongly deviate from the cost, and consumers would not be willing to accept such a situation for years. In words by Gómez (2013), in general, four or five years is normally a good compromise, "as it leaves sufficient time to create incentives for the company to lower its costs (productive efficiency) without running the risk of prices or revenues deviating too far from costs seeking both financial viability for the utility and cost-of-service efficiency for consumers."

4 Efficiency and productivity requirement: X_{GEN}

Typically, under price- or revenue-cap, also known as RPI-X-regulation, some level of efficiency and/or productivity requirement is considered in the formula; the productivity developments is denoted by the X-factor. It was originally intended to mimic productivity development in the telecommunication industry relative to the macro-economic growth in competitive markets. The X-factor lowers the allowed revenues in order to pass through the efficiency gains to the consumers. The X-factor can have two variations. First, the individual X-factor, which represents the potential for any relatively inefficient firm to catch-up with the industry's most efficient firms (the efficiency frontier). Individual X-factors are usually determined with benchmarking technique. Second, the general X-factor, which represents the expected growth of the industry's (future) productivity (ΔTFP), which the companies are supposed to match. In the following, we concentrate on the developments of the general X-factor.

4.1 The recent trend of X-factor: a trend-break in the new millennium?

The general X-factor, X_{GEN}, is usually measured as the long-term trend of the change in total factor productivity (ΔTFP). The change in total factor productivity is defined as the change in output divided by the change in input; usually outputs and inputs are defined and calculated by some index.

The second half of the last century witnessed steady growth of TFP, but this seems to change. Lately, growth of electricity demand and thus network use (output) is slowing down or even declining and the energy transition requires massive network investment and causes costs (input) to go up. If output goes down and input goes up, total factor productivity decreases.

The case of the USA illustrates this well. In a 2017 case of network regulation in Alberta in Canada (esp. AUC, 2017) extensive long-term studies on the ΔTFP development were set up for this procedure; these were largely carried out by US consulting firms using the US data.

In an earlier case with the Alberta Utilities Commission (AUC), Nera Consulting, based on Makholm et al. (2010) conducted a TFP study for the US energy supply from 1972 to 2009. For the procedure in Alberta (AUC, 2017) for energy supply 2018-2022, this study was used, and the data was updated with additional studies until 2014. The data was routinely collected and processed by the US federal regulator FERC; here, they used 72 US utilities (electricity and electricity/gas companies).

The long-term trend of ΔTFP (in %) is remarkable and shows an important trend that is also noticeable in other countries. Figure 3 shows a consistently moderate TFP development up to around 2000; from 2000 TFP falls. This trend is due to the decline in output. The trend for the entire period from 1972 to 2009 therefore results in ΔTFP = 0.85%. In the new procedure (AUC, 2017) on the one hand the structural break in 2000 was explicitly taken into account and on the other hand the reference period was extended to 2014.

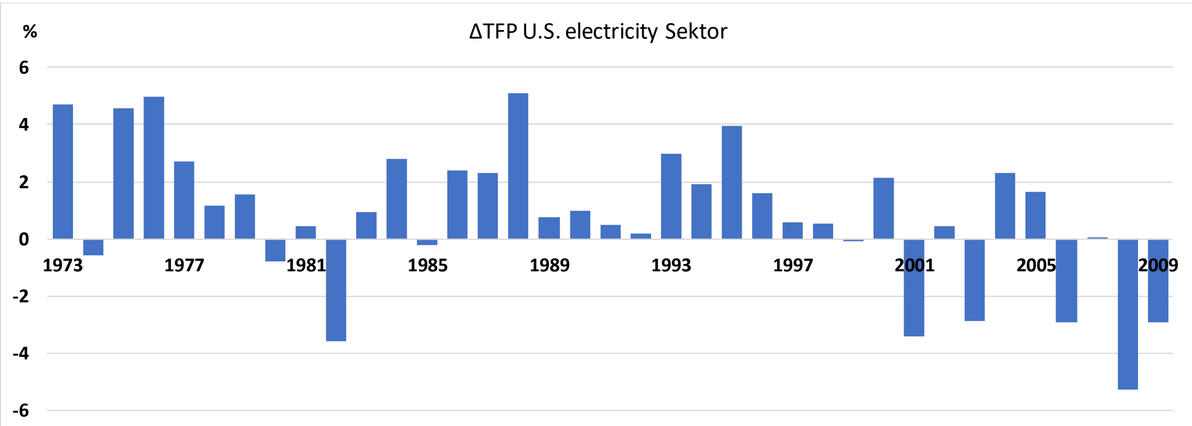


Figure 3: ΔTFP of the energy supply in the USA

Source: data from Makholm, et al., 2010.

Table 2 shows that the selection of the reference period is very critical. Considering a statistically determined structural break in 2000 and an expansion until 2014, the long-term trend of the ΔTFP is very negative, as compared to the long-term trend 1972-2009 which is positive. The main reason is quite obvious: demand has stopped growing around 2008.

Table 2: Updated data in the procedure at AUC (2017)

Study	Data period	No. of firms	ΔTFP (%)
Nera 2012	1972-2009	72	0.96
Brattle	2000-2014	67	-0.79

Source: adapted from AUC (2017, p. 23, table 1).

Australia presents a picture similar to that of the USA. The studies in Australia usually cover a somewhat shorter reference period, from around 2000-2014 or even from 2006 to 2014. A study for Australian Gas Network Limited (Economic Insights, 2015, p. ii)[8] summarizes the picture well: "The pattern of strong productivity growth during the period 1999 to 2008 and relatively flat TFP growth after 2008." Figure 4 shows this development.

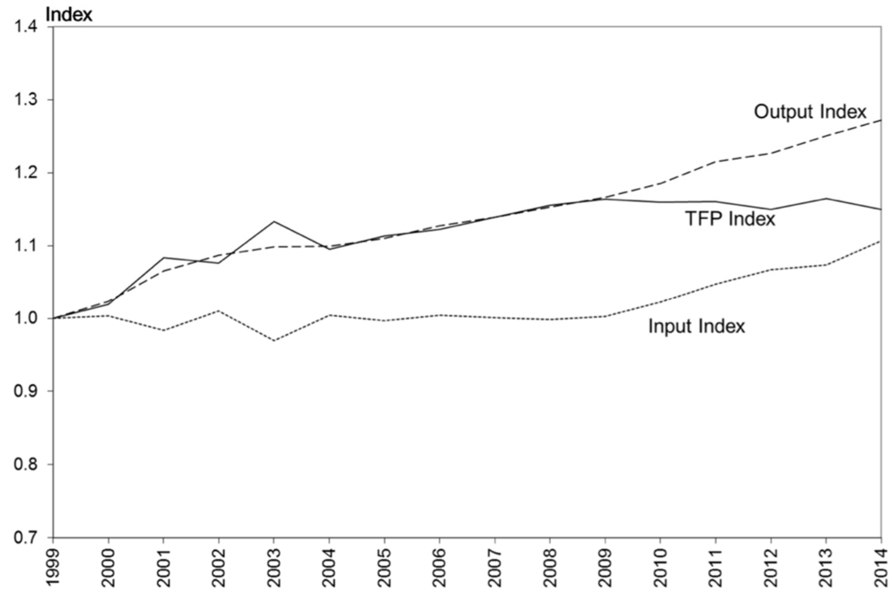


Figure 4: TFP index of AGN's gas distribution networks in Australia

Source: Economic Insights (2015, p. 17, Fig.3.1)

The numbers in Figure 4 do not show the developments before 1999. However, it is immediately apparent that the TFP index flattens out and even declines slightly from 2008. The trend breaks in 2008 appears evident: overall, the annual ΔTFP over 1999-2014 is positive, but especially in 2008-2014 this becomes

[8] Note: these numbers are for the gas networks, but we expect the general trend to be the same for electricity networks.

negative. The main reason, however, is the increase in input from 2008, while the input index is relatively constant until 2008.

We conclude that the times of steady growth of total factor productivity of the energy networks are gone, or at least pause for the moment. There are two main reasons. First, the rapid growth of total factor productivity in post-war years was driven by the constant growth of demand during the post-war electrification phase. Second, the current change of the trend seems to be driven, at least partly, by the energy transition.

4.2 The recent debate on the general X-factor in Germany

The energy network regulation in Germany also includes an X-factor, which in turn includes both the individual and the general X-factors. The general X-factors for gas and electricity network for the 3rd regulatory period have just been calculated by the regulator.

The BNetzA calculated the first X_{GEN} at 2.54% p.a. for the first and the second regulatory period. The BNetzA applied a Törnqvist method for the period 1977-1997 (leaving out the year 1992, as re-unification of former East- and West-Germany posed severe data problems). The data for the calculations comprised the entire value chain (not only the networks) of both gas and electricity. The network companies argued that it rather should be 0%, and after long discussion, the German parliament (*Bundesrat*) decided as a compromise to set the final X_{GEN} at 1.25% p.a. for the 1st RP and 1.50% p.a. for the 2nd RP.

For the 3rd regulatory period, the BNetzA managed to make the calculations for the networks only and separately for gas and electricity networks. The examined time period is 2006-2016 for the gas networks and 2006-2017 for the electricity networks. The BNetzA applied two methods: the Törnqvist-method and the Malmquist-method. The latter relies on a decomposition of the changes of overall efficiency, using benchmarking results of three different snapshots, into a frontier shift and a catch-up effect (cf. Meyer et al., 2020). Whereas theoretically, provided properly adjusted, the results of these two methods should be the same, in practice they were widely different (Bundesnetzagentur, 2018b, 2018c) and overall rather counterintuitive. The BNetzA acknowledges the uncertainties in the calculations and has chosen the lower value of both and in case of electricity deducted a safety margin of ca. 30%. The numbers are given in Table 3 below.

Table 3: Results of X_{GEN}-calculations by the German regulator BNetzA

Regulatory period	BNetzA calculations			Final decision
	Method	Calculation period	X_{GEN}	X_{GEN}
1st RegP (2009-2013)	Törnqvist	1977-1997	2.54	1.25
2st RegP (2014-2018)	Törnqvist	1977-1997	2.54	1.50
3rd RegP (2019-2023)[2]	Törnqvist	2006-2017	1.82	
	Malmquist	2006-2016	1.35	0.90[1]

[1] At the moment of writing, the process is not yet finished, and the final decision is pending.

[2] The numbers for the 3rd regulatory period provided here, are for electricity networks only.

Source: Bundesnetzagentur (2006, 2018a)

The calculations made by the BNetzA were heavily criticized by the network companies, which claim that X_{GEN} should be zero. The main point of criticism was the examination period starting in 2006. Upon close examination, it turns out that the data of 2006 are highly sensitive: small changes in the data trigger very large effects in X_{GEN}. Subsequently, the companies went to court. At the moment of writing, for the gas calculations, the court (OLG Düsseldorf) annulled the decision by the BNetzA, after which the BNetzA went to the high court in Karlsruhe; the decision of the high court is pending. For the electricity calculations, which were made somewhat later, the decision of the court (OLG Düsseldorf) is currently pending. In both cases, it is not unlikely that again parliament (*Bundesrat*) will have the final word.

4.3 X-factor in the era of smart grid

What would a negative X-factor mean for the incentive power; would it become ineffective? It would not. Meitzen et al. (2017, 2018) argue that negative X-factor is not a theoretical matter, but it just comes from empirical results, and the reason is obvious, considering the recent environment the energy network company is facing. As Meitzen et al. (2017, 2018) suggest, it does not mean that the incentive regulation would not work to induce cost efficiency. Whether the X-factor is positive or negative, under the cap the network company has an incentive to reduce cost in order to earn profits as much as possible.

If the rising productivity is expected, the meaning of the X-factor is to mimic competition and provide benefits to the consumers through price reduction. However, if the productivity, which is defined as the ratio of kWh-based output and expenditure-based input, is not expected to increase, the X-factor in future regulatory period would be negative as a result of calculation. It is a natural consequence of the required investment.

For the consumers, a negative X-factor indicates the price increase during the regulatory period. In the short run, it seems unavoidable, because the smart grid investments are not related to demand growth and involve high risk. The smart grid system is built for the social benefit in the long-term perspective, and thus it would necessarily need time to allocate the gain to the consumers[9]. In the era of building the smart grid system, price reduction by X-factor is not the only means to provide the benefit to consumers.

Since the future productivity trend is not the same as the past decades, the X-factor which is determined with ignoring the expected trend and based on the past data set would be too strict for the network companies to make appropriate decision for the smart grid investment.

5 Allowed rate of return

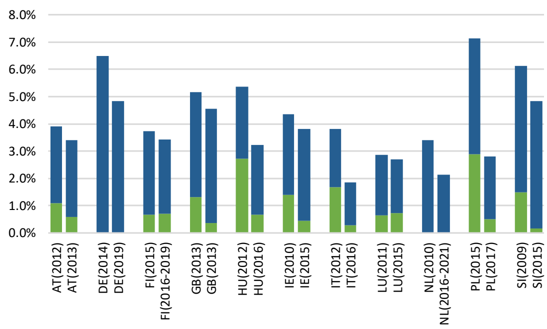
We focus on cost of capital in this section, because it is an important element that determines the level of the revenue cap and incentivizes investment. As CEER (2018) mentioned, setting a fair rate of return as a key in the financial breadth of regulation for the network companies is an important aspect in the regulation. Eurelectric (2010) also indicated that one of the most important characteristics of a regulatory system is the adequate rate of return.

The regulated companies can earn the cost of capital as fair return on capital or the regulated assets. It reflects the risk of the capital market that network companies are facing. In the following, firstly, we review the recent declining trend in the allowed rate of return for regulated companies in Europe. Then, we discuss the risk which network operators are actually facing to build the smart grid system and point out the importance of considering the risks and regulatory framework as a whole.

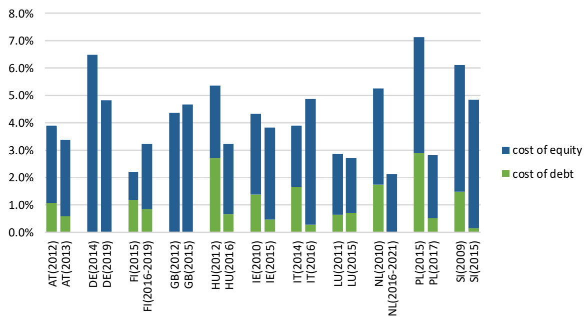
5.1 Declining trend of allowed return in the EU

Recently, the allowed rate of return for revenue cap has been declining in many of the European countries (Figure 5 (a) and (b)), The main reason for this is that the interest rates in the Europe are declining and the result of calculation of the CAPM reflects this trend.

[9] As the way to share benefit to consumers in the regulatory period, there is a measure called profit sharing as is implemented in the UK. If the network companies obtain large profits, then they share a part of profits to consumers.



(a) Electricity Transmission



(b) Electricity Distribution

Note: The figure for Germany is cost of equity.

Figure 5 Recent Changes in Weighted Average Cost of Capital (post-tax)

Source: CEER (2016, 2017) and regulators' reports

In Germany, the regulator sets only the allowed return on equity by using the capital asset pricing model (CAPM) based on the historical data[10], and the cost of debt is based on actual cost of interest of the network companies. For the third regulatory period, the rate of return was set at 6.91% for new equipment and 5.12% for old installed equipment. These rates of return were the lowest since the revenue cap was implemented. A series of lawsuits was finalized by a ruling of the federal high court in favor of the BNetzA[11]. The court made the decision based on the evidence of historical financial market, but the BDEW (the association of German network utility companies) made a statement against the decision, emphasizing the risk of the investment (BDEW, 2019).

In the UK, there is also a difficulty to set the appropriate allowed rate of return. A consumer group criticized against the seemingly higher allowed rate of return during the RIIO-1 (Citizens Advice, 2017). Ofgem stated that £6 billion will be cut from the cost of capital over the next RIIO-2. Ofgem forecasted the rate of return at 4.3%, with cost of equity ranging from 4.0% to 5.6% and the lower cost of debt. It is almost 50% lower than that of RIIO-1 and the level is the lowest in history (Ofgem, 2019a). UK network companies argued against the lowest level through the consultation of RIIO-2, since they were facing risks in changing environment.

[10] The method is same with the other 23 countries in EU. See Bundesnetzagentur (2016).

[11] The issues on the lawsuit case of the higher court is discussed by Haug and Wieshammer (2019a). On the reasons of the decision made by the federal court is summarized in Haug and Wieshammer (2019b).

Certainly, there is an argument that the allowed rate of return should reflect the risk that the network companies are facing. Under incentive regulation, the fact that there is a risk of cost recovery (Guthrie, 2006) might raise the cost of capital of the network companies (Pedell, 2010). It seems that the process of building smart grid system could involve huge risks. Question is whether the current allowed return is too low for the network companies to make those investments, as network companies claimed. Pedell (2010) indicated that the regulator should not necessarily set the allowed return higher than the actual cost of capital. That means, the evaluation of the actual cost of capital should be done carefully.

5.2 Issues of addressing the higher risk of smart grid

There are some cases for higher risk related to the cost recovery of smart grid investment. One of the risks is the time-lag of cost recovery of investment. If the network companies made a large investment for smart grid system, which had been unexpected at the initial point of regulatory period, the costs are recovered after the end of the regulatory period. The second risk of smart grid system is due to regulatory uncertainty. The network regulation is affected by the energy policy or political target of climate change. These policies change the requirement of network investment. It makes the network regulation unstable and complicated. The third risk is the stranded cost of new technology. In fact, DSOs invest in EV charging or storage facilities as an extension of their regulated role to adopt the smart grid system. However, the DSO's ownership of the facilities was restricted by the Electricity Directive to promote market-based incentives for the deployment of such facilities. For DSOs, who made anticipatory investment in the facilities, the cost recovery became a crucial issue (Meeus and Nouicer, 2018).

The above risks are related to the smart grid system, and DSOs therefore face an overall higher risk if they invest in smart grids than they would in case of conventional grids investment. Should this extra risk be considered explicitly in the allowed rate of return? The answer depends on the revenue cap framework, which is currently reformed in some countries. For instance, in Germany, as we mentioned before, the CAPEX-true-up has been implemented from the third regulatory period. It allows changing the cap annually according to the scale of CAPEX. Under the revenue-cap with the CAPEX-true-up, the network companies are able to start recovering the cost for the additional investment in the regulatory period. As a result, the risk of time-lag is mitigated.

An example of a regulatory design acknowledging uncertainty exists in the UK. The regulator, Ofgem sets lower allowed return to decrease the burden of consumers. At the same time, Ofgem recognizes that the network companies would face increased risk of the changing environment and their new role in the smart system. Thus, Ofgem decided to include various uncertainty mechanisms to lower the systematic risk.

To sum up, network companies are facing new risks for smart grid investment, however, the recent regulatory framework is also arranged to cover the risks. Under the standard incentive regulation, the risk premium would be higher than it would be under the rate-of-return regulation, because the cost recovery is not guaranteed. However, it does not necessarily apply to the recent revenue cap in some countries. In recent years, as European Commission (2019) mentions, the revenue-cap is changing to a system of rate-of-return regulation. That means that the risk of cost recovery is mitigated under the recent revenue cap by the adjustments as is done in the rate- of-return regulation. Then, the appropriate allowed return should be calculated by considering not only the various risks but also regulatory framework as a whole.

6 CAPEX-OPEX-incentive-bias

One debate that is gaining momentum is whether regulation unintentionally creates an incentive bias in favor of CAPEX and against OPEX. This is important for three reasons. First, smart grids usually rely on OPEX measures. A CAPEX-OPEX incentive distortion would therefore hinder the development of smart grids. Second, network companies are currently facing significant investment requirements, leading to a high CAPEX-OPEX ratio. As soon as the wave of investments is over, the CAPEX-OPEX ratio drops again and the activities will tend to be relatively OPEX-heavy. The regulation should therefore not distort OPEX incentives. Third, network operators are increasingly faced with OPEX-related tasks, e.g. network congestion management that increases with renewable energies.

The CAPEX-OPEX incentive bias is mainly mentioned in the practical debate and less in the theoretical literature. The UK water authority, Ofwat (2011, pp. 15-18) discusses the issue at length. EDSO (2017, p. 4) indicates a CAPEX bias for power distribution networks. Bade (2016, p. 10) refers to a state regulatory authority in New York that claims a CAPEX bias. The Australian Energy Regulatory Agency AER (2014) emphasizes its balanced and symmetrical treatment of CAPEX and OPEX to avoid distorting the CAPEX. Finally, the regulatory authority in Germany found sources for CAPEX-bias in the regulation (cf. Consentec & Frontier Economics, 2019).

The CAPEX-OPEX incentive bias has become known as the Averch-Johnson (AJ) effect (Averch & Johnson, 1962), also known as gold-plating or over-capitalization (see Knieps, 2001, for a formal exposition). The AJ-effect is typical for the regulation of returns and does not apply to cost-based regulation in general. The regulation restricts the return on capital employed, while operating expenses are subject to a direct cost pass through. If the allowed rate of return is larger than actual cost of capital, the firm has an incentive to inflate the capital base at the expense of operating costs, since the capital base determines the allowed profits. The inefficiency lies in the distorted ratio of CAPEX to OPEX, which is also referred to as CAPEX-OPEX incentive bias, or short, CAPEX-bias. The AJ effect is well known in the literature. However, it is empirically controversial, and it has not been convincingly shown to exist (see e.g. Borrmann & Finsinger, 1999).

In general, there are three possible sources for a CAPEX-bias. First, an advantage of the cost of capital, especially that the allowed rate of return is higher than the actual cost of capital: "s> r". Second, an OPEX disadvantage; Here one can think in particular of an OPEX-risk that is not fully captured in the regulation (Brunekreeft & Rammerstorfer, 2020). Third, the CAPEX-bias can be caused by details in the specific regulation. This is context sensitive and varies from country to country.

In Germany, the following sources of CAPEX-OPEX-incentive-bias can be identified in the ARegV:

- Investment measure (§23 ARegV), which concern the TSO. The main principles are that the CAPEX eligible for §23, is passed-through annually. In addition, there is a 0.8% OPEX-allowance, raising the revenue cap to compensate for increase operating expenses that go along with the investments. After the relevant regulatory period, the investment goes into the normal regulatory lag. The 0.8% OPEX-allowance drops away. This causes two separate CAPEX-biases. First, for CAPEX there are no negative, but only positive adjustment to the "base-revenues". There is no OPEX-equivalent for this and thus OPEX is less profitable. Second, increasing CAPEX raises the OPEX-allowance (without having to actually spend additional OPEX) as this is fixed share of CAPEX.
- The new principle of annual capital cost true-up for the DSO. The main principle is the annual cost-of-capital adjustment. The asset values are adjusted annually: depreciation is deducted, and new cost of capital added on an annual base. Figure 6 illustrates the mechanism. Under the CAPEX true-up, annual increased CAPEX is not subject to the productivity factor during the regulatory period. At the same time, there is no base compensations for CAPEX anymore, neither positive, nor negative. OPEX is treated separately and is still subject to a regulatory lag of five years. This may lead to a CAPEX-bias: CAPEX and OPEX are treated asymmetrically. CAPEX is not subject to a regulatory lag, while OPEX is. Hence, in expectation (if we cannot influence when the expenditure is made), OPEX is less profitable than CAPEX, due to the effect of the regulatory lag.

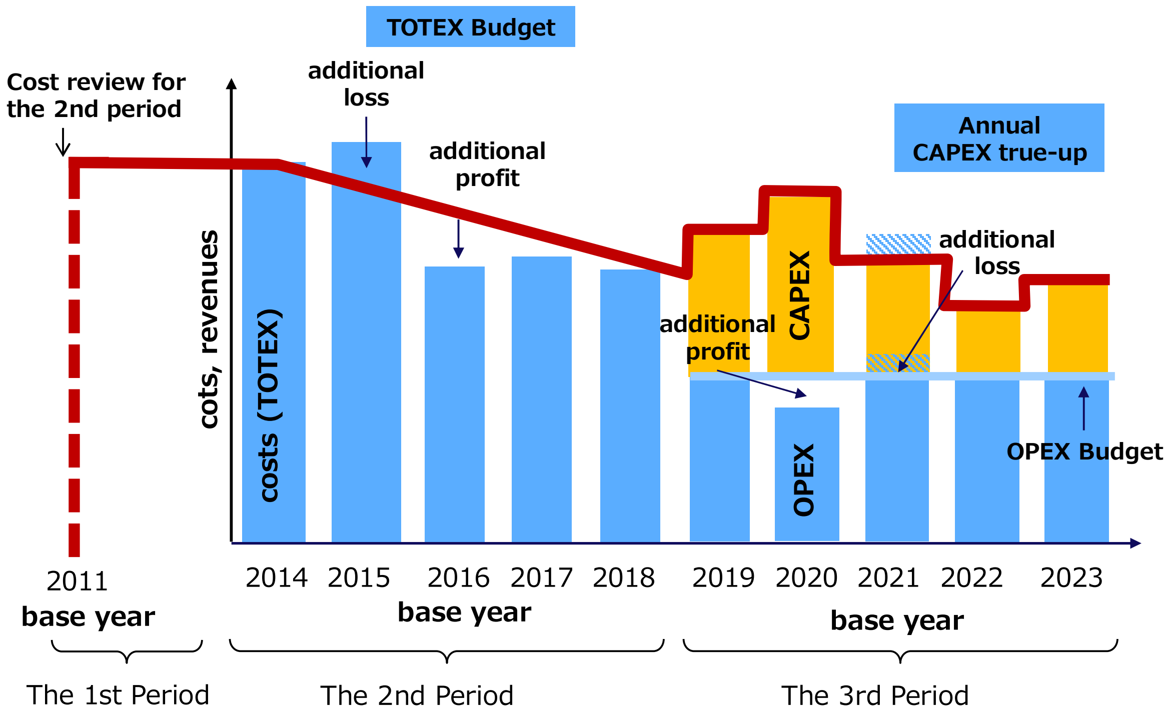


Figure 6: TOTEX approach with CAPEX Adjustment

Source: based on Bundesnetzagentur (2018c)

- Permanently non-controllable costs ("DnbK") are cost-pass-through and are outside the incentive regulation and are not part of benchmarking. A large part of this cost-pass-through is related to the costs for congestion management and redispatch, which have increased strongly due to the massive integration of renewable energy sources. In the case of TenneT as one of the four German TSOs, redispatch costs make up more than 40% of total cost. Figure 7 shows a massive shift in the cost structure toward non-controllable costs.
  Although these costs are assumed to be caused exogenously for electricity network companies, there might be a room for the network companies to manage the congestion cost to achieve the most efficient level. The incentive bias can go either way. First, the firm is completely indifferent regarding the DnbK; in as far as CAPEX is a substitute for the DnbK, the bias depends on whether or not CAPEX is profitable or not. Second, CAPEX is a part of benchmarking while the DnbK are not; hence, if CAPEX worsens the relative efficiency in the benchmark, the firm will opt away from CAPEX (cf. Consentec & Frontier Economics, 2019).

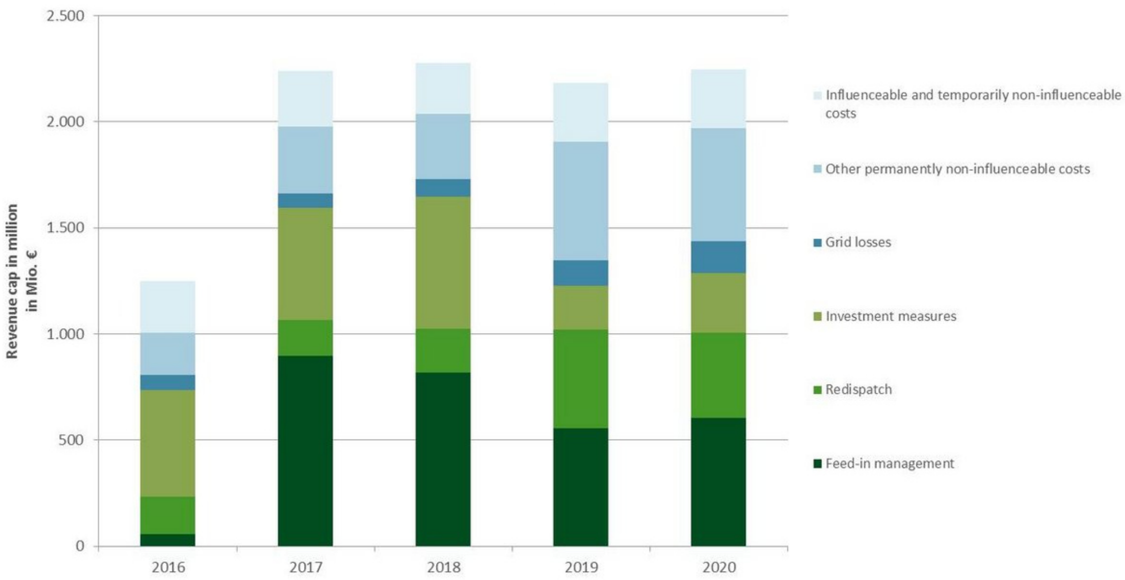


Figure 7: Shift of controllable to non-controllable costs in case of TenneT

Source: TenneT (2020)

To address the CAPEX-bias, the UK water regulator Ofwat and the energy regulator Ofgem developed a variation of the TOTEX regulation (Ofwat, 2011; Ofgem, 2017, p. 14/15, Oxera, 2019). A predefined fixed part of OPEX is activated and treated like CAPEX: a "fixed OPEX CAPEX share (FOCS)". In FOCS, all expenses, whether for capital goods (CAPEX) or operational measures (OPEX), are treated the same as TOTEX. A fixed portion, the capitalization rate of this TOTEX, is then "activated" (quasi-CAPEX) and the remaining part is treated as quasi-OPEX ("pay-as-you -go"). This capitalization rate is given: the fixed OPEX-CAPEX share. In the regulation, the resulting quasi-CAPEX and quasi-OPEX are treated in the same way as the CAPEX and OPEX in the normal system. The quasi-CAPEX flows into the regulatory capital base and generate depreciation and interest. The quasi-OPEX are booked within the book year. This way, the firm is c.p. indifferent between CAPEX and OPEX, and therefore the CAPEX distortion is internalized (Brunekreeft & Rammerstorfer, 2020).

7 Output-based regulation

We are at the brink of a new development: output-based regulation that supplements regulation with revenue elements that reflect the achievement of specific performance targets or benefits of predefined outputs. It emerged as an important ratemaking option that strengthens the performance of the network operators and provide the companies with greater operating flexibility. The outputs can be different categories that are intended to strengthen company's performance and include more than just efficiency. The outputs can be implemented in different ways and in different combinations. The common approach of this regulation worldwide includes a multi-year rate plan and some performance incentive mechanisms, including among others the revenue decoupling and earnings sharing mechanisms. Output-based regulation can incentivize activities that require cost increases and upfront expenses and capture externalities and, in that way, provide the companies with greater flexibility to meet competitive challenges and changing demands of customers. We should emphasize that the main idea is to keep a revenue cap in the regulatory core, but this is complemented by output-based components.

The theoretical background is emphasized in the pioneering work on quality regulation by Spence (1975, p. 420, footnote 5), in which he states: "Of somewhat less interest is the case where price is fixed or taken as given. In that case, the firm always sets quality too low." Note the difference between a shift in the cost curve and a shift in the demand curve (Figure 8).

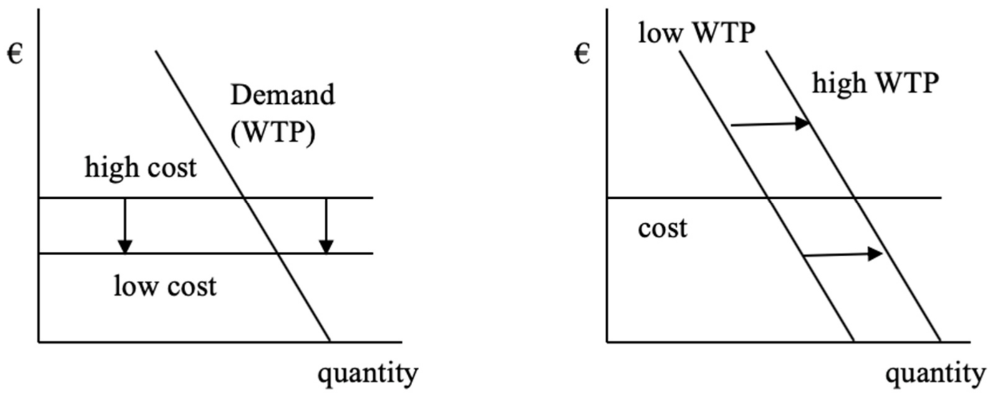


Figure 8: A shift in the cost curve versus a shift in the demand curve.

Source: own illustration

As efficiency improves, the cost curve decreases while demand remains constant. This is what price-based models aim at. Things change when the demand curve shifts: Some innovations improve the product so that consumers' willingness to pay (WTP) increases. As pointed out by Spence, price-based models, where the price is fixed, cannot handle this situation very well. If the demand curve is shifted, there is an additional surplus (the additional area below the demand curve): value creation. As the regulation caps prices, the company cannot make up for the additional surplus sufficiently and invests too little in product improvements. This is true whether the cost increases or not, but the problem gets worse if the cost increases.

The output-based regulation addresses this problem; it tries to define and quantify product improvement (the shift in the demand curve) using an output-metric and to link the additional consumer surplus with the additional profit for the company; thereby it strengthens incentives for additional value creation. The main implementation problem is to set the right incentives for the economically optimal result. First, which outputs should be incentivized? Second, what metrics should we use? Third, which incentive mechanism should we use? Fourth, how strong should the incentives be?

A widely cited output-based regulation system is the UK's RIIO-Model (Ofgem, 2010) already mentioned in section 2.2.2 above. There, the main output categories for the first round of RIIO price control are security, environmental impact, customer satisfaction, social commitments, connections, reliability and availability (Ofgem 2010). Besides the output categories, the framework includes an eight-year plan term, a TOTEX-based revenue regulation and innovative use of performance incentive mechanisms, including a fund to sponsor innovative pilot projects to test new technologies and an innovative rollout mechanism that reduce the risk of an innovation that may not provide sufficient company benefits.

In January 2020 Ofgem introduced its decision on the second round of RIIO price controls for distribution networks (RIIO- ED2). Based on this decision, Ofgem set a five-year price control period, in line with the other sectors and consolidated existing outputs into three new output categories: (1) meet the needs of consumers and network users; (2) maintain a safe and resilient network; and (3) deliver an environmentally sustainable network (see the Figure 9). To deliver these three outputs, Ofgem set out a framework that will establish minimum standards of performance set in the Licence Obligations (LOs), and rewards and penalties for non-delivery expected outputs. Additionally, Output Delivery Incentives (ODIs) could be applied to the outputs where they will drive value for consumer and other networks users (Ofgem, 2019b, p. 12).

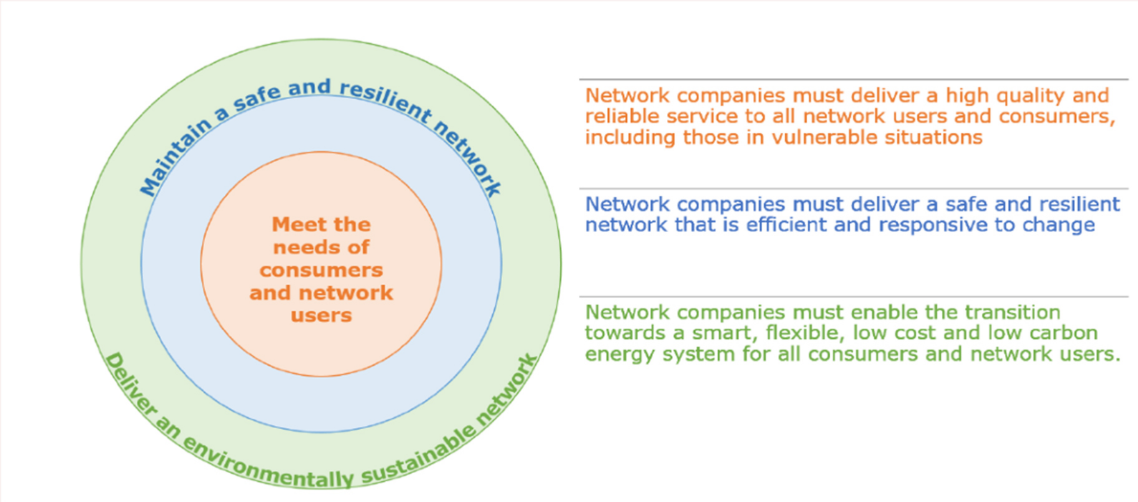


Figure 9: Output categories in RIIO-2

Source: Ofgem, 2019b, page 12.

In the United States, basic incentive regulation is called performance-based regulation (PBR); complementary to basic PBR, the regulators apply so-called targeted performance incentive mechanisms (PIMs). NREL (2017, p. x) defines PIMs as: "a component of a PBR that adopts specific performance metrics, targets, or incentives to affect desired utility performance that represents the priorities of the jurisdiction. PIMs can be specific performance metrics, targets, or incentives that lead to an increment or decrement of revenues or earnings around an authorized rate of return to strengthen performance in target areas that represent the priorities of the jurisdiction." They provide greater regulatory guidance and financial incentives to address new policy goals such as grid modernization or improvement of customer service and mitigate current financial incentives that create CAPEX-OPEX bias. They also involve lower operating risks and can provide the network operators with new earnings opportunities.

NREL (2017, p. xii and pp.61 ff.) provides a list of PIMs in operation in the US electric utility industry. To mention a few, which are or can be of interest for the network operator:

- Incentives for implementation of renewable energies
- Renewable energy performance metrics
- Operational incentives: improved interconnection request response times
- Operational metrics: incentives to improve reliability
- Incentives to support competition

To sum up, the output-based regulation offers several mechanisms that provide flexible incentives that may solve problems related to the changing market conditions. It concentrates more on outputs instead on inputs. However, this regulation can be complex and resource intensive. Therefore, the successful implementation of the output-based incentives depends on how well existing regulation is working and the extent to which regulators and stakeholders are ready to accept the risks and transitional costs associated with this incentive framework. Currently, the development of the output-based regulation is just beginning; many implementation problems and potential areas still have to be identified and improved and are topics for further research.

8 Conclusion

We examined selected issues of revenue-cap regulation to promote efficiency as well as investment in smart grid systems. Since building a smart grid system requires a combination of conventional investment and smart solutions under uncertainty, the regulatory system is needed to encourage the network companies to optimize their smart grid investments.

The regulatory period is one of the important elements of incentive regulation to give network companies the incentive to reduce cost and make appropriate investment planning. In order to promote long-term investment as is the case in smart grid, the longer length would be suitable. In practice, it needs to be shorter to return the gain to consumers as soon as possible. European experience suggests that the maximum five-year period is considered to be a good compromise.

The general X-factor is another important feature of incentive regulation. As a consequence of large expenditures to connect massive RES without large demand growth or cost-reducing innovation, the X-factor tends to be set lower in many countries. Even with a lower X factor, under the revenue cap regulation, the incentive for cost reduction of network companies does not diminish, and even though the immediate reduction of price may not be possible, the customers will benefit from smart grid in place in the future.

The allowed rate of return in the revenue cap could affect the decision making of investment for network companies. Reflecting the current situation of capital market, the allowed rate of return in European countries are set lower than historical level. Smart grid investments are sometimes claimed to involve higher risk and the allowed rate of return may not be high enough to compensate for such risks. However, it has to be noted that some elements of the recent regulatory design mitigate the investment risks associated with smart grid.

Recently in Germany, the reformed incentive regulation includes at least partially the essence of traditional cost-based regulation to promote capital investment. A drawback of this system is the CAPEX bias. A further source of CAPEX-bias is OPEX-risk. To repair the CAPEX-bias, the so-called fixed OPEX-CAPEX share is an interesting option.

The new concept of output-based regulation offers several mechanisms that provide flexible incentives to solve problems related to the changing market conditions, by focusing more on outputs rather than inputs. Yet, implementation is complex. and more work is necessary to design effective output-based regulation.

In the era of smart grid, setting the conventional parameters for incentive regulation, such as a length of the regulatory period, X-factor, and the allowed rate of return, becomes more complex. It requires a long-term perspective and needs to address the regulatory risks and uncertainties related to investment into grid expansion and smart grid technologies. In doing so, the more stable, predictable and innovative investment-friendly regulatory measures should be implemented into the incentive regulation. The incentive regulatory framework needs additional supplementary mechanisms such as output-based regulation to achieve the regulatory goals and to develop fully-functional and consumer-oriented smart grid, so that both the network operators and their customers could benefit from it, though details for implementation still have to be worked out.

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