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ECONOMIC REGULATION OF DISTRIBUTION SYSTEM OPERATORS AND ITS ADAPTATION TO THE PENETRATION OF DISTRIBUTED ENERGY RESOURCES AND SMART GRID TECHNOLOGIES

Tesis para la obtención del grado de doctor

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Resumen

Esta tesis hace una revisión de la regulación económica de la actividad de distribución eléctrica. Como resultado de la misma se discuten y proponen adaptaciones necesarias para facilitar la integración de nuevas tecnologías de red y la conexión de recursos energéticos distribuidos de manera eficiente.

La tesis comienza con una revisión de la teoría económica que justifica la intervención regulatoria en el sector de la distribución de electricidad y sobre la que se fundamentan las prácticas regulatorias actuales. Asimismo, se proporciona una visión general de la evolución de las prácticas regulatorias en diferentes países a lo largo de las últimas décadas y se describen los nuevos desafíos a los que se enfrentas los operadores de las redes de distribución. Estos desafíos están principalmente ocasionados por la aparición de nuevos usuarios de estas redes, tales como generadores distribuidos o vehículos eléctricos, así como por los desarrollos tecnológicos.

A continuación, la tesis presenta una visión general de la metodología seguida para fijar los ingresos permitidos de las empresas de distribución así como las herramientas regulatorias comúnmente empleadas para este fin, haciendo especial hincapié en las técnicas de benchmarking regulatorio. A este respecto, la tesis incluye una nueva clasificación de los diferentes métodos existentes así como una discusión comparativa y exhaustiva sobre las ventajas e inconvenientes de los mismos.

Una vez finalizada esta revisión, se propone un marco regulatorio para fijar los ingresos permitidos de las empresas de distribución, adaptado al nuevo contexto marcado por la penetración de nuevas tecnologías y recursos energéticos distribuidos. El objetivo principal de dicha propuesta es proporcionar la estabilidad necesaria para atraer inversiones, minimizando la incertidumbre regulatoria e incentivando a los operadores de distribución a elaborar planes de inversión detallados y precisos. Con el fin de ilustrar la metodología propuesta, se define una estrategia de implantación de la misma en el contexto español, teniendo en cuenta la regulación y la situación actual del sector en este país.

Por último, se aborda el diseño de incentivos regulatorios asociados a la calidad de suministro y las pérdidas de energía en las redes de distribución. Primeramente, se hace un repaso del marco teórico que sirven de base para el diseño de estos incentivos y de los diferentes mecanismos empleados. A continuación, se enumeran y discuten en profundidad las principales dificultades existentes a la hora de llevar dicho mecanismos de incentivos a la práctica. Finalmente, se estudia cómo la aparición de nuevas tecnologías de red y la conexión de recursos energéticos distribuidos pueden afectar al diseño e implantación de estos incentivos.

Abstract

This thesis presents a review of the economic regulation of electricity distribution and proposes several recommendations to adapt current regulatory practices to facilitate the efficient integration of smart grid technologies and distributed energy resources.

The thesis starts with a review of the economic theory which justifies the regulatory intervention in the electricity distribution sector and which serves as the basis of current regulatory practices. Subsequently, an overview of the evolution of distribution regulation in several countries over the last decades is provided, after which the challenges faced by distribution system operators in the new environment are described. These challenges are mainly related to the connection of new types of distribution network users, such as distributed generators or electric vehicles, and technological developments.

Next, the thesis introduces the general methodology followed to set the allowed revenues of distribution companies, as well as the main regulatory tools used for these purposes. Particular emphasis is placed on regulatory benchmarking. The thesis proposes a new taxonomy for classifying the different benchmarking approaches and provides a comprehensive comparative discussion about the pros and cons of each approach.

After this review, a framework to determine the allowed revenues of distribution system operators suitable for the new context with smart grid technologies and distributed energy resources is proposed. The major goal of this proposal is to provide stability required to draw investments, whilst mitigating regulatory uncertainties and encouraging distribution companies to elaborate accurate investment plans. In order to illustrate the proposed approach, an implementation strategy for the Spanish context is defined, taking into account the specific conditions of in this country.

Finally, the thesis addresses the design of regulatory incentives related to quality of service and energy losses in distribution networks. Firstly, the theoretical framework that guides the design of these incentives and the different mechanisms used is reviewed. Thereinafter, the practical difficulties that can be encountered when implementing the aforementioned mechanisms are enumerated and discussed. Lastly, the thesis analyzes how the penetration of smart grid technologies and distributed energy resources can affect the design and implementation of these incentive schemes.

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Rafa

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Acronyms

ACCI	Average Customer Curtailment Index
AENS	Average Energy Not Supplied
AMI	Advanced Metering Infrastructure
AMM	Automated Meter Management
AMR	Automatic Meter Reading
ANM	Active Network Management
ASCI	Average System Curtailment Index
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
BAU	Business As Usual
BEV	Battery Electric Vehicle
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAPEX	Capital Expenditures
CAPM	Capital Asset Pricing Model
CEER	Council of European Energy Regulators
CH	Convex Hull
CHP	Combined Heat and Power
CI	Customers Interrupted per 100 customers
CMH	Convex Monotone Hull
CML	Customer Minutes Lost
CNE	Comisión Nacional de Energía (Spanish/Chilean energy regulator)
COLS	Corrected Ordinary Least Squares
CoS	Cost of Service
CPI-X	Consumer Price Index minus X (efficiency factor)
CRS	Constant Returns to Scale
CSV	Composite Scale Variable
DEA	Data Envelopment Analysis
DER	Distributed Energy Resources
DG	Distributed Generation
DMU	Decision Making Unit
DNO	Distribution Network Operator

DPCR	Distribution Price Control Review
DSM	Demand Side Management
DSO	Distribution System Operator
ECC	Energy Control Commission (Austrian energy regulator)
EHV	Extra High Voltage
ENP	Energy Not Produced or Energy Non-Produced
ENS	Energy Not Supplied or Energy Non-Supplied
ERGEG	European Regulators Group for Electricity and Gas
ERSE	Entidade Reguladora dos Serviços Energéticos
ESF	Economies of Scale Factor
ETS	(European) Emission Trading Scheme
EU	European Union
EV	Electric Vehicle
FDH	Free Disposable Hull
FIP	Feed-in Premium
FIT	Feed-in Tariff
GIS	Geographic Information System
GLS	Generalised Least Squares
GS	Guaranteed Standard
HV	High Voltage
ICT	Information and Communication Technologies
IFI	Innovation Funding Incentive
IPC	Índice de Precios al Consumo (CPI in Spain)
IPRI	Índice de Precios Industriales (Industrial price index in Spain)
IQI	Information Quality Incentive
KPI	Key Performance Indicator
LAD	Least Absolute Deviations
LAF	Loss Adjustment Factor
LCNF	Low Carbon Network Fund
LSDV	Least Squares Dummy Variable
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
$MAIFI_E$	Momentary Average Interruption Event Frequency Index
MFP	Multi-Factor Productivity
MH	Monotone Hull

MOLS	Modified Ordinary Least Squares
MQS	Minimum Quality Standard
MS	Member State
MV	Medium Voltage
NIEPI	Número de Interrupciones Equivalente de la Potencia instalada (Equivalent Number of Interruptions related to the Installed Capacity)
NIS	Network Information System
NPA	Network Performance Assessment
NPAM	Network Performance Assessment Model
NPV	Net Present Value
NRV	New Replacement Value
NST	Network Simulation Tool
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
OFFER	Office of Electricity Regulation
OFGAS	Office of Gas Supply
OFGEM	Office of the Gas and Electricity Markets
OLS	Ordinary Least Squares
OMS	Outage Management System
OPEX	Operational Expenditures
PEDS	Primary Elementary Distribution Systems
PES	Public Electricity Supplier
PEV	Plug-in Electric Vehicle
PFP	Partial Factor Productivity
PHEV	Plug-in Hybrid Electric Vehicle
RAB	Regulatory Asset Base
RAV	Regulatory Asset Value
RCMH	Ray-unbounded Convex Monotone Hull
RD	Royal Decree (Spanish regulatory document)
REC	Regional Electricity Company
RES	Renewable Energy Sources
RIIO	Revenues equal Incentives plus Innovation and Outputs
RNM	Reference Network Model
RODG	Reliability Options for Distributed Generation
RPI-X	Retail Price Index minus X (efficiency factor)

RPZ	Registered Power Zones
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control And Data Acquisition
SDEA	Stochastic Data Envelopment Analysis
SFA	Stochastic Frontier Analysis
SOTEX	Total Social Costs
TIEPI	Tiempo de Interrupción Equivalente de la Potencia Instalada (Equivalent Interruption Time related to the Installed Capacity)
TFP	Total Factor Productivity
ToU	Time-of-Use
TSO	Transmission System Operator
UK	United Kingdom
VAD	Valor Agregado de Distribución (Distribution Added Value)
V2G	Vehicle-to-Grid
VRS	Variable Returns to Scale
WACC	Weighted Average Cost of Capital
WTA	Willingness-To-Accept
WTP	Willingness-To-Pay

1. Introduction

Liberalization and privatization in the electric power sectors worldwide started over three decades ago. These reforms started in Chile in the early 80s, although the reforms took several years to be implemented; and it was not until the beginning of the 90s that the wave of deregulation started in Europe, being England and Wales the pioneers on this side of the Atlantic Ocean (Pollitt, 2005). Traditionally, electricity companies were vertically integrated utilities that were strongly regulated to prevent monopoly rents. However, the desire to introduce competition in the electricity sector brought about the need to unbundle the previously integrated utilities. As a result, electricity generation and retail were considered competitive activities, whereas transmission and distribution are still regulated as natural monopolies.

Electricity transmission is deemed essential to ensure appropriate competition at generation level; therefore it was the first activity to be unbundled and it is generally undertaken by entities independent from electric utilities. Concerning the remaining activities, it is possible to find countries or regions where vertically integrated utilities perform generation, distribution and retail. In others, the so-called distribution companies not only own and operate the distribution network, but also supply electricity to their customers. Finally, there are countries that have fully unbundled the four main activities comprising the electricity supply chain, as is the case of the European Union.

In such a context, electricity distribution is a regulated business carried out by distribution system operators (DSOs) who own and operate the distribution networks. Thus, the task of regulators is to determine the prices or revenues that DSOs can charge through network tariffs paid by end consumers so that DSOs can recoup their efficiently incurred costs. However, the existing asymmetries of information between DSOs and regulators make of this a challenging task for which several distinct approaches have been developed over the years. Nonetheless, distribution networks are nowadays witnessing profound changes related to the behaviour of distribution network users mainly caused by energy policy targets. These, together with technological changes, are driving profound changes in the way distribution networks have been conventionally planned and operated.

Consequently, the economic regulation of DSOs should be adapted to this new environment. This constitutes the main motivation of this thesis, which will be presented in more detail hereinafter. Thus, the remainder of this introductory chapter describes the motivation of the thesis, enumerates the objectives that are pursued and introduces the contents of subsequent chapters.

1.1. Background and motivation

1.1.1. Distribution networks and tasks of DSOs

Electricity distribution consists in transmitting energy from the extra high voltage (EHV) transmission grid down to end consumers. In order to do this, distribution networks are structured into subsequent voltage levels as shown in Figure 1-1. The subtransmission or high voltage (HV) network connects the transmission substations with the distribution substations and supplies some large industrial consumers. Due to their similarities with the transmission grid (meshed operation, highly monitored and controlled, dominated by overhead lines, covering large geographical areas), HV networks are actually operated by the same agent in some countries, i.e. the transmission system operator (TSO) (ERGEG, 2006). The most relevant measurement, protection and control devices are located at the distribution substations where the voltage is transformed into medium voltage (MV).

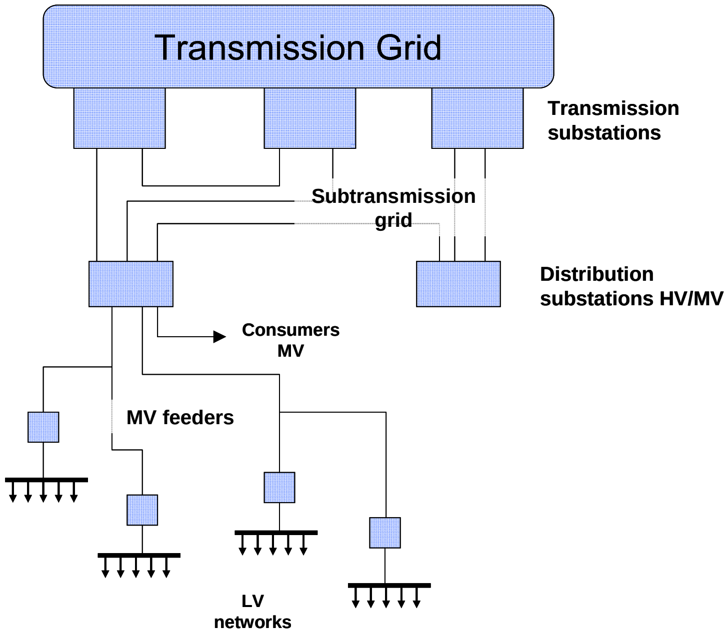

Figure 1-1: Structure of electricity distribution networks

The MV networks or primary distribution networks are found downstream of the distribution substations. These networks supply electricity to the transformer substations and medium sized consumers such as small industries, commercial customers or office buildings. As shown in Figure 1-2, the configuration of these networks can vary significantly between rural and urban areas. Urban MV grids are generally underground and even though they are built with a meshed structure to mitigate the consequences of power interruptions, they are operated in radial configuration so that network operation is simpler. On the other hand, rural MV networks are designed radial and built overhead due to the lower load density that can be found in rural zones.

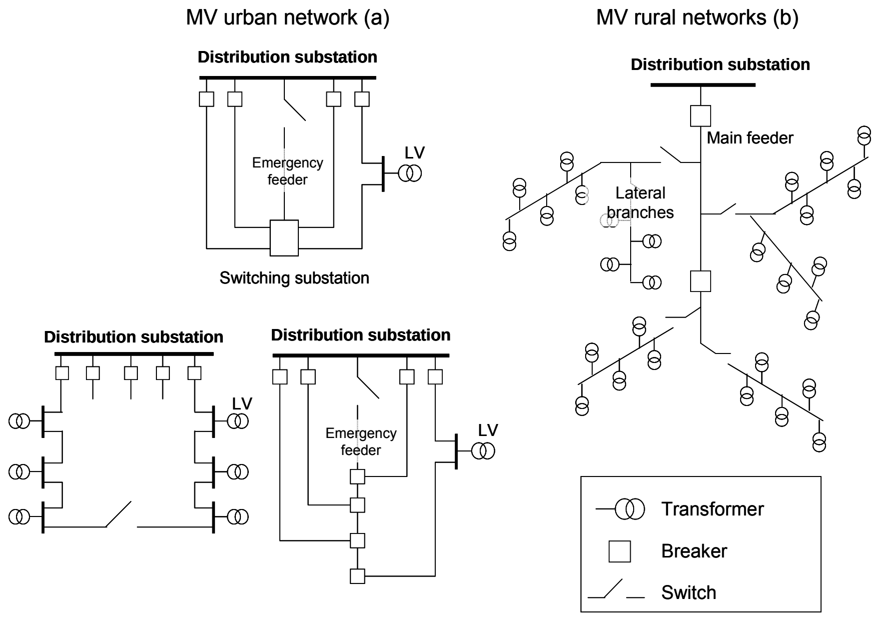

Figure 1-2: Typical configurations of MV distribution networks

The transformer substations incorporate some protection equipment as well as control devices, generally operated manually. Finally, low voltage (LV) grids arise from the MV/LV transformer substations as totally radial grids normally built underground or, in scarcely populated areas, on posts or on building walls. Small consumers such as residential consumers and small commercial places are normally connected to LV level. One of the major specific characteristics of distribution networks is that as one approaches lower voltage levels, the level of monitoring and controllability decreases whereas the number of individual network components and consumers connected grow significantly. For instance, in the year 2008 there were 2,643 HV consumers, whereas the MV and LV consumers were 54,862 and 23,702,180 respectively in Spain (CNE, 2009).

DSOs are the entities in charge of planning, operating and maintaining electricity distribution networks. Network planning essentially consists in determining what network components should be installed and when this should be done. In order to do this, DSOs must forecast the demand and new connections for a certain time horizon in the different regions where they operate. Decisions must be made in such a way that costs are minimized while complying with several constraints such as orography, undergrounding requirements, accessibility for maintenance purposes, voltage and capacity limits or quality of service requirements.

Distribution network operation requires performing several tasks. On the one hand, the back office is in charge of planning and carrying out maintenance tasks on network components as well as performing network analyses in order to ensure the subsequent safe and reliable grid operation. Maintenance works should be planned carefully in order to ensure network security while minimizing the effects on network users. On the other hand, control centres are in charge of the real-time network operation. The main tasks of control centres are to ensure that electrical magnitudes, such as voltages and power flows, remain at all times within acceptable limits, and to locate and repair the faults when they occur as well as restore power supply in the shortest time possible after a fault. This is achieved thanks to the SCADA (supervisory control and data acquisition) system which receives, processes and displays all the information sent by monitoring devices and delivers the orders sent by operators to telecontrolled devices. In addition to the SCADA system, control centres incorporate several software tools such a geographic information system (GIS), load forecasting, network information system (NIS), network reconfiguration tool or state estimator.

In addition to the network- related activities previously described, DSOs are usually responsible for providing metering and customer services as well. Metering activities, which are sometimes under the responsibility of suppliers or independent companies, entail deploying, maintaining, repairing and periodically reading all the meters located at consumers' premises. Moreover, customer services carried out by DSOs may include, among others, handling connection requirements, calculate network charges (unless done by the regulator) or dealing with contractual issues.

1.1.2. Costs and regulation

In order to undertake the previous tasks, DSOs have to incur in significant costs. Distribution network costs can be broadly classified into two categories, i.e. capital expenditures (CAPEX) and operational expenditures (OPEX).

CAPEX comprise those investments required to connect all network users to the grid, reinforce the grid to accommodate any growth in the demand of existing network users, as well as to replace aged assets. DSOs also incur in additional costs in order to comply with quality of service or environmental requirements such as energy losses reduction, improvement of continuity of supply or undergrounding in populated areas. The largest share of distribution network assets consists of lines and transformers. These investments generally have long useful lives of several years that can span up to 40 years. Moreover, DSOs need to install other equipment such as protection, control and measurement devices such as breakers, relays, switches, remote terminal units (RTU), etc. and communication systems. Lastly, distribution CAPEX include certain costs that are not proper network assets but which are necessary for DSOs to carry out their activities. Among these, one may find office buildings, computer hardware, vehicles, or small tools and equipment (OFGEM, 2007).

OPEX comprise a myriad of factors, some of which are related to the network activities such as asset maintenance (preventive or corrective) and repair. Furthermore, non-network related expenditures include personnel costs, building rentals, expenditures in innovation, business support costs, outsourcing, etc. Lastly, DSOs, as any other firm, has to pay for the corresponding taxes.

Under normal circumstances, any firm would recover the previous costs and its margin through the prices charged to their customers. However, as it will be shown throughout the thesis, electricity distribution is considered as a natural monopoly, thus deterring effective competition. Consequently, DSOs are regulated companies which are not allowed to set prices freely. Otherwise, an unregulated monopoly could charge prices much higher than actual costs thus resulting in economic inefficiencies (Joskow, 2005). Hence, regulators must define the prices or revenues that DSOs can collect from their customers. These revenues must be sufficient to allow DSOs to recoup their OPEX and make the necessary investments, including an adequate return on capital.

CAPEX remuneration comprises a term accounting for depreciation and a term that represents the return on investments. Depreciation (*D*) is computed according to gross assets and their useful lives, where the return on capital is calculated as the product of net assets[1] (gross assets minus depreciation) and a rate of return (*r*). Additionally, OPEX and taxes should be added to the previous components. Equation (1-1) illustrates the main remuneration components.

$$R = AB \cdot r + D + OPEX + Tax \tag{1-1}$$

The rate of return is frequently calculated as the weighted average cost of capital (WACC). This means that the final rate of return is obtained as the weighted sum of the cost of the different sources of financing used by DSOs, mainly debt and equity.

$$WACC = \frac{Debt}{Debt + Equity} \cdot r_{debt} + \frac{Equity}{Debt + Equity} \cdot r_{equity} \tag{1-2}$$

The WACC is a critical parameter in regulation, especially to determine the investment conditions faced by DSOs. The most controversial issue is generally how to compute the cost of equity. The most widely used method is the capital asset pricing model (CAPM), which determines the cost of capital as the sum of a risk-free rate plus a market risk premium according to the formula shown in (1-3) (Gómez, forthcoming).

$$r_{equity} = R_f + \beta \cdot \left(R_m - R_f\right) \tag{1-3}$$

[1] Net assets are also referred to as asset base (AB) of rate base.

Where:

R_f Risk-free rate, generally drawn from State bonds interest rate

β Parameter representing the volatility of the value of the company's shares compared to average market volatility

R_m Expected return on the market of an efficient portfolio

Besides ensuring the financial viability of DSOs, the regulator must protect the interests of consumers by encouraging low prices. Over the years, several distinct regulatory frameworks showing very different incentives to reduce costs have been implemented (Joskow, 2006). The evolution of the theory and practice of regulation will be presented in chapter 2 of this document, whereas the tools and incentive mechanisms which can be applied by regulators to induce efficiency gains will be reviewed in chapters 3 and 4.

Note that the most appropriate regulatory framework is not unique and may vary among regions or over time. Regulators often have to consider and ponder many factors such as the degree of unbundling (Nillesen and Pollitt, 2011), problems that may arise in developing countries (Rudnick et al., 2007), different ownership structure (Berry, 1994), resources limitations and political intervention (Glachant et al., 2012), regulation in surrounding countries (Haney and Pollitt, 2009), experience of the regulator (Haney and Pollitt, 2011), etc. Unless stated otherwise, the remainder of this document will be implicitly considering a situation similar to the European context, where DSOs are unbundled and seek the maximization of their profits, and independent regulators with adequate resources exist.

1.1.3. Motivation of the thesis

Traditionally, DSOs have planned and operated their networks assuming only passive consumers were connected to them, thus creating unidirectional and fairly predictable power flows from the upper to the lower voltage levels. Under this paradigm, network components were planned with sufficient spare capacity so as to accommodate the load growth expected over subsequent years. Hence, very low levels of network monitoring and control during the lifetime of these assets were required.

Nevertheless, this situation started to change when growing levels of distributed generation (DG) started to be connected to the distribution grid. This was mainly driven by environmental and security of supply concerns and supported by technological developments in the generation sector. For instance, directives promoting the production of electricity from renewable energy sources (RES) and combined heat and power (CHP) production or cogeneration were passed in the EU (European Communities, 2004; European Communities, 2009). In other countries, the installation of DG may be also driven by the operational benefits for electric utilities (where generation and distribution are not unbundled) (Dugan et al., 2001; Alarcon-Rodriguez et al., 2010) or to reduce the energy bill of end consumers (in case of net-metering) (Maribu et al., 2007; Darghouth et al., 2010).

Many different definitions of DG can be found (Ackermann et al., 2001; Pepermans et al., 2005). Notwithstanding, the most general one is the one provided in the EU electricity Directive which defines DG as "*generation plants connected to the distribution system*". This can be done either directly or through a consumption point meter. Under low penetration levels of DG, DSOs tend to connect these generators following conventional practices, also known as a *fit and forget* approach (Frias et al., 2009). Nonetheless, once

DG penetration is no longer negligible, power flow patterns can be significantly affected, thus requiring innovative network planning and operation practices.

Additionally, the promotion of energy efficiency together with the full liberalization and maturity level of retailing markets can cause profound changes in the behaviour of consumers. Demand side management (DSM) comprises energy conservation measures as well as all those actions aimed at modifying the electricity consumption patterns through economic and/or volume signals, i.e. demand response. Demand response is not at all a new concept as references to demand response measures dating back to the 60s can be found (Research Reports International, 2008). Nonetheless, the major challenge is to extend these load management actions down to small residential consumers, which would require extensive deployment of new technologies comprising smart meters, advanced metering infrastructure (AMI) or home automation as well as the design on the aforementioned economic and volume signals. Several of the most relevant drivers for demand response (reducing generation costs, mitigating CO_2 emissions or enhanced knowledge of consumers' behaviour) are not directly related to distribution networks; nonetheless, the impact on the activities of DSOs can be significant.

Furthermore, the same factors driving the adoption of DG have more recently brought about the need to electrify the transportation sector by means of the so-called electric vehicles (EVs). EVs partly or completely rely on electricity as a power source. Therefore, many of these vehicles need to connect to the electricity grid in order to charge the batteries that feed their electric motors. These are the plug-in EVs (PEVs), which can be either hybrid (PHEV) if they have a combustion engine in addition to the electric motor or purely electric, i.e. battery EVs (BEVs). PEVs would therefore need to connect to the distribution network in order to charge their batteries either at home, in public parking lots or in dedicated charging stations (Gómez et al., 2011). In spite of the low presence of PEVs nowadays, several studies have shown that the impact of EV charging on the distribution network can be significant (Clement-Nyns et al., 2010; Pieltain Fernandez et al., 2011).

Lastly, despite the fact that decentralized energy storage is still considered an immature technology, some stakeholders are already analyzing its potential impact on distribution grids (Eurelectric, 2012).

All these new types of distribution network users that modify conventional power flow patterns and can provide flexibility on the demand for distribution services (DG, active consumers, EVs, decentralized storage) are generically referred to as distributed energy resources (DER). The penetration of DER poses considerable technical and regulatory challenges at distribution level. In order to cope with these challenges, smarter distribution grids are deemed to be necessary (ERGEG, 2010; Eurelectric, 2011). Smart distribution grids are essentially characterized by a more intensive degree of network monitoring and control as well as the active participation of the users connected to it. However, achieving this change of paradigm in electricity distribution networks requires adapting conventional regulatory frameworks to drive the innovations and behavioural changes required from DSOs and network users. The focus of this thesis is placed specifically on how to regulate DSOs under this new context.

The main motivation of this thesis is therefore to analyze current approaches to the economic regulation of DSOs as well as the regulatory methods and processes so as to determine whether these are fit for purpose in the new environment and deliver amendments to adapt to the new situation or to foster the change.

1.2. Objectives of this thesis

Despite the fact the utility regulation and the regulation of electricity distribution has been analyzed both from a theoretical and practical viewpoints for many years, there are still several aspects that are not fully understood. Moreover, the upcoming changes faced by DSOs call for new regulatory approaches. Therefore, the core objective of this thesis can be enunciated as follows:

> **Revisit the main aspects related to the economic regulation of DSOs in order to identify weaknesses and best practices, considering the penetration of DER and smart grid technologies. This review will result in critical evaluations of alternative regulatory approaches and the proposal of several regulatory recommendations.**

The previous general objective can be broken down into the following specific objectives:

i. Perform a detailed review of the main theoretical and practical developments in the field of electricity distribution regulation and characterize the regulatory challenges posed by the penetration of DER and smart grid technologies.

ii. Identify and classify the main tools that regulators can use to deal with information asymmetries and promote efficiency and perform a critical evaluation to determine the most appropriate regulatory toolkit in an environment with smarter distribution grids and a significant presence of DER.

iii. Propose a framework for the regulation of DSO revenues that facilitates the transition towards smarter distribution grids and accounts for the effects of DER while promoting cost reductions.

iv. Analyze the impact of DER and smart grid technologies in the definition of regulatory incentives to improve continuity of supply and how regulatory approaches should be adapted accordingly.

v. Evaluate the effects of DER and smart grid technologies on energy losses and the associated regulatory incentives in order to determine how these should be modified to remain fit for purpose.

1.3. Outline and contents of the document

In order to address the previous objectives, this document is organised into nine chapters. Besides this introductory chapter, the thesis comprises 7 self-contained chapters that, in principle, could be read independently (chapters 2, 3, 4, 5, 6, 7 and 8). Each one of these chapters includes specific conclusions as well as their own reference list. Chapters 2-4 mostly contain critical literature reviews and summaries of the state of the art, whereas chapters 5-8 focus on the specific analyses and regulatory proposals that constitute the core contributions of this thesis. Finally, Chapter 9 presents the major conclusions drawn from the work presented in the previous chapters.

Chapter 2 analyzes why electricity distribution is considered as a natural monopoly and why it is necessary to regulate electricity distribution companies. A review of the theoretical developments in the field of utility regulation is presented. Moreover, this chapter describes how electricity distribution companies have been actually regulated worldwide and identifies the major lessons learnt over the years. Finally, the changes foreseen for the distribution sector over the coming years as well as the impact on regulation are described in detail.

Chapter 3 presents a general description of how incentive regulation is applied nowadays to regulate electricity DSOs. Moreover, the major tools that are used by energy regulators to overcome the existing asymmetries of information and encourage DSOs to efficiently reduce costs are identified. The contents of this chapter represent the starting point from which subsequent analyses and regulatory proposals will be developed.

Chapter 4 is specifically devoted to regulatory benchmarking, which can be defined as the quantification of certain variables, typically related to costs or performance, which allow comparing the behaviour of regulated firms among them or with a theoretical efficient firm. Benchmarking constitutes the major instrument to tackle information asymmetries. An in-depth review of all the possible methods of regulatory benchmarking that can be applied to electricity distribution is made, which results in the proposal of a novel and more comprehensive taxonomy of benchmarking approaches.

Chapter 5 focuses on the regulation of allowed revenues of DSOs by performing a detailed analysis of all the issues that should be considered by a regulator in any price review process: determination of the asset base, remuneration formula, annual revenue updates, ex-post corrections, etc. Several proposals are made so as to ensure that DSOs are encouraged to reduce costs by means of efficiency gains, whilst providing a transparent and stable framework to invest in new technologies. These are essential characteristics in order to attain an effective and efficient integration of DER and smart grid technologies. With the aim of illustrating how these proposals could be implemented, the Spanish context is used as a case study. Hence, a critical evaluation of the current Spanish regulation is made and some recommendations to amend the weaknesses identified are made based on the aforementioned general proposals.

Chapter 6 builds on the previous review of the different benchmarking methods and performs a critical assessment of the pros and cons of the main existing methods. Particular attention is paid to the new challenges caused by the penetration of DER and smart grid technologies. The conclusions from this chapter intend to serve as guidelines for carrying out efficiency assessments in smarter distribution networks with high levels of DER.

Chapter 7 pays attention to quality of service in electricity distribution, which is an essential aspect of utility regulation. More specifically, the chapter assesses how DSOs can be encouraged to consider continuity of supply. Thus, a review of the theoretical background on which continuity regulation is based upon is made. However, the implementation of theoretical guidelines is not straightforward due to several practical difficulties that are also analyzed in this chapter. Next, the effects of smart grid technologies on the definition of regulatory incentives for continuity of supply are described and illustrated through two test distribution feeders. Thus, the impact on different types of distribution networks can be evaluated. Finally, it is discussed whether regulatory incentives for continuity of supply should start taking into account the presence of new network users, in this case DG, and how this can be done. Numerical examples are used to support the discussions.

Chapter 8 follows a very similar structure as the previous one, albeit addressing energy losses regulation. Energy losses inevitably occur when electricity flows through the distribution network. However, DSOs can implement certain measures to reduce them, thus saving power system costs and CO_2 emissions. Consequently, regulatory incentives to reduce energy losses are frequently used in electricity distribution. Therefore, this chapter describes the regulatory approaches that can be found and the actions that DSOs can take to reduce them. The connection of DER can significantly modify power flows and energy losses in distribution networks. Moreover, smart grid technologies may offer DSOs new alternatives to deal with energy losses. All these issues will be analyzed in this chapter in order to clarify how regulatory incentives should be set in this new context.

Chapter 9 is the final chapter of the thesis dissertation which summarizes the main conclusions drawn from the thesis developments together with the major original contributions. Additionally, potential lines for future research are identified.

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2. Economic regulation of electricity distribution: rationale, evolution, current situation and challenges ahead

Electricity distribution is widely considered to be a natural monopoly. Hence, it has remained as a regulated activity after the liberalization that has been introduced in the power sector in many countries over the last decades. Therefore, regulatory bodies have had to regulate distribution companies in terms of costs, entry and other related aspects.

The approaches to the economic regulation of electricity distribution have evolved over time in response to advances in the field of theory of regulation and the practical experiences gathered. Cost-of-service regulation, which aimed at providing a *fair* rate of return on investments, is the more conventional type of regulation. However, as it will be discussed in this chapter, this kind of regulation is believed to potentially lead to inefficient outcomes. Consequently, different types of incentive regulation have been increasingly adopted in order to encourage cost reductions through gains in efficiency.

However, distribution networks are nowadays facing times of rapid changes deriving from technological developments and the connection of new types of users to the grid. The new challenges posed by the smart grids and the connection of distributed energy resources (DER) question the suitability of conventional regulatory practices and may render current regulatory schemes ineffective. Thus, new approaches to regulation could be necessary.

The remainder of this chapter starts by reviewing the characteristics of natural monopolies and whether electricity distribution fits into this category (Section 2.1). Then, the chapter will address the question about how to regulate natural monopolies (Section 2.2). Next, the chapter will turn the focus to the regulation of electricity distribution (Section 2.3), paying special attention to the main regulatory implications of the advent of smart grids and the large-scale connection of DER (Section 2.4). In this regard, particular emphasis will be placed on DG, as it is one of the major drivers of the change, at least in a European context (Meeus et al., 2010; Eurelectric, 2011). Finally, section 2.5 presents some concluding remarks.

2.1 Why is the economic regulation of electricity distribution needed?

Over the last quarter of the 20th century, liberalisation and restructuring were introduced in several sectors worldwide. Activities that were previously heavily regulated, such as air transport, railway transport or petroleum production, were liberalised and market competition was introduced. Regulation remained for those aspects where market forces were deemed insufficient to bring a desirable outcome. These aspects include quality of service, environmental impact, antitrust problems or the protection of vulnerable consumers.

The wave of deregulation reached the electricity sector. A necessary step in the liberalisation of this sector was the unbundling of vertically integrated monopolies into different activities. Broadly speaking, four main activities within the electricity supply chain can be distinguished: generation, transmission, distribution and supply. It is commonly accepted that generation and supply can be liberalised and carried out under competitive schemes. The presently running wholesale and retail electricity markets across the world are proof of this[2]. However, transmission and distribution are generally considered natural monopolies, thus remaining as regulated businesses. On the ensuing, the main features that characterise a natural monopoly are briefly enumerated, followed by a literature review about whether electricity distribution fits under this denomination.

Definition of natural monopoly and the need for regulation

The most immediate definition of natural monopoly, or technological definition (Joskow, 2005), is any industry in which it is less costly for a single firm to supply the demand than for multiple firms. The cost functions of firms operating in this industry would thus be subadditive. When this condition holds true for the whole range of demand for the product supplied, it is said that there exists global subadditivity of costs. Furthermore, the existence of economies of scale (declining average costs with output) over a range of output sufficiently large to meet the demand is a sufficient condition for the existence of cost subadditivity. Being this the case, it will also happen that marginal costs are lower than average costs.

However, the existence of a market supplied by a single firm (or few of them), or the fact that this is the least-cost market outcome, does not necessarily imply that a regulatory intervention is needed to avoid monopoly rents (Baumol, 1982). The reason for this is that in a (perfectly) contestable market, i.e. "*one into which entry is absolutely free, and exit is absolutely costless"* (Baumol, 1982), firms in the market would be deterred from charging monopolistic prices due to the threat of potential new entrants. Nevertheless, in practice markets can present significant barriers of entry. The existence of sunk costs probably constitutes the most relevant barrier of entry. This is particularly important in the presence of (long-lived) fixed sunk costs and when these costs amount to a large fraction of total costs incurred (Kahn, 1988).

Summing up, it can be concluded that a natural monopoly is likely to arise when an activity presents significant economies of scale and a significant amount of sunk costs are involved. Additionally, some authors have pointed out several attributes that denote the existence of a natural monopoly, which are to some extent related to different barriers of entry and exit. These comprise the following: the product or service cannot be stored, the product or service is essential, high proportion of fixed to variable costs, the producer has a favourable location or there are network effects, the product or service supplied by two firms are close substitutes and there are increased costs as a result of duplicating facilities (Joskow, 2005).

According to the economic theory, regulation is needed to prevent monopolistic firms from earning monopoly rents at the expense of the consumer surplus. Nonetheless, some authors questioned the need for regulation as they argue that governance failure (or regulatory costs) may surpass market failures (Posner, 1999)[3]. Therefore, the costs of "imperfect markets" should be balanced against the costs of "imperfect regulation" (Joskow, 2010). Moreover, it is possible to attain competitive outcomes even in the event of a single-firm market by means of competition for the market, as opposed to competition in the market (Demsetz, 1968).

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[2] Notwithstanding, it is true that numerous regulatory interventions can be found in these markets to correct existing market imperfections, e.g. capacity payments, subsidies for renewable energies, price caps, regulated tariffs (last-resort tariffs), etc.

[3] The author concludes that *"The benefits of regulation are dubious, not only because the evils of natural monopoly are exaggerated but also because the effectiveness of regulation in controlling them is highly questionable".*

The flow chart shown in Figure 2-1 summarises the conceptual questions that need to be answered in order to determine whether economic regulation of a certain sector is required. It can be seen that three main queries arise. These will be sequentially addressed throughout the remainder of this section. It should be noted that the questions arising from each one of the ending nodes, such as which is the most appropriate kind of regulation or how to design the auctions, fall outside the scope of the current discussion.

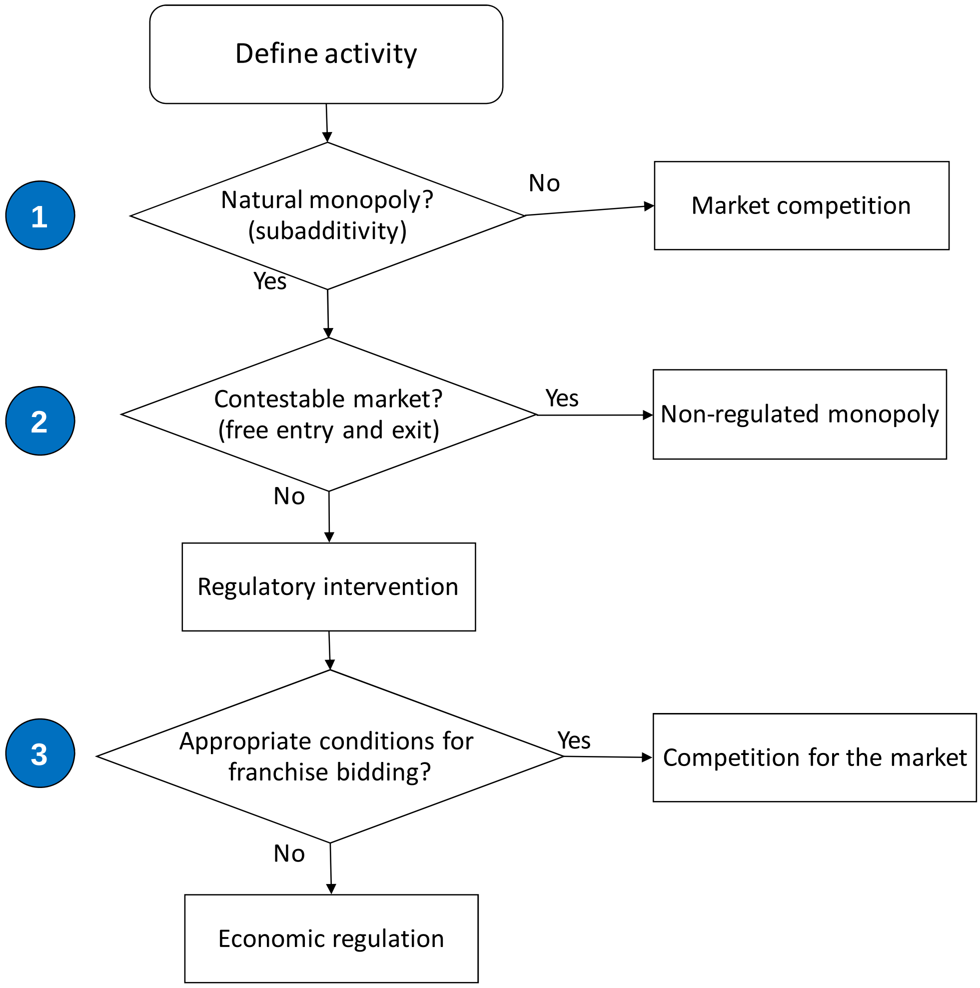

Figure 2-1: Flow diagram for a simplified test for natural monopolies

1. Electricity distribution as a natural monopoly

The previous discussion brings us to the first relevant question: is electricity distribution a natural monopoly?

Electricity distribution, as defined above, complies with some of the characteristics of natural monopolies: network effects, large share of fixed costs, essential service[4], non-storable product or the fact that duplicating facilities would lead to higher costs[5]. However, empirical studies examining this issue are not plentiful. Notwithstanding,

[4] Note that in the case of electricity distribution, electricity itself is not the product provided. This would be the access to a supply of electricity with a certain level of quality for consumers, or the possibility to sell their production for DG units.

[5] Note that inefficiencies would arise when two distribution companies duplicate facilities to supply the same consumers (parallel networks). Nevertheless, this does not imply that there should be a single DSO within a country, as several DSOs could be efficiently supplying different geographical areas within the same country.

several authors have tried to answer these questions since liberalization processes started in the 80s. Different approaches can be found in the literature to address this question.

In some publications, econometrics is applied to estimate the cost function of electricity distribution utilities[6]. The properties of this cost function are later examined so as to determine whether it complies with the attributes of natural monopolies[7], i.e. cost subadditivity, economies of scale, etc. Within this category, one may find the following references:

- (Salvanes and Tjøtta, 1998) estimate a translog cost function for 91 Norwegian distribution utilities. In subsequent analysis, the authors test whether the cost function is subadditive by comparing the level of total costs that would be incurred by a single firm or by two firms providing the same level of output. Results show that the obtained cost function is indeed subadditive in costs and that electricity distribution would thus show properties of a natural monopoly. It is important to remark that the distribution companies considered carried out retailing activities as well. However, the authors argue that the monopolistic characteristic is most likely to derive from the network-related activities.
- (Filippini, 1998) uses a sample of 39 Swiss electricity distribution utilities (acting as well as suppliers) to compute a translog cost function. In order to verify whether distribution is a natural monopoly, the author tests for the existence of economies of density and economies of scale. The results show that economies of output, economies of consumer density and economies of scale are present for most levels of output. This allows the author to conclude that electricity distribution seems to be indeed a natural monopoly.
- (Kwoka, 2006) estimates a quadratic cost function with data from 500 US distribution utilities. As in previous publications, the distribution firms included in the sample act as retailers too. Some of the distribution utilities considered in this paper are regulated (supposedly under a cost-of-service regulation), whereas others are in competition among them, either through direct competition[8] or through benchmarking (which according to the author would correspond to some sort of yardstick regulation)[9]. This allows the author to compare the results of different regulatory approaches through the use of a dummy variable. The conclusions are that direct competition leads to costs reductions even in the presence of some economies of scale. Nonetheless, benchmark competition could be a powerful substitute for direct competition as it also leads to cost reductions and does not sacrifice scale economies.

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[6] Publications analysing vertically integrated electricity companies, such as Roberts, M. J. (1986). "Economies of Density and Size in the Production and Delivery of Electric Power." Land Economics **62**(4): 378. will not be discussed in detail.

[7] Other authors have attempted to estimate different variants of cost function of electricity distribution companies with a different purpose. Their main goal was to assess whether distribution companies were operating at optimal scale and whether mergers could take advantage of economies of scale. See Yatchew, A. (2000). "Scale Economies in Electricity Distribution: A Semiparametric Analysis." Journal of Applied Econometrics **15**(2): 187 for an overview.

[8] Some of the companies under direct competition compete only to supply new consumers, whereas others do it both for new and existing consumers, who would be free to switch between companies. As a consequence, some of these companies have duplicated facilities or even share poles and wires with neighbouring distribution firms.

[9] The concepts of cost-of-service and yardstick regulation will be explained in subsequent sections.

Mathematical programming techniques have also been used to assess the existence of cost subadditivity in electricity distribution. In (Agrell and Bogetoft, 2007), the authors apply the methodology presented in (Bogetoft and Wang, 2005) originally intended to quantify the potential gains from mergers. This methodology is based on the estimation of the potential efficiency gains of several firms operating separately against the potential gains of merged companies with a data envelopment analysis (DEA) model. (Agrell and Bogetoft, 2007) apply this methodology to quantify separately the potential efficiency gains of three DSOs operating the HV, MV and LV levels separately (breaking down all the inputs and outputs accordingly) against a DSO jointly operating all three voltage levels. Results are computed for a sample of 328 German DSOs and show that substantial subadditivity exists in electricity distribution.

Lastly, some authors perform qualitative studies as a result of empirical observations that open the discussion of whether the economic regulation of electricity distribution is needed.

- (Gunn and Sharp, 1999) observed that some distribution companies in New Zealand were competing to provide their distribution services to new consumers after the franchise areas were removed to stimulate competition in the retailing activity (which was still carried out within the same company on separate accounts). A simplified mathematical model mimicking the pricing behaviour of a distribution company (only the network business) is developed. The authors conclude that this competition is taking place due to unintended consequences of a light-handed regulatory regime and that this competitive behaviour among firms may yield inefficient results.
- (Saplacan, 2008) argues that electricity distribution could be seen as a twofold activity, composed of network ownership and planning, on the one hand, and a network operation on the other hand. Moreover, it is suggested that whilst network ownership is indeed a natural monopoly, some activities related to grid operation may be subject to competition for the market. This is illustrated with some practical examples from the distribution sectors in France and the UK, and from the transportation sector. Nonetheless, the author acknowledges that this would be a challenging task since it is difficult to properly identify the different *packages* in which to divide grid operation given the important interdependencies among them. Therefore, it is concluded that regulators should at least try to identify the different *packages* and allocate costs to each one of them when assessing the efficiency of distribution companies.

Overall, previous publications, both applying quantitative or qualitative methods, tend to conclude that electricity distribution is in fact a natural monopoly, or at least it presents some characteristics proper to natural monopolies. However, there seems not to be sound empirical evidences proving that the cost of free competition in the market would exceed that of regulation or vice versa. This is presumably due to the lack of actual cases of competition in the market to be analysed. Notwithstanding, in those regions where competition in the market has actually taken place, it is suspected of leading to inefficient results (Gunn and Sharp, 1999) or seems to take place due to the fact that distribution was integrated with retailing (Kwoka, 2006).

(Saplacan, 2008) argues that electricity distribution, more specifically network operation, could be subject to competition based on some observations from the functioning of actual firms. Nonetheless, in case some parts of distribution network operation could be subject to competition, this would merely imply that some costs be excluded from the

DSO price control, as these would be carried out by different agents (e.g. metering), or alternatively that DSOs would directly outsource these services should this be less costly for them. Regardless of this, regulating network investments and controlling the quality of service delivered by the grid operator will still be needed in any case.

Moreover, implementing efficiency assessments differentiating among different packages, as proposed by (Saplacan, 2008), could create separate incentives for OPEX and CAPEX thus neglecting possible trade-offs between different types of costs (Jamasb and Pollitt, 2007). The transition towards smart grids and the integration of DER in network operation will increase the importance of these tradeoffs as OPEX solutions could become interesting alternatives to CAPEX solutions. For instance, DG or demand response could be used to defer network investments or contribute to handling congestions or contingencies in distribution networks (Belhomme et al., 2009; Trebolle et al., 2010; Wang et al., 2010). Consequently, separating the distribution network operation from the ownership could result in higher rates for consumers.

2. Contestability in electricity distribution

The issue of contestability in electricity distribution has not been addressed in the literature. Notwithstanding, it seems clear that the intrinsic characteristics of electricity distribution create significant barriers of entry and exit. The need to incur in high investments, which may be seen as sunk costs, and the fact that no alternatives to the distribution network is available make this sector highly non-contestable. The relevance of the latter issue can be illustrated with an example taken from the Spanish energy sector.

CLH (Compañía Logística de Hidrocarburos) is the main distributor of liquid fuels and petroleum products in Spain. This company provides services related to storage, distribution in tankers, pipelines, ships, etc., and logistics solutions. CLH also provides some other value added services such as analysis and control of products, maintenance services for petrol stations, control of fuel additives, etc. This is an activity that shows cost subadditivity given that the integrated operation of storage and transport of fuels at national level allows reducing operating costs and increases the geographical access of all operators. However the regulatory intervention is limited to some restrictions on the shareholders. Operators with petrol refining installations cannot own more than 45% altogether and each individual shareholder cannot surpass 25%.

The organisation of the sector resembles a light-handed or self-regulation approach as no further restrictions are placed on prices or revenues. CLH ensures transparent and non-discriminatory access to all the operators by charging published prices which are equal to all suppliers regardless of the volume contracted. Annual price updates linked to the RPI and efficiency gains are made by CLH itself. Despite the fact that pipelines require indeed significant investments, the existence of alternative transportation means such as trains or tankers prevent CLH from charging abusive prices. In that case, alternative operators could enter the market providing similar services. Therefore, the activities of CLH can be considered as contestable, thus allowing for self-regulation.

3. Franchise bidding in electricity distribution

This leads to the conclusion that regulatory intervention would be needed in the electricity distribution sector. Nevertheless, even if we accept that the regulatory intervention is needed; economic regulation is not necessarily the immediate solution since auction mechanisms could be used instead of utility economic regulation.

(Littlechild, 2002) discusses the possibility of competition for the market in electricity distribution through long-term contracts awarded by means of competitive bidding. For these purposes, the paper analyses the existing agreement between Seeboard Powerlink and the London Underground Company to plan and maintain the underground distribution network[10]. The adopted solution, based on a long-term contract (30-year long), is compared against potential alternatives; namely public ownership, short-term contracts or different forms of utility regulation. The paper concludes that both franchise bidding and utility regulation have their merits and that no *per se* superiority of one mechanism over the other exists.

According to (Littlechild, 2002), electricity distribution is usually excluded from the activities that could be subject to franchise bidding. The author states that (Domberger, 1986) is one of the few exceptions. Furthermore, this latter reference identified several conditions under which franchise bidding might be easier to implement: "*technology of production is relatively simple and static, the product or service can be specified with precision and significant demand fluctuations seem unlikely*"[11]. Electricity distribution is explicitly mentioned as a business that fulfils these conditions. Therefore, (Littlechild, 2002) concludes that electricity distribution could be subject to franchise bidding given that it complies with the conditions stated in (Williamson, 1976; Domberger, 1986).

However, the author seems to neglect the ongoing changes in the sector related to the adoption of smart grids and the connection of DER which may cause significant deviation from these conditions. The new situation and its regulatory implications will be detailed in Section 2.4. Notwithstanding, it can be briefly summarised by stating that the distribution companies will presumably have to adopt new technologies and provide their services to new and changing types of customers. These will inevitable affect the way distribution network are planned and operated.

This new environment could not be envisioned at the time (Domberger, 1986) enunciated the desirable conditions for franchise bidding to be implemented and stated that electricity distribution complied with them. Furthermore, (Littlechild, 2002) did not consider the forthcoming changes presumably because in the early 2000's the discussion about smart grids was, at most, incipient. Additionally, the implementation of franchise bidding in electricity distribution could be hampered by some of its intrinsic characteristics such as the existence of long-lived investments and asymmetries of information (Joskow, 2005). Therefore, electricity distribution does not seem to be a proper candidate for a franchise bidding competition (as alternative to economic regulation) due to the following reasons:

- **Definition of the service and consumer preferences:** franchise bidding requires a precise definition of the service supplied (Domberger, 1986) and the consumers' preferences (Williamson, 1976). This used to be relatively true for electricity distribution, although the evolution to a more sustainable electricity system will probably modify this paradigm (Shaw et al., 2010; CEER, 2011a). In order to manage the presence of a large number of small DER, DSOs will probably engage in innovative contractual agreements with new agents such as aggregators or microgrid operators. Moreover, their role in the deployment of metering and EV recharging infrastructures or the implementation of demand response programmes

[10] Note that this is a very particular type of distribution network which does not face the same conditions as conventional electricity distribution grids. Additionally, the grid owner's primary activity is different to that of operating and maintaining the electricity grid. Nonetheless, some of the conclusions drawn may be relevant to the topic discussed in this thesis.

[11] This is included at footnote 55 in (Littlechild, 2002)

is still to be accurately defined (Gómez et al., 2011; Meeus and Saguan, 2011). Additionally, DSOs will presumably be asked to deliver new outputs answering the needs of network users such as enhanced quality of service, new terms of grid connection or the adoption of a more active role in delivering a sustainable electricity supply (OFGEM, 2010).

- **Technology:** (Domberger, 1986) includes electricity distribution among the sectors where technology is well developed and static, thus presenting appropriate characteristics for franchise bidding. However, smarter distribution grids require the deployment of new technologies, some of which are still being developed, such as advanced metering infrastructure, feeder automation, substation automation or communications (EPRI, 2011). Despite the fact that several studies have been carried out, there are still high uncertainties about what the costs and benefits of the smart grid technologies will be (ERGEG, 2010; Joskow, 2011). Therefore, electricity distribution can hardly be considered nowadays as a sector where technology is static and developed.
- **Demand:** a stable demand without significant fluctuations is another prerequisite to introduce competition for the market. Traditionally, DSOs merely had to forecast the expected growth in demand of existing consumers as well as accommodate new consumers that asked for connection. Thus, the overall demand to be supplied by distribution networks used to be fairly predictable. Nonetheless, demand response and EV charging will substantially modify conventional consumption profiles and even offer DSOs the possibility to modulate it according to network needs. Additionally, the large-scale connection of intermittent or non-controllable DG to the distribution network will increase the unpredictability of overall net demand. This last issue is particularly relevant in systems where generation is unbundled from distribution and DSOs have no direct control over DG production. Furthermore, foreseeing the point of connection of new network users will become more complicated as DG and EVs are not as predictable as consumers.
- **Long-lived investments:** electricity distribution is characterised by a large proportion of (immobile) sunk costs corresponding to network assets. Under these conditions, franchise contracts are very difficult to apply as they could create inefficient investment incentives and induce opportunistic behaviour, especially when short-term contracts are implemented (Joskow, 2005). (Littlechild, 2002; Saplacan, 2008) describe several examples of DSOs that contract out or externalise certain services to external companies, particularly those related to network maintenance and construction. In fact, in the future, it is expected that DSOs contract more services from the flexible DER or their representatives (aggregators, microgrid operators). However, these are all short-term contracts and in none of these cases the ownership of the assets or the control over the firm changed hands. On the other hand, in the Panamanian case described below, the ownership indeed changed and long-term contracts were signed (15 years). Nevertheless, the tender winners were still subject to a revenue cap regulation.
- **Asymmetries of information:** the existence of asymmetrical information between the incumbent and new bidders represents a hurdle to renegotiate the contract after its expiration. The incumbent will always be in a privileged position should it want to retain the franchise contract. This is what Williamson named "*lack of bidding parity during contract renewal*" (Williamson, 1976). Existing experiences

do not seem to have found any solution for this, besides measures to ensure a smooth transition in case the incumbent is willing to drop out by setting clauses relative to assets, staff, etc. (Littlechild, 2002).

Notwithstanding, besides the aforementioned example of the contract between London Underground Ltd and Seeboard Powerlink, tendering processes have been implemented in some countries in order to issue electricity distribution licenses. For example in Panama, the control of no less than 51% of the shares of electricity distribution companies is sold through a tendering process every 15 years to national or foreign bidders (ASEP, 1997). The former owners have to determine the value of their shares and will retain ownership if no other offer surpasses this value.

Nevertheless, Panamanian distribution companies are regulated anyway under a revenue cap formula according to the methodology defined for the period 2010-2014 in (ASEP, 2010). The beginning of each regulatory period is completely decoupled from the tendering process. Therefore, this process should not be seen as a proper regulation for the market as an alternative to economic regulation. The main objective of these tenders is not to implement a competition for the market, but to offer the owners of the distribution companies the chance to sell the company after a certain number of years. The gains from this lengthy process for consumers are not fully clear since it implies substantial consultancy costs to determine the value of the company and the amount paid by the new purchasers is given entirely to the former owners. Consequently, franchise bidding may be implemented in electricity distribution, but it may not be seen as a substitute for economic regulation.

Conclusions:

Summing up, it has been shown that existing studies have concluded that there are serious reasons why electricity distribution should be considered a natural monopoly. Moreover, electricity distribution is necessarily a very capital intensive business without a clear alternative for consumers. This creates significant barriers of entry and exit, making it a non-contestable activity. Additionally, the possibility to introduce competition for the market, at least for some parts of the activity, has been discussed. However, important difficulties that could seriously hamper the implementation of such a mechanism have been identified. Some of these difficulties are due to the intrinsic characteristics of electricity distribution, namely the existence of a large proportion of sunk costs and asymmetries of information, whereas others are a result of the ongoing changes in the electricity sector. The large-scale connection of DER and the implementation of smarter distribution grids will modify the role of DSOs, require the deployment of innovative technologies and solutions and introduce high uncertainties in the demand served by distribution networks. Consequently, it can be concluded that electricity distribution companies ought to remain subject to economic regulation, in spite of being able to contract out specific services.

2.2 Regulating natural monopolies

The previous section concluded that electricity distribution is a natural monopoly and should be subject to some kind of economic regulation. Thus, the next question requiring an answer would be how these firms should be regulated. The literature dealing with the theory of the economic regulation of natural monopolies is extensive and has significantly evolved over time. Hereinafter, an overview of the evolution of the theoretical developments on this subject will be presented. Figure 2-2 shows a simplified summary of this review at the end of the section.

Perfectly informed regulator:

The traditional theory of regulation assumes that the regulator is perfectly informed and that firms cost functions are fully known and efficient (Joskow, 2005). Thus, firms are considered not to incur in productive inefficiency or X-inefficiency (Leibenstein, 1966). In this context, the focus used to be placed on pricing the services so as to attain an optimal allocative efficiency, i.e. maximise total surplus, subject to a break-even or participation constraint of the regulated firms.

Marginal pricing (first-best solution) in natural monopolies would fail to satisfy the break-even constraint owing to the fact that marginal prices fall below average prices. Therefore, a certain markup on the marginal cost would be necessary to ensure the viability of regulated firms. The second-best solution, which maximises total surplus while meeting the break-even constraint, was found to be distributing the markup proportionally to the inverse of the elasticity of demand of each group of consumers or the demand for each product (in a multi-product context). This is known as Ramsey pricing or Ramsey-Boiteux pricing (Ramsey, 1927; Boiteux, 1956). More advanced forms of (non-linear) pricing were subsequently developed (Joskow, 2005).

Cost-of-service regulation:

However, in practice regulators have to face significant asymmetries of information. Moreover, actual regulatory processes typically consist of two stages: first the total firms' revenue requirements are determined and, second, tariffs are designed so as to collect the previous costs[12]. The previous theoretical developments had focused mostly on this second component as a perfectly informed regulator was generally assumed. Nevertheless, the first stage proved to be at least as important as an appropriate tariff design. In order to tackle this problem, regulatory accounting systems were developed. The aim of regulatory accounting is to gather data from the regulated firms regarding their costs, performance indicators and other information that could be useful in regulatory processes.

This resulted in the implementation of cost-of-service regulation. A *pure* cost-of-service regulation consists of letting the firms recover all the costs they have incurred including a *fair* return on the investments they have made. This is why this regulatory approach is sometimes referred to as rate-of-return or cost-plus regulation.

Note that in the previous paragraph, two adjectives have been deliberately written in italics. This is because the key aspects concerning cost-of-service regulation are behind them.

- *Fair* rate of return:

Setting the allowed rate of return in practice is a challenging task. This should be such that it attracts the required level of investments but not as high as to exceed this level and make consumers pay more than needed.

(Averch and Johnson, 1962) developed a model that illustrated that a regulated firm under a constraint on the rate of return would not minimise its costs. If the allowed rate of return exceeds the cost of capital, firms would tend to substitute labour inputs for capital inputs

[12] From this point on, the emphasis will be placed on the revenue requirements determination.

in order to maximise their profits. In practice, this means that if the rate of return is too generous, regulated companies would tend to over-invest. This is known as the Averch-Johnson effect, also known as the Averch-Jonhson-Wellisz effect (Kahn, 1988). In the years following Averch and Johnson's paper, several authors analysed deeper this effect (e.g. (Baumol and Klevorick, 1970)) and researched into empirical evidences of this effect; see (Leon, 1974; Spann, 1974) for studies on electric utilities. Additionally, some authors tried to determine how regulators should determine this rate of return so as to avoid the consequences of the Averch-Jonhson effect (Klevorick, 1971; Leland, 1974).

The Averch-Johnson effect is frequently mentioned as one of the major drawbacks of cost-of-service regulation. However, the empirical evidences for the existence of the Averch-Johnson effect in practice are not definite (Joskow, 2005). Furthermore, (Joskow, 2005) states that the kind of inefficiency highlighted by Averch and Johnson, i.e. inefficient ratio of capital to labour inputs, differs with the actual concerns of regulators, which is to encourage firms to reduce the costs of production, i.e. reduce the X-inefficiency. Therefore, the real drivers to abandon cost-of-service regulation would lie in the lack of incentives to spend managerial efforts in reducing costs.

– *Pure* cost-of service regulation:

The description of a *pure* cost-of-service regulation above is subject to two implicit assumptions: i) the regulator does not scrutinise the costs reported by the firms and ii) the prices are adjusted on a continuous basis to match revenues and costs. However, these assumptions do not reflect actual regulatory practices for several reasons. On the one hand, regulators could remove some incurred costs from the allowed revenues in case they were deemed inefficient. On the other hand, prices were not reviewed continuously to reflect the actual costs. Consequently, a certain lag between costs and revenues generally existed. This regulatory lag created some incentives for the firms to reduce their costs as prices would not be updated for a number of years.

Incentive regulation:

The attempts at overcoming the lack of incentives to reduce costs deriving from cost-of-service regulation resulted in different types of incentive regulation, either formalised or not. Note that herein incentive regulation will be understood as any remuneration system designed with the goal of encouraging regulated firms to be more efficient, i.e. reduce their X-inefficiency through managerial effort.

A review of the literature on the application of incentive regulation up to 1969 can be found in Section III in (Posner, 1999). The first approaches to incentive regulation were based on rate freezing (or lagged price adjustment) as proposed by William Baumol (Baumol, 1967), or profit sharing schemes[13] (Posner, 1999). It is interesting to remark that the author in (Posner, 1999) already discussed several issues that are still relevant nowadays. For example, the author mentions the practical difficulties in assessing the efficiency of regulated firms through adequate analytic tools, how to approach regulation under rapid changes in technology and costs or how to promote innovation. These issues will be discussed in more detail in Section 2.4.

At the same time, theoretical developments acknowledging the existence of asymmetries of information started to appear. Moreover, other practical problems such as regulatory capture, regulatory opportunism, dynamics of regulation, etc. started to be analysed from

[13] Profit sharing consists of allowing a regulated firm to retain part of the cost reductions it has achieved, passing the remaining percentage through to consumers.

a theoretical perspective as well. This branch of the literature was referred as "*The new economics of regulation*" by Jean-Jacques Laffont (Laffont, 1994). The main problem is how to encourage regulated firms to increase their efficiency and share these gains in efficiency with consumers when the regulator possesses imperfect information, subject to the participation constraint of the utilities. Two main types of problems arise under these circumstances: the adverse selection and the moral hazard problems. The following discussion is largely based on (Joskow, 2008).

The adverse selection problem refers to the fact that the regulator may fail to identify what would be the real efficiently incurred costs of the different firms. Thus, in order to comply with the firm's viability or participation constraint, the regulator may set prices that are too high as compared to the costs that would be incurred efficiently. This could be mitigated by establishing more frequent price ratchets, similarly to the conventional cost-of-service regulation.

However, frequently matching costs with revenues/prices would remove any incentive to the firm to reduce its costs to a more efficient level. This is because after spending managerial effort into reducing its costs, the regulator would not allow the firm the benefit from this reduction. Therefore, frequent price reviews may lead to a lack of managerial effort to reduce cost to an efficient level. This is known as moral hazard problem. Freezing prices (modifying them to account for exogenous factors that cannot be influenced by managerial effort) would provide firms with incentives to reduce costs since they would earn the price differential. Nevertheless, a permanent price freeze would leave all the welfare gains to the firms whilst not sharing it with consumers.

Consequently, any regulator has to address the adverse selection and moral hazard problems subject to the firm's participation constraint. Publications on incentive regulation make different assumptions regarding the amount of information possessed by the regulator, when this information is known by the regulator (ex-ante or ex-post), the regulator's objectives and capabilities, the interaction over time between regulator and firms and the long-term commitment of the regulator. For a review of the theoretical literature on incentive regulation the reader is referred to (Laffont and Tirole, 1993) and (Armstrong and Sappington, 2005).

The previous discussion seems to yield two apparently opposite types of regulation: a pure cost of service and a permanent price freeze or price cap. The former approach would fail to solve the moral hazard problem, whereas the second is subject to the adverse selection problem and performs poorly at rent extraction, i.e. sharing cost reductions with consumers. Nonetheless, real-life cost-of-service regulation was in fact somewhere in between these two approaches due to the existing regulatory lag. Moreover, the first incentive regulation proposals made in (Baumol, 1967) could be seen as some kind of formalisation of the regulatory lag.

However, the true landmark in the boosting of incentive regulation took place in 1983. This year, a report written by Stephen Littlechild regarding how to regulate BT (British Telecommunications) after privatisation was published (Littlechild, 1983). Littlechild then proposed to limit the prices charged by BT according to a RPI-X formula, under which prices could only increase annually, in per cent terms, as much as the retail price index (RPI) minus a certain X value.

This report, which is probably scarcely read[14] due to the inexistence of an electronic version (Stern, 2003), not only lead to the implementation of RPI-X regulation for BT, but also for other regulated sectors in the UK and worldwide. Littlechild probably did not foresee at that time the consequences of his proposals, particularly as he intended RPI-X to be a temporary mechanisms until competition in telecommunications developed (Stern, 2003). However, since then, different variations of the scheme he proposed have been developed and implemented as permanent forms of regulation in sectors such as electricity and water networks. For more information on the writing of the "Littlechild Report" and its consequences, the reader is referred to (Alexander et al., 2003)

An open question in the RPI-X, besides what costs should be subject to this price control, is how to determine the X. This parameter should internalise the true opportunities of regulated firms to increase their efficiency by reducing prices in real terms (correcting for inflation). However, this efficiency can reflect numerous factors. Generally, efficiency, or productive efficiency, can be divided into two main components: allocative (or price) efficiency and technical efficiency (Farrell, 1957). Allocative efficiency is related to whether the firms use the appropriate combination of their different inputs, producing the same amount of outputs, given the different prices of the inputs. Thus, a firm would present allocative inefficiency if using an efficient amount of inputs, it incurs in extra costs since a different combination of inputs within the same cost function would be less costly. On the other hand, a firm would be technically inefficient if it uses more inputs than would be necessary to produce the same outputs[15].

Furthermore, the measure of technical efficiency may comprise a pure technical efficiency and scale efficiency, i.e. whether firms are operating at appropriate scales. Moreover, if efficiency indices are measured over time, an overall change in efficiency could take place due to factors non-controllable by the firms such as technology evolution (Jamasb et al., 2004). This is known as frontier shift.

RPI-X was proposed by Littlechild so as to provide regulated firms with stronger incentives to increase efficiency. However, it was soon found out that these firms could try to reduce costs at the expense of deteriorating quality of service. Therefore, it is widely acknowledged that RPI-X regulation requires some additional mechanisms to control quality levels (Littlechild, 1988; Giannakis et al., 2005; Joskow, 2005; Ter-Martirosyan and Kwoka, 2010).

RPI-X regulation, price freezes and profit sharing are not the only mechanism that has been proposed to encourage regulated firms to reduce their costs. In (Schleifer, 1985), the concept of yardstick competition was proposed. Under this type of regulation, the prices that a firm is allowed to charge or the allowed regulated costs are determined as a function, e.g. the average of the actual incurred costs of other similar firms, excluding its own. Therefore, as the costs actually incurred by any firm do not alter the regulated allowed costs that this same firm perceives, the only way to maximise its profits would be to reduce its costs to an efficient level. One of the main advantages of yardstick regulation is that the regulator does not require an in-depth knowledge of the technologies involved nor perform exhaustive benchmarking of the firms. Cost accounting data should be enough, in theory, to implement such an approach.

[14] The information presented herein about the Littlechild Report is based on other references as a copy of the original report could not be obtained.

[15] This explanation is given from an input-based perspective. A firm could also be technically inefficient if it were possible to produce more outputs with the same amount of inputs.

Nonetheless, yardstick competition faces two main limitations: the susceptibility to collusion among participating firms and the fact that homogeneity among the firms is required. Regarding collusion, (Schleifer, 1985) argues that this effect could be easily limited by the action of the regulator and that in sectors with a large number of firms, collusion would be difficult to exert. On the other hand, the author suggests that the whole sample of firms could be divided into several subsets of comparable firms or regression analysis could be used to estimate an average cost function that depends on a set of non-controllable parameters which would provide the allowed costs of each firm. An example of this latter approach for the case of electricity distribution companies can be found in (Filippini and Wild, 2001).

Finally, a drawback of yardstick competition that Schleifer failed to address lies in the assumption that firms provide a homogeneous product or service. Thus, the quality aspect of the service delivery is neglected. Quality could be considered as a factor of heterogeneity as previously mentioned, thus only firms with similar levels of quality would be compared among them. However, this would remove any incentive for the firms to keep improving the level of quality, which is in at least partly controllable by the firms. The issues of yardstick competition and its effects on quality has been recently addressed in (Tangerås, 2009), from a broad theoretical perspective, and in relation to the case of hospitals in (Koehler, 2006).

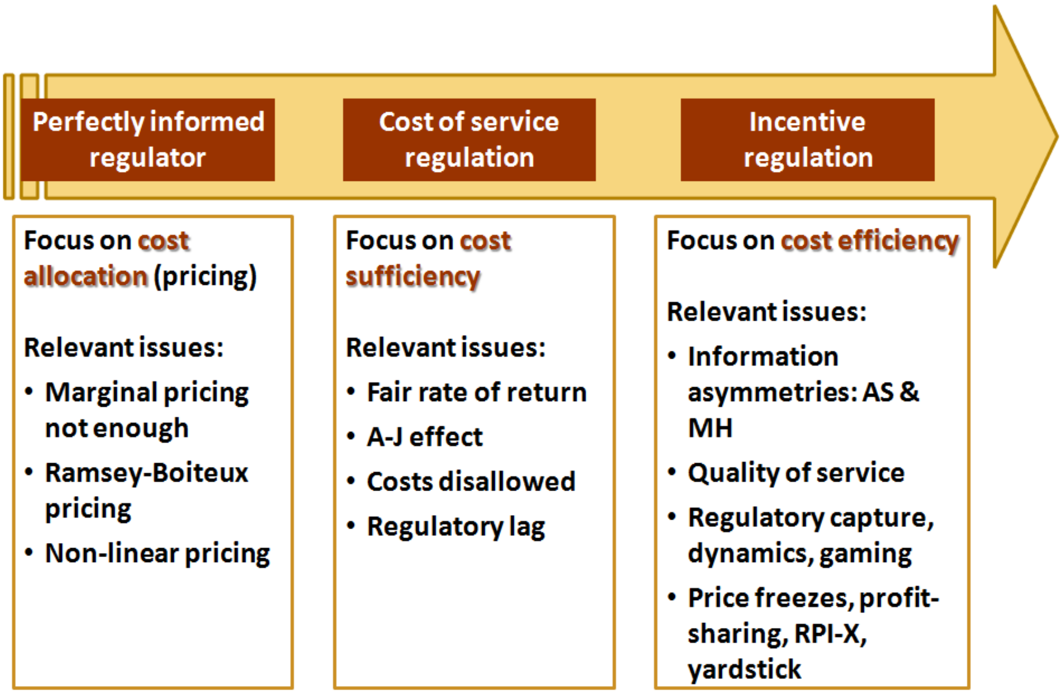

Figure 2-2: Evolution of the theory on the regulation of natural monopolies

2.3 Regulating electricity distribution

The electricity sector has not been impervious to the evolution of regulatory theory and practices that was described in the previous section. Nonetheless, as mentioned in the introductory chapter, it was not until the late 80s or early 90s that deregulation and liberalisation was introduced in the electricity sector. Consequently, the electricity distribution activity and DSOs did not exist as such until that moment. As can be seen in the review provided in the previous section, at the time of deregulation incentive regulation was already known and some practical experiences in other sectors existed.

Consequently, incentive regulation started to be implemented in some electricity distribution sectors almost since their birth as stand-alone activities.

Nowadays, some kind of incentive regulation, especially RPI-X regulation, is in place is most parts of South America and Europe (see (Rudnick et al., 2007) for South America, (Cossent et al., 2009) for an overview of EU countries and (Jamasb and Pollitt, 2007) for the UK[16]). Regulatory periods typically range from 3 to 5 years. On the contrary, US regulatory frameworks have traditionally been closer to a pure cost-of-service approach. Notwithstanding, (Comnes et al., 1995) show that some (vertically integrated) electric utilities were already subject to some form of incentive regulation in the early 90s, which they named performance-based ratemaking. Moreover, over the last years more and more states are implementing different incentives to increase efficiency[17] (The Edison Foundation. Institute for Electric Efficiency, 2010) or improve quality of service (Edison Electric Institute, 2005).

Some other countries such as Sweden or New Zealand followed a less burdensome regulatory approach usually named light-handed regulation or self-regulation (Gunn and Sharp, 1999; Jamasb and Pollitt, 2008). This basically consists of performing relatively lax ex-post controls of the prices charged or the rates of return obtained in such a way that the regulator only intervenes in case abnormal deviations occur. This was generally accompanied by information disclosure requirements to the utilities. However, this lack of regulatory control can lead to excessively high profits for DSOs. This was proved by (Bertram and Twaddle, 2005) for the case of new Zealand. Therefore, regulators have developed different types of methodologies common to all DSOs, which can be considered as benchmarking tools, to perform ex-post controls such as the network performance assessment model (NPAM) in Sweden (Larsson, 2005) or the optimised deprival value in New Zealand (New Zealand Commerce Commission, 2002). This could be in fact as a form of incentive regulation.

Despite the fact that some countries have by now more than two decades of experience with incentive regulation for electricity networks, it is rare to find empirical assessments of the performance of this regulatory approach. The existing studies analyse most extensively countries in South America (Estache and Rodríguez-Pardina, 1999; Rudnick and Zolezzi, 2001) and the UK (Domah and Pollitt, 2001; Jamasb and Pollitt, 2007), albeit some studies can be found for other countries too (Asia Pacific Energy Research Centre, 2000; Nillesen and Pollitt, 2007) or one study comparing several European countries (Cambini and Rondi, 2010). These studies use different indicators to measure the performance of incentive regulation (and liberalisation) over time, thus making it difficult to set comparisons. These indicators comprise electricity tariffs[18], energy losses (technical and/or non-technical), continuity of supply indices (which vary among countries), electrification rates (relevant for developing countries), labour productivity (number of staff per GWh), investment rates, distribution charges (monetary units per kWh) or distribution revenues.

[16] Other European countries implemented some form of incentive regulation since privatisation too. However, due to availability of information and the use of native languages, publications have not focused as much on these countries.

[17] Since in the US it is very common to find integrated distribution companies, i.e. those performing retailing and/or generation as well, a lot of emphasis is placed on revenue decoupling and energy efficiency. Note that these issues become much less relevant for fully unbundled distribution network companies.

[18] Full electricity tariffs are used as an indicator in case distribution and supply are integrated.

The diversity in the indicators analysed shows that it is not straightforward to determine the appropriate indices to measure the performance of incentive regulation. It is clear that reducing energy losses, improving continuity of supply indices or increasing electrification rates will have a positive effect on consumers. Nevertheless, it is arguable whether these improvements have been attained as a result of incentive regulation itself or, alternatively, these are the consequence of other broader policies or developments. Additionally, full electricity tariffs are mostly used to measure sector-wide benefits of restructuring rather than the effects of distribution regulation. Furthermore, labour productivity can be seen as an indicator of efficiency, although it must be used together with some measure of the cost of capital as tradeoffs exist between these two components (Jamasb and Pollitt, 2003). Consequently, distribution charges and distribution revenues, when expressed in real terms, would be the most suitable indicator to measure the performance of incentive regulation. However, this assertion may remain true as long as the exogenous variable such as technology, quality and environmental requirements or the type of service provided do not change significantly. As it will be shown in the next section, these variables may change substantially for electricity distribution over the next years. Thus, new measurements to evaluate the result of regulatory frameworks will probably be required.

In spite of the potential shortcomings of the measurements used, which in any case seem very difficult to avoid completely, the previous studies generally report notable improvements in cost efficiency and quality of service after the introduction of incentive regulation. Notwithstanding, as pointed out in (Joskow, 2008), many studies focus on developing countries where the performance of electric utilities before liberalisation may have been very poor. Thus, the improvements cannot be easily attributed to incentive regulation alone, but also to privatisation and restructuring.

An added difficulty to the assessment of the results of incentive regulation can be found in the frequent regulatory changes that have taken place. In fact, it is difficult to find a country where the same rules were applied for two consecutive regulatory periods. These frequent modifications respond to the fact that practical application of incentive regulation, and particularly its use on electricity distribution companies, has proved to be more challenging than what *on paper* proposals suggested. As a result, actual applications of incentive regulation include some elements that have been traditionally associated with cost-of-service price ratchets and yardstick competition such as regulatory accounting or benchmarking across firms (Joskow, 2008). Among the causes for the frequent regulatory changes and deviations from textbook incentive regulation, particularly when regulating electricity distribution, we may find the following:

- After unbundling, DSOs do not sell electricity nor generate it. Thus, the service they provide is not electricity anymore, but the access to the electricity system complying with certain quality standards. This is a product much more difficult to define precisely. Moreover, nowadays, DSOs offer this service not only to end consumers, but also new network users such as DG.
- In many theoretical developments, the focus is generally placed on pricing of the services. However, in electricity distribution the focus is generally placed on the allowed revenues or costs instead of on pricing issues. What is more, in many countries distribution tariffs are set directly by the regulator as part of an access tariff without the intervention of DSOs. Therefore, the focus is generally placed on evaluating the efficiency of the costs incurred by DSOs and setting incentives to reduce these costs. A mostly inelastic electricity demand and the fact that

distribution charges generally account for about just 25% of the total cost of electricity may dilute the pricing effects at distribution level.

- Textbook RPI-X regulation takes as starting point the existing prices. However, in practice, regulators do not generally feel at ease accepting actual prices or costs as given. Hence, burdensome efficiency analyses are generally carried out either to assess the efficiency of the costs incurred during the last regulatory period (ex-post regulation) or forecast the future investment needs of DSOs (ex-ante regulation). For these purposes, regulatory accounting and benchmarking tools have been and are still being extensively used by regulators. In spite of the use of these tools, regulating capital expenditures has turned out to be a very difficult task.
- In the literature, costs are generally assumed to vary with the amount of energy distributed alone (once some sunk costs have been incurred). Nonetheless, actual distribution costs greatly depend on exogenous variables such as geographical constraints, number of customers, load density, weather, etc. The importance of these variables can vary significantly from one region or country to another.
- Theoretical developments have generally considered quality as a one-dimensional variable with a known relation with distribution costs/price. However, neither of these two assumptions hold true in reality. Quality of service in distribution networks implies controlling for many different factors, on which network users may also have an impact on. Among the quality issues that are generally deemed relevant in distribution networks, one may find energy losses, continuity of supply, power quality or customer attention. Moreover, several different indices can be used to measure each one of the former aspects. Additionally, quantifying the relation of quality with distribution costs and the value of quality for consumers is not straightforward.

Overall, this section has shown that incentive regulation has been widely applied in electricity distribution since the electricity sector liberalisation. Nevertheless, the implementation of this type of regulation in practice has proved to be much more challenging than expected beforehand. These difficulties will be addressed in more detail in subsequent chapters. In any case, empirical evidences denote that incentive regulation has indeed yielded beneficial results over the last decades (Jamasb and Pollitt, 2007). Notwithstanding, the question that arises now is whether incentive regulation is still fit for purpose for the years to come. This is precisely the topic addressed in next section.

2.4 New challenges faced by distribution networks and their regulatory implications

Distribution networks are facing times of rapid changes which pose demanding challenges for DSOs. A myriad of factors could be mentioned among the causes of this situation. Nonetheless, all these can be categorised into two major types of drivers: climate change mitigation policies and the new requirements of network users (ERGEG, 2010).

Climate change and its effects is nowadays one of the major concerns of humanity. Hence, the mitigation of climate change is one of the issues at the top of the agenda –at least in theory- of many governments and policy-makers worldwide. In this context, the energy sector in general and the electricity sector in particular have been largely affected by the policies aiming at the reduction of CO_2 emissions. Increasing the sustainability of the energy sector has lead to policies promoting demand response, renewable energies and energy efficiency. Furthermore, transforming the transportation sector is another key priority. In this sense, there are several alternatives to conventional vehicles such as hydrogen vehicles, natural gas vehicles, biofuels and electric vehicles. Among these, electric vehicles seem one of the most promising technologies for the medium to long-term (Contestabile et al., 2011).

Consequently, increasing amounts of DER are being connected to distribution networks. At the moment, DG is the only DER which presents significant penetration levels. Nonetheless, a roll-out of smart meters is taking place in many countries, which will be presumably followed by the implementation of demand response programs. Furthermore, EVs are expected to start developing in the coming years as the offer provided by car manufacturers grows. Distribution networks were not originally designed taking this factor into account; hence, this integration has an important impact on the operation and planning of these networks. This impact brings about some regulatory implications which oblige a revision of current regulatory frameworks. At the same time, the new DER connected to distribution grids become network users with specific needs that should be met by DSOs.

On the other hand, modern societies increasingly depend upon electricity supply. For example, Figure 2-3 shows the interdependences of several essential services, which reveal the key role of electricity supply nowadays. The consequences of a blackout were clearly illustrated by the effects of the 2003 blackout in the Northeast of the United States. Similarly, residential, commercial and industrial consumers own more electric and electronic devices at their premises, which cannot work without an appropriate electricity supply. Therefore, high levels of security and quality of electricity supply are essential to meet society and end consumers' needs.

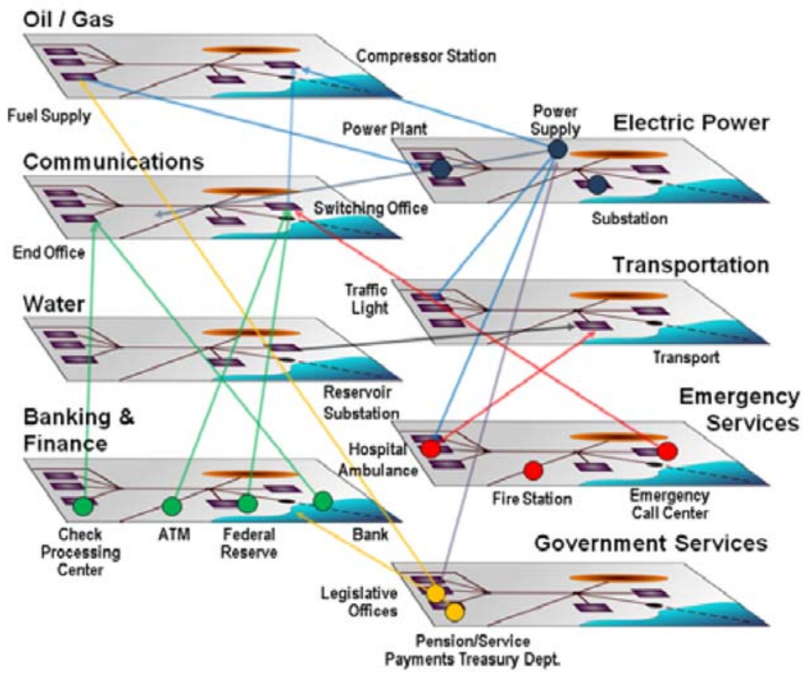

Figure 2-3: Interdependences among different essential services (Foster et al., 2004)

Smart grids are seen by many as an essential component of the solution that is needed to respond to the aforementioned challenges (European Technology Platform-Smartgrids, 2006; ERGEG, 2010; Eurelectric, 2011; European Communities, 2011; International

Energy Agency (IEA), 2011). Nonetheless, implementing smart grids requires significant investments in new technologies and changing the current operational practices. Additionally, smart grids require the active involvement not only of DSOs, but also all network users. However, current regulatory frameworks are not deemed adequate to drive this change. Therefore, regulation must be revised in order to facilitate and promote the investment in smart grid technologies as well as to foster network users to behave actively (Meeus et al., 2010; OFGEM, 2010; Eurelectric, 2011).

Hereinafter, the regulatory implications of the large-scale connection of DER, especially DG, and the transition towards the smart grids will be reviewed. This review will constitute the basis for the regulatory recommendations that will be provided in the remainder of this thesis.

2.4.1 Integration of distributed energy resources and distribution regulation

The connection of DER in large amounts drives profound changes in the way distribution network have been traditionally planned and operated. The magnitude and direction, either positive or negative, of this impact depends on many factors, many of which are outside the control of DSOs. The role of regulation should be to set the appropriate conditions so that the potential benefits brought about by DER can be maximized whilst mitigating any possible adverse effect.

Peak demand of passive consumers has traditionally been the major driver for distribution network investments. Thus, the grid was designed with enough capacity to accommodate peak demand in adequate quality conditions. However, the presence of generation units in the lower voltage levels opens the possibility to defer or avoid network reinforcements, as pointed out in numerous publications (Gil and Joos, 2006; Méndez et al., 2006a; Piccolo and Siano, 2009; Wang et al., 2010). This is due to the fact that DG production offsets local consumption, thus reducing the loading of network components. Demand response and V2G strategies could produce similar effects as shown in (Conchado, 2011) and (Clement-Nyns et al., 2011) respectively. In fact, Article 25.7 of EU Directive 2009/72/EC (European Communities, 2009) states that DSOs shall consider DG, together with demand side management, as an alternative to investing in new network assets.

However, this is hardly materialised in practice mainly because of the absence of adequate regulatory incentives. This is especially relevant in systems where distribution is unbundled from generation as the DSO cannot decide over the location and operation of generators. Therefore, many of the proposals to integrate DG in distribution network planning that can be found in the literature (Dugan et al., 2001; El-Khattam et al., 2005; Alarcon-Rodriguez et al., 2010) cannot be directly applied in a European context. Consequently, DSOs tend to neglect the potential contribution of DER in network planning in order to avoid potential operational problems. (Cossent et al., 2011c) show that this can have a major impact on distribution costs in areas with large penetration levels of DG. Their most relevant results are summarised in Figure 2-4, which shows that costs can even double if massive amounts of DG are connected in a small area.

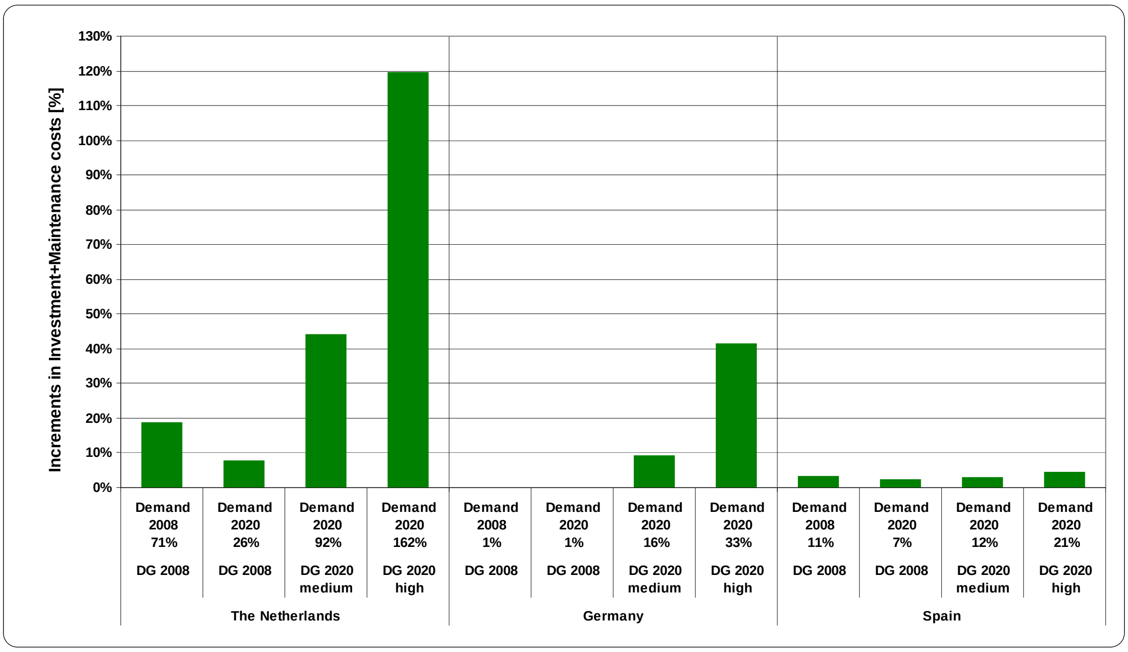

Figure 2-4: Impact of DG on distribution costs in three distribution areas under a conventional planning approach (Cossent et al., 2011c)

(Cossent et al., 2010) built on the work presented in (Cossent et al., 2011c) by quantifying the expected benefits of the implementation of more advanced planning criteria. As depicted in Figure 2-5, a more active role of DG and consumers can yield savings in total distribution costs (within the area) of more than 30% under some circumstances. Using similar modelling approaches, (Mateo and Frías, 2011) and (Pieltain Fernandez et al., 2011) concluded that controlled EV charging is required to prevent DSOs from being forced to reinforce LV and MV grid. Otherwise, significant investments could be required due to the increase in local peak demand caused by EVs.

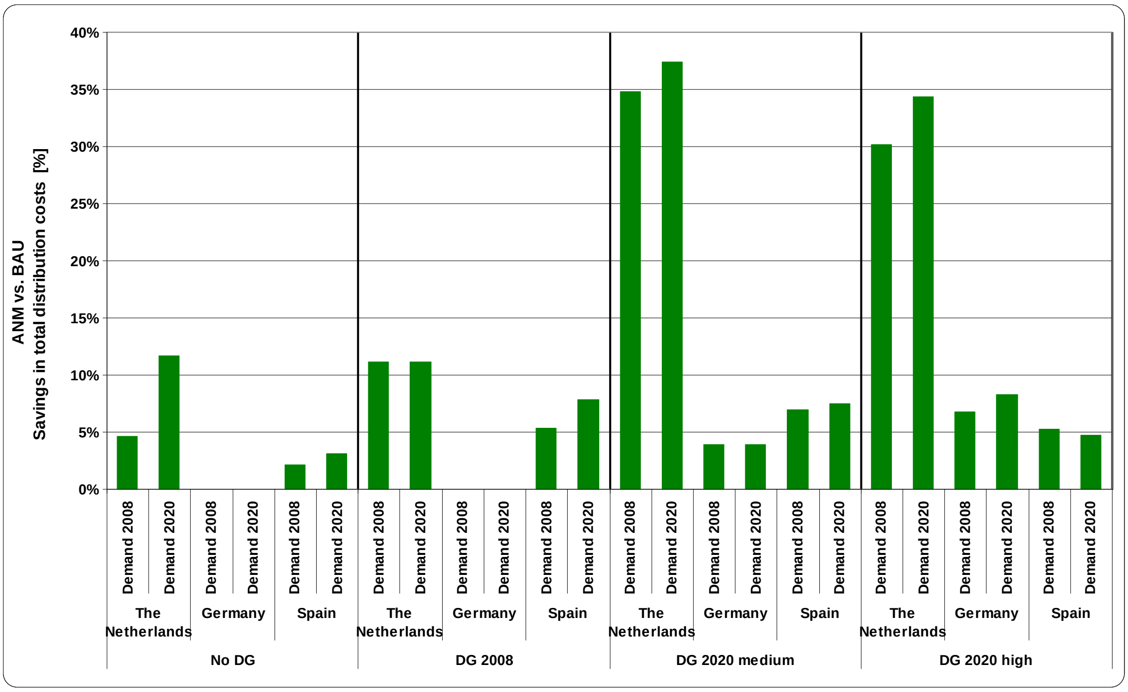

Figure 2-5: Network costs in a Dutch area under a passive (business as usual-BAU) and an active (active network management-ANM) planning approaches (Cossent et al., 2010)

Notwithstanding, there are no clear regulatory mechanisms to attain these benefits. The first proposal was that of UK's Engineering recommendation P2/6 (Energy Networks Association, 2006), which defines a probabilistic methodology to compute the contribution of DG to meet peak demand depending on the technology of DG and the moment when peak demand occurs. Nonetheless, as long as DSOs bear full responsibility for quality of service, a failure in a DG unit or a deviation from the consumption forecasted may result in non-supplied energy and penalties to DSOs. In order to overcome this hurdle, (Trebolle et al., 2010) propose to engage DG in network planning through optional long-term contracts between DSOs and DG owners named reliability options for DG (RODG) issued on the basis of market mechanisms. Any DG unit that has subscribed a RODG would receive a premium in exchange for the commitment to be producing during the hours previously agreed with the DSO. Failing to fulfil this obligation would imply paying a penalty. In principle, these schemes could be open to the participation of demand aggregators.

Distribution network operation has been traditionally characterised by a very limited monitoring and control capabilities over the state of the grid, especially the MV and LV levels. This was mainly due to economic reasons. Under these circumstances, these grids were kept in a radial configuration in order to facilitate their design and operation. Electricity flowed from the upper to the lower voltage levels up to end consumers since embedded generation was almost non-existent. However, the connection of generators may create significant disturbances in technical parameters under conventional operational practices. The main issues affected comprise voltage control, protections, power quality and energy losses.

Despite DG may mitigate voltage drops if located close to loads, DG can cause several voltage problems, such as malfunctioning of capacitor banks or tap changers, when the grid is passively operated (Walling et al., 2008). Moreover, certain types of DG units may create power quality problems. For example, inverter-based generators can increase the injection of harmonics to the network or small generators connected to a single phase can increase imbalances among phases (Passey et al., 2011). Additionally, protection systems may not be adapted to the existence of active elements in distribution grids that contribute to short-circuit currents. Therefore, problems such as fuse blowing, sympathetic tripping or relay desensitizing could arise (Walling et al., 2008). Furthermore, it is well known that unintentional islanded operation may occur when several DG units operate in parallel in areas where the mismatch between local generation and demand is small (Passey et al., 2011). In case of unintentional islanding, different equipment can be damaged (inverters, consumer devices, network components) and even pose security threats for technicians.

Given the wide variety of potential effects of DG on distribution networks, several authors have attempted to develop a reduced set of indices to analyze these problems in a more simplified way so as to facilitate certain tasks of distribution companies (Chiradeja and Ramakumar, 2004; Ochoa et al., 2006; Gil and Joos, 2008; Ochoa et al., 2008). However, it is still uncertain how to apply these indices in practice since several different factors should be considered, e.g. time-varying generation conditions, network reconfiguration, existing protection schemes, etc. The work of (Ochoa et al., 2008) represents a first step in this line by considering the time-varying conditions of DG production and demand.

Many of the aforementioned problems can negatively affect the number and duration of the interruptions suffered by consumers or require investments to avoid any potential problem. Therefore, the previous impacts of DG can also affect the revenues of DSOs.

Finally, (Méndez et al., 2006b) showed that DG may reduce energy losses under moderate penetration levels. Nonetheless, the amount of energy losses increases again after a certain level of penetration. This impact depends upon many factors such as the DG technology, concentration of DG, type of grid, load density, power factor, etc. Similarly, demand side strategies could be used to reduce energy losses at distribution level (Shaw et al., 2009). This issue is particularly relevant to this thesis given that DSOs are generally encouraged to minimize losses through different types of incentive mechanisms.

Consequently, modifying conventional operational practices is necessary to efficiently integrate DG and other DER. Nonetheless, this requires, on the one hand, more active network management strategies by DSOs and, on the other hand, a more active role of DER (Peças Lopes et al., 2007; Strbac, 2008). DER could even provide certain ancillary services at distribution level such as congestion management, voltage control or islanded operation to improve quality of service (McDermott and Dugan, 2003; ILEX Energy Consulting and UMIST, 2004; Peças Lopes et al., 2007; Belhomme et al., 2009; Van Thong and Belmans, 2010; Clement-Nyns et al., 2011). Several authors even state that DER could offer their services at transmission level to improve system operation (ILEX Energy Consulting and UMIST, 2004; Heffner et al., 2007; Peças Lopes et al., 2007; Guille and Gross, 2009; Shayesteh et al., 2009).

However, the necessary commercial and regulatory arrangements for this to happen are not in place. Regarding commercial arrangements, the development of aggregation agents in charge of managing large numbers of DER, mainly EVs and loads, is seen as a requirement (Belhomme et al., 2009; Guille and Gross, 2009; Bessa and Matos, 2011). On the regulatory side, a myriad of factors ought to be addressed, many of them specifically for each type of DER, including aspects like defining the roles of each agent involved, metering schemes, design of retail tariffs, design of RES support payments, distribution grid connection policies, distribution use of system charges, market design, development of distribution grid codes, economic regulation of DSOs, unbundling of activities, standardisation (Keane et al., 2007; Batlle and Rodilla, 2009; Cossent et al., 2009; Niesten, 2010; Cossent et al., 2011a; Gómez et al., 2011).

A detailed analysis of all these issues falls outside the scope of this thesis. The focus hereinafter will be placed on those issues specifically related to the economic regulation of DSOs, i.e. the determination of allowed revenues or prices and other regulatory incentives. Nonetheless, appropriate economic signals for DER should be implemented as a complement of any modification in the economic regulation of DSOs, should it be effective. Hence, the main questions that will be addressed in subsequent chapters regarding the integration of DER are the following:

i. **Determination of allowed revenues/prices:**

Regulation should compensate DSOs for the incremental costs driven by DG and other DER. (de Joode et al., 2009) propose several possible mechanisms for this such as a partial cost pass-through, modifying efficiency requirements (X factor) according to DG penetration rates, adding DG-related revenue drives to the remuneration formula or mixed mechanisms. The UK has pioneered the application of these schemes to electricity distribution regulation by combining a DG revenue-driver with a partial pass-through (OFGEM, 2009). Similar mechanisms could be devised for costs driven by EVs or demand response. Notwithstanding, at the same time, DSOs should be encouraged to do this efficiently by promoting them to take advantage of the possibility to defer network investments and adopt innovative solutions that may increase OPEX at the expense of reduced CAPEX by purchasing network services from DER (Cossent et al., 2009; Frias et al., 2009). Therefore, the overall revenue computation should avoid creating separate incentives for OPEX and CAPEX.

The amount of energy distributed is frequently used as a DSO revenue driver, for instance in price cap or revenue yield regulations. However, this is only valid as long as the behaviour of the users of distribution networks remains stable. DER could lead to a paradoxical situation in which distribution costs increase due to the connection of DER but their revenues decrease because the new DER have reduced the amount of energy distributed. For example, demand side management, or even DG depending of the metering schemes, can produce this effect (Shaw et al., 2010). The opposite situation in which DSOs benefits from an increase of the energy distributed that does not require new investments could happen. A coordinated charging of EVs, typically at night, would increase the annual energy delivered despite requiring scarce network investments (Mateo and Frías, 2011; Pieltain Fernandez et al., 2011). The same would be applicable to the many regulatory benchmarking studies than use the amount of energy distributed as an explanatory variable.

Furthermore, including DG in benchmarking studies as performed in (Agrell and Bogetoft, 2007) may be necessary, especially if it can be considered that the connection of DER increase the heterogeneity across firms, i.e. different DSOs face very different penetration levels. This can happen, for example, in areas with very favourable wind or solar conditions. Moreover, the consequences of DER connection for different types of networks, and thus for different DSOs, can vary according to many factors (Conchado, 2011; Cossent et al., 2011c; Mateo and Frías, 2011). Consequently, benchmarking methods capable of considering the increased heterogeneity and adequately reflect the impact of DER on distribution costs may be required (Cossent et al., 2011b).

How to determine and regulate the distribution allowed revenues will be addressed in chapters 4, 5 and 6 of this thesis.

ii. Incentives to improve continuity of supply:

The potential flexibility offered by DER can be exploited by DSOs to control or improve the levels of continuity of supply (McDermott and Dugan, 2003). For instance, DER can be resorted to in case of a failure in a network component in order to avoid temporary overloads in surrounding network components and reduce service restoration times through a controlled reconnection of the loads interrupted. Additionally, some planned interruptions driven by maintenance works could be avoided by controlling the power injection or withdrawal of local DER. Similar actions could be carried out under emergency situations that would otherwise lead to an interruption. An extreme case would be that of the islanded operation of part of the distribution grid due to the unavailability of upstream grid. However, it is yet to be determined whether these new alternatives will significantly affect the costs of improving continuity of supply and the incentive mechanisms ought to be revised accordingly.

Furthermore, the indices currently used to measure continuity levels are based on the conventional distribution systems where passive consumers were the only users of network services. Nonetheless, it can be argued whether these indices will remain fit for purpose in systems with growing levels of new and more flexible network users. Hence, it may be necessary to rethink how continuity of service is quantified (Cossent et al., 2011b). For instance, DG units connected to the MV grid are compensated in case of interruptions (AEEG, 2011).

Chapter 7 will deal with the problem of regulating continuity of supply in distribution networks under the new environment.

iii. Incentives to reduce energy losses:

The impact of DER on power flows through the distribution grid can significantly affect the energy losses in distribution networks, particularly technical variable losses or copper losses, and the distribution loss factors. DG and demand response could reduce energy losses, although high penetration levels of DG and EVs could produce the opposite effect. The regulatory implications of this are manifold. (Shaw et al., 2010) showed that even if the actual losses were reduced thanks to the contribution of DG, DSOs could be penalised since the ratio of energy losses over energy distributed can increase due to the reduction in the amount of energy distributed and the existence of fixed iron losses. Consequently, it should be determined how to measure energy losses in an appropriate way.

Moreover, the variation of energy losses caused by DER falls outside the control of DSOs. Thus, they could be penalised or rewarded for variations in the amount of energy losses that are caused by DER and do not correspond to any DSO expenditure. This could require revisiting how reference or objective values used in the incentive mechanism are computed (Cossent et al., 2009). In this regard, distribution loss factors, measured as the ratio of average losses over peak losses, have been traditionally used for these purposes. However, the presence of DER will tend to modify loss factors. An uncoordinated charging of EVs and DG producing in periods of low consumption would increase the difference between the maximum and minimum demand, thus increasing loss factors. On the contrary, demand response, a coordinated EV charging and DG producing in times of high demand will smooth the load curves pushing loss factors down. Since this influence can differ in each distribution area and DSO, the use of loss factors in regulation may need to be assessed.

The design on regulatory incentives for DSOs to reduce energy losses will be analysed in chapter 8.

2.4.2 The transition towards smarter distribution grids and distribution regulation

Efficiently integrating large amounts of DG and EVs requires a much higher degree of monitoring and control of distribution networks, particularly MV and LV levels (ERGEG, 2010; Eurelectric, 2011). Thus, future electricity networks will follow a new paradigm widely known as the smart grid. Several definitions of the concept of a smart grid can be found, some of them focus on the technologies involved whereas others focus on the services they are expected to deliver. Despite there is not a clear consensus on what a smart grid is precisely, given that this thesis deals with regulatory topics the "user-centric" definition provided by ERGEG[19] will be adopted herein (ERGEG, 2010):

> *Smart Grid is an electricity network that can cost efficiently integrate the behaviour and actions of all users connected to it – generators, consumers and those that do both – in order to ensure economically efficient, sustainable power system with low losses and high levels of quality and security of supply and safety.*

[19] This definition is largely based on the original definition proposed by the European Technology Platform on Smart Grids.

DSOs are key stakeholders should the transition towards smarter grids be achieved. Given that this is a regulated sector, it must be ensured that regulatory frameworks are fit for purpose. However, it is widely recognized that current incentive regulation schemes present important shortcomings that hamper the realization of smarter electricity distribution grids. Moreover, further efficiency improvements from DSOs may be difficult to achieve, as many of these gains were possible thanks to a starting point in a pre-liberalisation environment, where firms were largely inefficient (Joskow, 2008). Some authors describe the need to revisit the economic regulation of DSOs as the process of *innovating regulation in order to regulate innovation* (Bauknecht et al., 2007; Meeus and Saguan, 2011).

The main goal would be to encourage DSOs to innovate and invest in new technologies and, at the same time, do this in a cost efficient way whilst maintaining quality levels. However, regulators face important challenges in order to achieve this (ERGEG, 2010) (Eurelectric, 2011). Conventional regulatory frameworks encourage short-term cost reductions and asset sweating. Additionally, in many cases, they include frequent ex-post price reviews. However, this is not deemed appropriate in an environment characterised by the need to carry out significant investments under a technological change. The risk of technology obsolescence and *regulatory clawback* together with backward looking regulatory practices create regulatory uncertainty, thus preventing DSOs from investing in new technologies that could yield efficiency gains in the long-term. Additionally, regulators should avoid incurring in micromanagement practices by focusing on the activity inputs as the adverse selection problem is bound to increase under technological change.

Consequently, future economic regulation of DSOs may need to include features such as longer regulatory periods, specific incentives to innovate, equalized incentives for different types of costs (OPEX vs. CAPEX), focus on the outputs of the activity (defined through measurable, objective and controllable by DSOs performance indicators), lighter regulatory scrutiny and limited ex-post reviews. Moreover, regulators should reconsider the tools they used so as to avoid taking a narrow view when evaluating cost efficiency, penalising extra expenditure on R&D or smart grid pilot projects and encouraging business-as-usual expenditure instead (ERGEG, 2010; OFGEM, 2010; Eurelectric, 2011).

However, there is still a lack of consensus as to the most appropriate implementation of these guidelines. (CEER, 2011b) summarizes the responses of different national European regulators and other stakeholders about the actions implemented to promote the adoption of cost-effective network solutions. Most responses correspond to more conventional regulatory practices such as the mere use of incentive regulation and regulatory supervision (Cyprus, Germany, Ireland, Lithuania or Portugal) or performing TOTEX benchmarking (Austria). Nevertheless, this seems insufficient to meet the upcoming challenges as some countries have started to realize. For instance, Sweden is considering the introduction of additional incentives for DSOs to implement smart grid solutions. Furthermore, actual implementations of specific incentives to innovate in grid technologies can be found in Finland, Italy and the UK:

- Finland: smart grid investments are added to the regulatory asset base of network companies valued at standard unit prices.
- Italy: demonstration projects deemed eligible by the regulator are entitled to an extra 2% WACC remuneration for a period of 12 years. These projects have to be implemented in existing “active MV distribution networks”, defined by as MV grids where power flows from MV to HV for at least 1% of the time during the

year. Additionally, real-time voltage control must be implemented and open protocols must be used for communications between the DSO control centre and DER.

- UK: this country became a forerunner in the implementation of DSO innovation incentives in 2005 with the innovation funding incentive (IFI) and registered power zones (RPZ). Under the IFI, DSOs were allowed to increase their revenues up to 0.5% to spend this money in asset management improvement projects. On the other hand, the RPZ provided an extra incentive to connect DG in innovative and cost-effective ways (Cossent et al., 2009). In the last DPCR, the low carbon network funds (LCNF) substituted these incentive mechanisms (OFGEM, 2009). The LCNF consist of a direct payment to DSOs aimed at innovating and testing new technologies, commercial arrangements and network operation strategies. The LCNF comprise tier 1 funds allocated to all DSOs according to the number of consumers to be spent in small projects, tier 2 funds are awarded under competitive schemes to large demonstration projects, and a discretionary reward for those projects deemed worthy of it.

The previous mechanisms would be sorted as input incentives for innovation, according to the classification in (Cossent et al., 2009). Nonetheless, some examples of output regulation can be found. Annex 6 in (CEER, 2011b) provides a comprehensive overview on the use or potential of output measures in regulation as revenue drivers, minimum requirements or for monitoring purposes. This survey reveals that scarce use is made of output indicators at distribution level besides the conventional incentives to improve continuity of supply and reduce energy losses (for more details about the use of these incentives in Europe refer to (CEER, 2008; ERGEG, 2008)) together with voltage quality and customer satisfaction levels. Notwithstanding, some new indices related to smarter distribution grids can be found such as environmental impact of infrastructure (UK, Norway) or the share of network users at the lower voltage levels providing ancillary services (Czech Republic). Hence, further developments are required in this line.

Finally, the most comprehensive regulatory initiative to overhaul distribution network regulation is OFGEM's RPI-X@20 project. This review resulted in the regulation known as RIIO (Revenues equal Incentives plus Innovation and Outputs), whose outstanding features are a focus on output measures with rewards/penalties schemes, 8-year long regulatory periods, specific incentives to innovate, further engagement of stakeholders in regulatory decisions, transparency and stability, long-term view of efficiency, proportionate efficiency assessments to reduce the burden of price reviews and ensured financeability (OFGEM, 2010). Nonetheless, RIIO will not be firstly implemented for electricity distribution until 2015. Therefore, implementation details are not precisely defined yet.

2.5 Summary and conclusions

This chapter started by analyzing the conditions under which economic regulation of a certain sector is necessary, being cost subadditivity and sunk costs the most important ones. Based on a review of existing studies on the characteristics of electricity distribution, it has been concluded that this sector presents notable features of being a natural monopoly. Furthermore, the significant investment requirements create barriers of entry which make it a non-contestable activity. The possibility to introduce competition for the market in distribution has been discussed. However, the intrinsic characteristics of electricity distribution and the ongoing changes in the sector seriously hamper this alternative. Consequently, it is concluded that DSOs should remain subject to economic regulation. This does not prevent them from contracting out specific services under certain terms and conditions.

Moreover, the theoretical and practical approaches to the economic regulation of natural monopolies, and electricity distribution in particular, have been reviewed. This has shown that, supported on theoretical developments, incentive regulation has been widely applied in electricity distribution since the electricity sector liberalisation. Notwithstanding, there are still important challenges to appropriately balance the incentives for DSOs to enhance efficiency whilst ensuring their financial viability and creating a favourable environment to attract investments.

The ongoing transformation of distribution networks characterized by rapid technological developments and the changes in the type and needs of grid users is bound to exacerbate these difficulties and pose additional challenges. Regarding the economic regulation of DSOs, it will be necessary to revisit the processes and tools used to determine the allowed efficient revenues as well as the determination of regulatory incentives related to energy losses and quality of service. Future regulation should create incentives for DSOs to innovate and drive such transformation. Specific incentives to the implementation of innovative technologies and solutions may be needed in the early stages of this process. Different approaches for this are being tested in several countries. Nevertheless, the long-term transition can only be achieved through a suitable regulatory design that avoids creating regulatory uncertainties and provide a stable environment for investments. As it will be shown throughout the document, this is precisely the major target of this thesis.

Main conclusions:

- DSOs should remain subject to economic regulation
- Important challenges remain to encourage DSOs to improve efficiency whilst ensuring their financial viability
- The on-going changes in the distribution sector require revisiting the processes and tools conventionally used to set the allowed revenues of DSOs and the design of regulatory incentives
- The long-term transformation can only be achieved through a suitable regulatory design the avoids regulatory uncertainties and provides a stable investment environment

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3. Incentive regulation in electricity distribution: general framework and regulatory tools

Chapter 1 provided an overview of the role of distribution networks and DSOs as well as the type of costs that are incurred by DSOs. Chapter 2 established the need for regulating DSOs, described the theoretical developments in the field of monopoly regulation and presented some general remarks about the practical implementation of incentive regulation in electricity distribution. This chapter builds on the previous ones by going into further details about the most common approaches to implement incentive regulation schemes in electricity distribution, the practical tradeoffs to be addressed and the different solutions that can be found for these. This description will serve as the basis for the analyses and regulatory proposals that will be presented in subsequent chapters.

Firstly, Section 3.1 will describe the general structure of a revenue cap regulatory framework, i.e. remuneration formula, regulatory periods, process of a price review, etc. Furthermore, section 3.2 introduces the most common tradeoffs or challenges that must be dealt with in real implementations. These difficulties can be mitigated either through use of certain tools or through appropriate regulatory incentives. Section 3.3 reviews how asymmetries of information can be mitigated through appropriate tools and incentive schemes. Lastly, Section 3.4 concludes.

3.1 General remuneration framework

On the ensuing, RPI-X regulation will be considered as the reference for incentive based regulation since it is widely applied to electricity distribution. In fact, other approaches such as price freezes or profit-sharing can be considered as a particular case of RPI-X. Furthermore, a revenue cap formula will be specifically considered because, as stated in the previous chapter, revenue regulation is preferable over price regulation in a context with high presence of DER, uncertain demand and enhanced focus on energy efficiency. This is particularly relevant in a sector such as electricity distribution where the relationship between costs and demand (in terms of energy) is not straightforward. Equation (3-1) shows the basic revenue cap formula.

$$R_t = R_{t-1} \cdot \left(1 + RPI_t - X\right) \qquad (3\text{-}1)$$

Where:

R_t	DSO allowed revenues in year t
RPI_t	Retail price index for year t
X	Revenue adjustment factor

Nonetheless, many different variations can be found. Revenue cap formulas may include the addition of revenue drivers, Z factors to account for unexpected events causing cost deviations, an extra term representing non-controllable costs exempted from efficiency gain requirements, terms accounting for incremental investments or even differentiation per voltage levels. Several remuneration formulas will be presented below for illustrative purposes. The formula in (3-2) includes a revenue driver term, which can account for load growth, new customer connections, etc, or a combination of these (Gómez, forthcoming-b).

$$R_t = R_{t-1} \cdot \left(1 + RPI_t - X\right) \cdot \left(1 + \alpha \cdot \Delta D_t\right) \qquad (3\text{-}2)$$

Where:

α	Economies of scale factor, with values between 0 and 1, which represents the variation of costs with respect to a variation in the corresponding revenue driver
ΔD_t	Variation in year t of a certain revenue driver, e.g. load growth or number of new connections

Equation (3-3) shows the actual remuneration formula used in Portugal. The main features of the Portuguese scheme are that allowed revenues per voltage level, in order to simplify tariff computation, and that a certain share of the revenue depends on the amount of energy distributed. Moreover, a revenue adjustment is made with a two-year lag and another one with a one-year lag to account for unforeseen events (Cossent et al., 2011b). Note that, although this is not shown in the formula, the annual revenues are affected by an efficiency X factor which is revised every three years (ERSE, 2008).

$$R_t = \sum_v \left(F_{v,t} + V_{v,t} \cdot E_{v,t} + O_{v,t} + Z_{v,t-1} \cdot (1 + i_{t-1}) - \Delta R_{v,t-2}\right) \qquad (3\text{-}3)$$

Where:

$F_{v,t}$	Fixed component of revenues for year t and voltage level v [€]
$V_{v,t}$	Variable component of revenues for year t and voltage level v [€/kWh]
$E_{v,t}$	Forecasted energy to be delivered in year t from the voltage level v to consumers in lower voltage levels [kWh]
$O_{v,t}$	Other costs allowed for year t and voltage level v, exempt from efficiency gains [€]
$Z_{v,t-1}$	Unforeseen costs incurred in year t-1 and allocated to voltage level v [€]
i_{t-1}	Interest rate for year t-1 in per unit
$\Delta R_{v,t-2}$	Adjustment in year t of the revenues in year t-2 for voltage level v [€]

Given that the allowed revenues are set for a number of years at each price review, it is necessary to account for inflation. This is generally done through publicly determined inflation indexes, being the most common approach to use a single consumer or retail price index as in The Netherlands (Niesten, 2010) or the UK (OFGEM, 2009a). Nonetheless, regulators may opt to use several price indices in order to account more accurately for the price variations faced by DSOs. For example, the Spanish regulator uses a weighted average of the consumer price index (IPC in Spanish) and an industrial price index (IPRI) (Cossent et al., 2011b).

Under incentive regulation, price reviews or price ratchets are carried out at the beginning of each regulatory period; typically between 3 to 5 years. During these reviews, the regulator usually engages in consultation processes with DSOs and other relevant stakeholders such as consumers, retailers, consultants, etc. Furthermore, the regulator may perform in-house studies to evaluate the past behaviour of DSOs as well as to determine the efficient level of costs that DSOs should incur in the future. In order to do this, the regulatory tools that will be described later in this chapter play a central role. The purpose of price reviews is to set all the parameters that will affect the revenues that will be earned by DSOs over the next years, i.e. allowed revenues, X factors, corrections for inflation, revenue drivers, etc. Additionally, ex-post revenue corrections can be implemented when deemed necessary.

Lastly, as described in the previous chapter, allowed revenues are frequently affected by the quality of service actually provided to network users. In electricity distribution, the most common indicators used to control the performance of DSOs are energy losses and continuity of supply, i.e. supply interruptions. These issues will be addressed in chapters 7 and 8 respectively[20].

3.2 Tradeoffs and challenges faced by regulators

At first sight, incentive regulation may seem straightforward to implement. However, this is not truly the case in practice, mainly due to the existing asymmetries of information between the regulator and DSOs. Under these conditions, the evaluation of efficient investments is a key issue. However, contrary to the case of transmission, analyzing all the potential investment alternatives individually is not possible for regulators. This is due to the fact that distribution network investments are much more numerous, albeit smaller in unitary size, and often complement or substitute each other. Furthermore, comparisons among different DSOs can be hard to implement since the conditions faced by each company can be very different in terms of load density, type of area (urban, rural), weather, etc.

Moreover, CAPEX and OPEX tradeoffs can be very important and difficult to monitor. For example, predictive maintenance (increased OPEX) can be implemented to delay or avoid the substitution of transformers (decreased CAPEX). These difficulties pose several challenges for regulators, which usually require them to balance conflicting objectives. This section will describe the major existing tradeoffs and their implications.

The existence of tradeoffs between OPEX and CAPEX suggest that it would be necessary to evaluate total distribution costs as a whole to prevent inefficient outcomes. This is known as TOTEX approach. In fact, strategic behaviour from DSOs has been empirically observed when a building blocks approach (separate assessments of OPEX and CAPEX) has been used (Jamasb et al., 2003; Jamasb et al., 2004). However, the TOTEX approach is not frequently followed. Due to the inherent difficulties in determining the efficient level of investments in distribution, many regulators base their CAPEX allowances on the firms' own estimates. This creates incentives for DSOs to inflate their CAPEX forecasts as well as prefer CAPEX solutions over OPEX solutions (Ajodhia, 2005). On the other hand, a TOTEX approach may not appropriately reflect the long-term nature of distribution investments and the effect of investment timing (Ajodhia, 2005). Consequently, the regulator faces a tradeoff between avoiding perverse incentives (advantage of TOTEX) and creating a stable environment to attract investments (advantage of building blocks).

One of the main features of incentive regulation is to extend the regulatory lag from 1 year in conventional cost of service regulation to several years. The longer this time, the stronger the incentives perceived by DSOs to cut costs. On the other hand, longer regulatory periods increases the uncertainties faced by regulators over the level of efficient costs. Moreover, this delays the transfer of the cost savings achieved to

[20] Energy losses may not be considered as part of the quality of service provided since this does not directly affect consumers. Nonetheless, energy losses do imply higher power generation costs as well as additional CO_2 emissions. Since most energy losses occur in distribution networks, DSOs are usually held responsible of reducing them through incentive mechanisms.

consumers. Conventionally, a compromise solution was found by performing price reviews every 3 to 5 years. However, it can be argued that a maximum of 5 years is insufficient to really encourage long-term efficiency gains. Therefore, short-term cost reductions, for example by cutting OPEX of simply deferring some necessary investments, may be exclusively sought. This is the reason why OFGEM plans on extending the length of regulatory periods from 5 up to 8 years. In order to mitigate some of the drawbacks of long regulatory lags, a less comprehensive intermediate review will be carried out (OFGEM, 2010a).

The text book formulation of incentive regulation essentially assumes that the regulator sets the allowed revenues at the beginning of each regulatory period and DSOs retain the full difference between allowances and actual costs. However, a purely ex-ante regulation is not generally used in practice due to the risk of DSOs behaving strategically to game the regulator. For instance, DSOs have a clear incentive to inflate their investment forecasts so as to be awarded greater revenue allowances or to defer planned investments in order to appear to have been more efficient (Alexander and Harris, 2005). Therefore, ex-post regulation is simpler to implement since regulators can monitor the actual firms' behaviour. Notwithstanding, ex-post reviews can lead to important regulatory uncertainties derived from the risk of regulatory clawback. These conditions can significantly hamper investments and innovation efforts. Furthermore, regulatory uncertainty can also be the cause of litigation between DSOs and the regulator, as occurred in Sweden (Jamasb and Pollitt, 2008).

Hence, real-life incentive regulation generally follows a mixed ex-ante/ex-post approach through which actual expenditures, particularly network investments, are evaluated ex-post (Gómez, forthcoming-a). In order to mitigate the regulatory uncertainty created by the ex-post component while finding a balance for the existing tradeoff, several mechanisms that perform the ex-post corrections based on rules defined ex-ante have been developed. Among these, one may find the trigger approach, sliding scale and profit-sharing schemes. The trigger approach requires the regulator to monitor each investment project individually (Alexander and Harris, 2005). Therefore, it is only suitable in sectors characterized by large individualized investments, which is not the case of electricity distribution. Consequently, only sliding scale and profit sharing mechanisms will be described in more detail below.

3.3 Dealing with information asymmetries and encouraging efficiency gains

As mentioned previously, the actual application of incentive regulation has proved to be very challenging. In practice, regulators have to overcome the existing asymmetries of information so as to ensure the financial viability of regulated firms whilst encouraging them to increase their efficiency. Under these conditions, activities such as determining ex-ante the allowed revenues of DSOs or assessing ex-post the efficiency of the costs actually incurred can be truly burdensome.

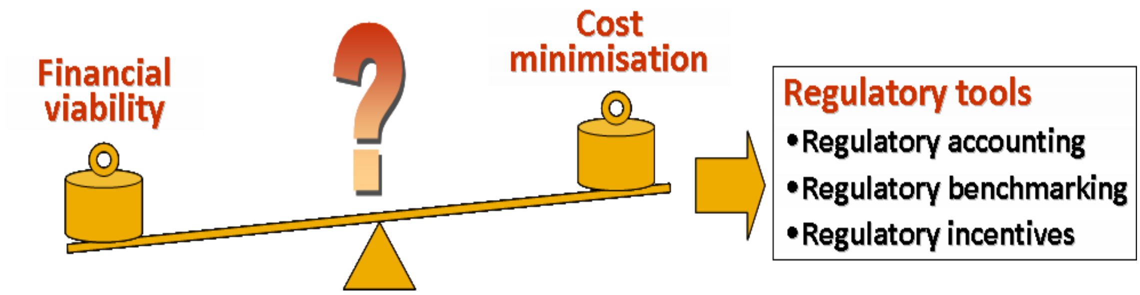

Figure 3-1: Role of regulatory tools in overcoming information asymmetries

Consequently, as illustrated in Figure 3-1 several tools aiming at tackling these difficulties have been developed. The first step is to gather information from the regulated companies regarding their assets, costs, etc. This is done through a standardised accounting known as regulatory accounting system. Once the regulator possesses this information, the next problem that arises is how to evaluate whether the company is being efficient or not. This is the role of the different benchmarking tools that can be found. Finally, it may be necessary to set specific incentive schemes for some aspects which may not be adequately addressed by merely regulating prices or revenues. Hence, different incentive mechanisms can be used to encourage DSOs to behave (or not to behave) in a certain way or to account for uncertainties in the remuneration formula. This section presents an overview of the tools used by regulators in order to overcome asymmetries of information and promote efficiency.

3.3.1 Regulatory accounting

A regulatory accounting system consists of a systematic and standardised system that is used to gather information from regulated firms, in this case DSOs. The regulatory accounting generally comprises a series of templates which utilities fill in with detailed data concerning their costs, assets, etc. This is not strictly a regulatory tool in the sense described above. Nonetheless, an adequate regulatory accounting system is the basis for any regulatory activity. The regulatory accounting system must be carefully designed in order to obtain the information required to perform an adequate assessment and, at the same time, avoiding an excessive burden in collecting and processing the information. Moreover, regulatory accounting system should be auditable and traceable to prevent firms from behaving opportunistically.

In the case of Spain, the detailed cost and assets information that DSOs must submit to the regulator in order to supervise their activities and establish their allowed revenues is detailed in Circular 2/2008 of the CNE (Ministry of Industry Tourism and Trade, 2008). This Circular comprises 75 pages devoted to describe all the different forms that DSOs must fill-in and the corresponding instructions. Another example can be found for the case of Brazil. ANEEL (Brazilian energy regulator) defines all the information to be submitted by DSOs through a distribution grid code (ANEEL, 2011). This grid code comprises more than 200 pages. This gives an idea of how extensive this data collection processes can be.

The design of a regulatory accounting system, in spite of being of utmost importance to the actual regulatory practice, falls outside of the scope of this thesis. On the ensuing, it will be assumed that an adequate and reliable regulatory accounting system is in place for the purposes of this thesis.

3.3.2 Regulatory benchmarking

Benchmarking consists of developing certain measurements, typically related to costs or other variables affected by the performance of the company, against which the behaviour of actual firms can be compared. If the benchmark is appropriately obtained, these techniques can be used to encourage regulated firms to become more efficient over time. Moreover, if the standards used are common for all the firms carrying out a regulated activity, benchmarking can be used to introduce some kind of competition among these companies, which would not naturally appear in the market.

Over the years, regulatory benchmarking has gained greater importance in electricity distribution due to the extensive use of incentive regulation schemes (Jamasb and Pollitt, 2001). Nowadays, many distinct benchmarking methods can be found, ranging from very simple approaches based on comparisons of cost ratios to sophisticated approaches relying on elaborate econometric or engineering models. Chapter 4 will describe in more detail all these different benchmarking methods and propose a comprehensive taxonomy for their classification.

With such a wide variety of approaches, it is important for regulators to understand the major pros and cons of the different approaches so as to select the most suitable tools for their purposes. Therefore, Chapter 6 will focus on comparing the different benchmarking methods among them in order to highlight the main strengths and weaknesses of each approach. Particular attention will be paid to the ongoing changes in the electricity distribution sector.

3.3.3 Design of regulatory incentives

Lastly, incentive/performance-based regulation has been characterized by the introduction into remuneration formulas of additional incentive mechanisms to encourage DSOs to act in a certain manner. The most common incentive schemes are those that aim to promote improvements in quality of service or energy losses reductions. Nonetheless, several additional types of incentives can be found, with different designs. Given that future regulatory frameworks for electricity distribution should strengthen their focus on output measures (OFGEM, 2010b), the design of incentive schemes will presumably gain in importance. Therefore, this section will review the most relevant types of regulatory incentives for DSOs.

3.3.3.1 Incentive/penalty mechanisms

A common way to implement regulatory incentives is through bonus-malus schemes, which consist in setting a reference value for a particular output measure. DSOs are penalised in case they fail to attain this reference value and rewarded otherwise. These schemes are nowadays widely used to promote DSOs to reduce energy losses or improve continuity of supply. Nevertheless, smartgrid developments could bring about similar mechanisms for other output variables, generally known as key performance indicators (KPIs), such as the share of consumers with a smart meter or the per cent reduction in peak demand. A more thorough enumeration of potential KPIs can be found in (Dupont et al., 2010; ERGEG, 2010).

Distinct designs of bonus-malus mechanisms can be found. Figure 3-2 illustrates the parameters that a regulator implicitly or explicitly sets to define the incentive scheme. The relevant parameters are the following:

- Reference value: numeric value of the output measure around which the incentive/penalty system is placed, i.e. for values above the reference, the DSOs will increase its revenues and vice-versa (assuming that an increase in the output measure implies an improvement in the DSO performance).
- Deadband: interval around the reference value within which the DSO revenues do not vary regardless of the value of the output measure.
- β_1 and α_1: The tangent of these angles determine the incentive and penalty that the DSO receive per each unit variation of the output measure respectively. Both parameters are commonly equal for a given incentive scheme. For the sake of simplicity, all the figures are constructed assuming these angles are constant over the whole range of the output variable. Nonetheless, non-linear incentives could be found.
- β_2 and α_2: These angles represent the saturation that is added in some regulatory schemes. Saturation is most commonly implemented through cap & floor levels ($\alpha_2 = \beta_2 = 0$), which are frequently determined as a percentage of the annual DSO revenues.

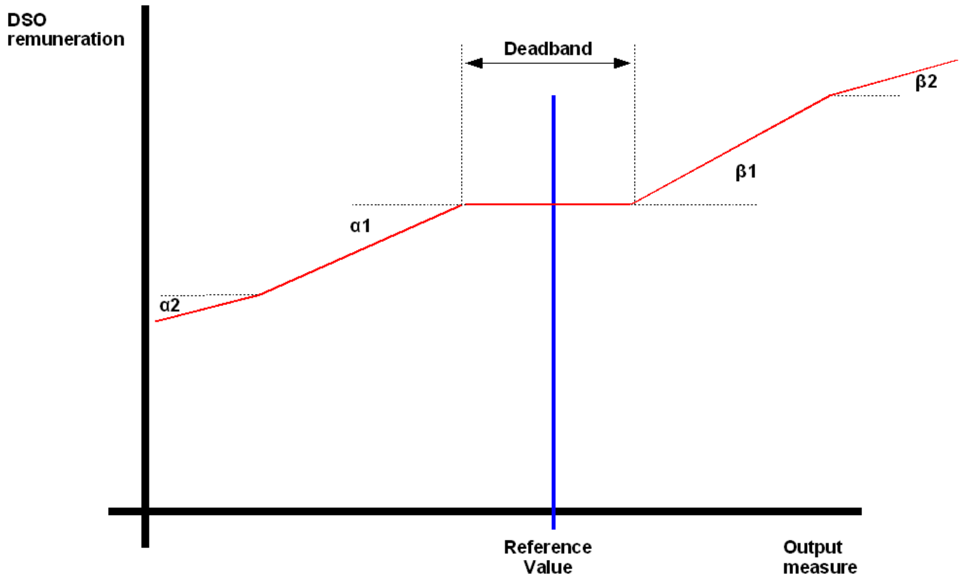

Figure 3-2: Relevant parameters in a bonus-malus scheme

Depending on the values assigned to the previous parameters, several types of regulatory mechanisms can be found, as depicted in Figure 3-3.

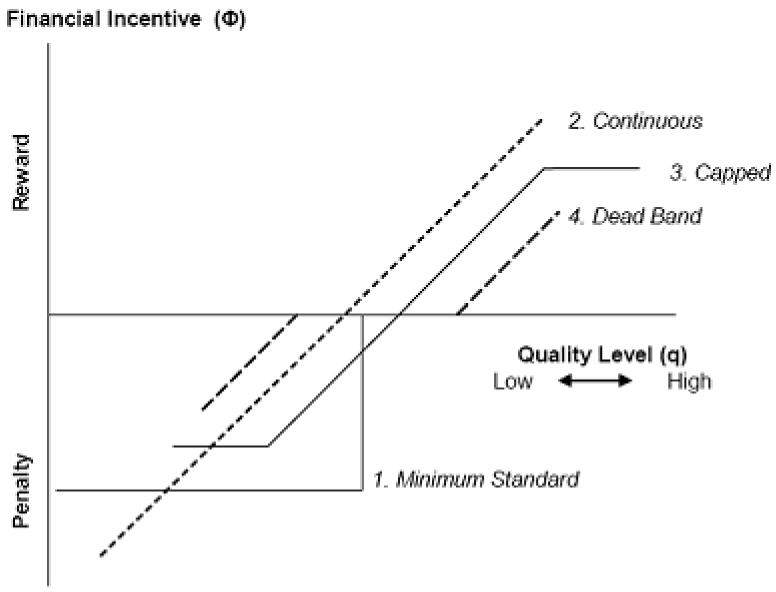

Figure 3-3: Types of reward/penalty regulatory schemes (Ajodhia, 2005)

- Bonus-malus schemes: this is most commonly applied concerning energy losses or continuity of supply. Frequently, the incentives are symmetric, i.e. β_1 and α_1 are the same, and present a cap on the percentage over total DSO revenues that these incentives/penalties can reach in order to limit the risks of DSOs (β_2 and α_2 equal to zero). Moreover, deadbands are relatively frequently added to mitigate the impact of small oscillations on DSO revenues.
- Minimum standard: this scheme provides DSOs with incentives to reach the reference values, i.e. they would be penalised if they do not reach the targets, but no further incentive is provided beyond that point (β_1 equal to zero). An example of this kind of mechanisms can be found in the targets fixed in some countries to install smart meters or the maximum time allowed to connect a new network user. In these cases, the penalty is could be set as a fixed value, then the function would present a step, i.e. α_1 would be 90º and α_2 would be zero; or alternatively a progressive value.
- Pure incentive: this would resemble a "carrot" scheme by which DSOs perceive a premium in case of fulfilling a certain goal. In this case α_1 would be zero and β_1 strictly greater than zero. An example of this type of mechanism is the "stakeholder engagement" incentive implemented by OFGEM in the DPCR5.

In practice, the implementation of this type of mechanisms faces important practical difficulties. These are related, for example, with how to measure the output variables regulated under this scheme or how to determine adequate incentive/penalty rates. These issues will be addressed in more detail in the context of continuity of supply regulation and energy losses respectively in chapters 7 and 8 respectively.

3.3.3.2 Ex-ante/ex-post mechanisms: sliding scale, profit sharing mechanisms, menus of regulatory contracts

In purely ex-ante incentive regulation systems, DSOs are fully exposed to any deviation between actual costs and allowed revenues/prices. Thus, DSOs may incur in high earnings or losses as a result of deviations between ex-ante allowances and actual costs. In order to mitigate this undesirable characteristic of purely ex-ante regulation, several mechanisms can be found to share the risk between DSOs and consumers by distributing cost deviations according to some predefined rules. Sliding scale and profit sharing schemes are the most common approaches.

(Viscusi et al., 2005) describes a possible application of sliding scale regulation based on an ex-post correction of the allowed rate of return, *r*, earned by the regulated firms, shown in (3-4). A value of unity for the sharing factor *h* would correspond to a cost-of-service regulation, whereas a value of zero for this factor would represent a pure incentive regulation system. Intermediate values for *h* correspond to a profit sharing system, being the power of the incentive to reduce costs the closer to zero the value of the sharing factor is.

$$r = r_t + h \cdot \left(r^* - r_t\right) \qquad \textbf{(3-4)}$$

Where:

h represents the sharing factor, which is a constant ranging from 0 to 1,

r_t is the rate of return obtained by the company in year t as a result of the tariffs set in the preceding rate case

r^* is the reference/target rate of return.

A similar sharing mechanism can be applied to overall revenues or prices instead of to rate of returns, as a complement to performance based regulation. In these cases, the mechanism is frequently called profit or earning sharing scheme. (Comnes et al., 1995) analyze several examples of application of these mechanisms to different US utilities. Their comparison is summarised in Figure 3-4.

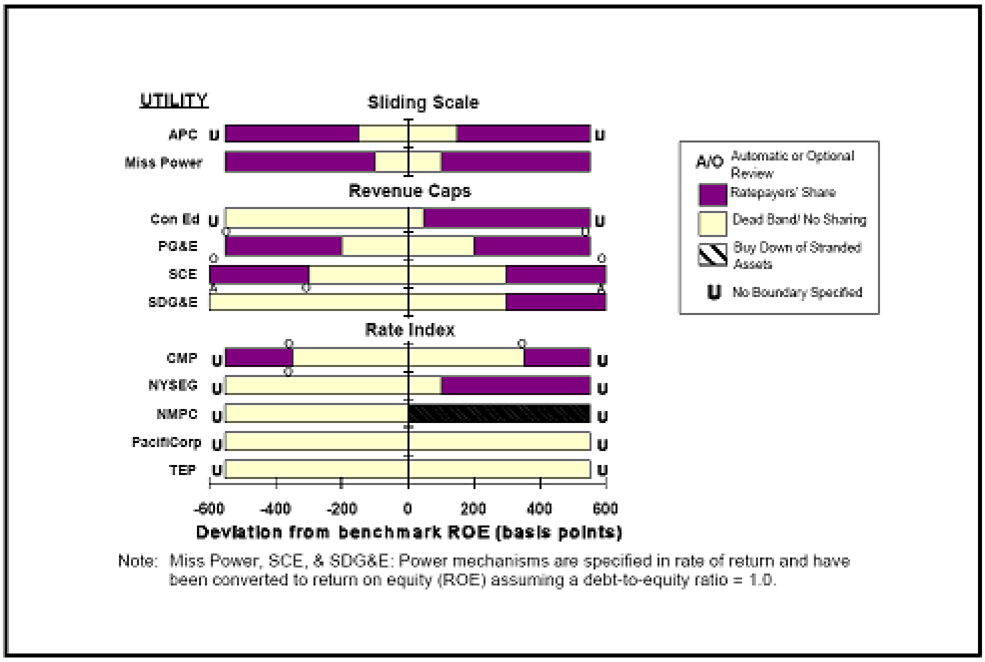

Figure 3-4: Examples of earning sharing mechanisms in the US (Comnes et al., 1995)

However, sliding scale mechanisms are still prone to suffer from adverse selection problems, in spite of mitigating their negative consequences. (Laffont and Tirole, 1993) argue that a regulator can perform better by offering regulated firms a menu of contracts. Some of these contracts would be closer to a pure cost of service regulation and others to a pure price/revenue cap regulation. In Viscusi's formulation, this could be implemented through different pairs of values for the reference rate of return and sharing factors. Firms which are capable of achieving large gains in efficiency would tend to opt for a high powered regulatory contract (closer to price/revenue cap), whereas firms with less opportunities to do so would choose a low-powered scheme (closer to cost of service). Hence, companies would tend to reveal their true cost opportunities to the regulator, thus reducing asymmetries of information.

(Rogerson, 2003) builds on this work by proposing a design of menus of contracts that is allegedly simpler than the optimal one proposed by Laffont and Tirole but capable of attaining most of the potential welfare gains. (Chu and Sappington, 2009) analyze how the optimal procurement contract depends on the level of the initial costs of the supplier and the cost of exerting managerial effort to reduce these costs. In a regulatory context, this resembles a situation in which a firm which has already exhausted most of the potential efficiency gains would find it more difficult to keep reducing costs.

(Kopsakangas-Savolainen and Svento, 2010) compares the effect on social welfare of different regulatory schemes, namely price cap and different types of regulatory menus of contracts. Their results show that all the aforementioned regulatory approaches produce gains in social welfare. Nonetheless, the menus of contracts, depending on their implementation, can either obtain higher social welfare improvement or obtain similar levels of welfare gains but a better distribution among consumers and utilities.

Despite the fact that the previous theoretical works show that menus of contracts seem to present important advantages, they have been scarcely implemented in the regulation of electricity distribution. This is presumably due to the fact that menu mechanisms that are in theory superior to other approaches can be too complicated for the agent in charge of its implementation (Rogerson, 2003). (Agrell and Bogetoft, 2003) perform a review of the relevant theory in setting menus of contracts and analyze their potential use to regulate Norwegian distribution companies. Nonetheless, the so-called information quality incentive (IQI) set by OFGEM is one of the few cases in Europe where this type of incentive has been implemented. This incentive was introduced in DPCR4 (2005-2010) to regulate distribution CAPEX.

(Crouch, 2006) provides insights into the design of the regulatory contracts for this period. OFGEM believes that UK's consumers have benefited from the IQI (OFGEM, 2008). Hence, the use of menus of contracts not only has been continued in DPCR5 (2010-2015) but also has it been extended to other cost categories, both OPEX and CAPEX (OFGEM, 2009c). OFGEM's approach is based on a two step process. At the beginning of each regulatory period, DSOs' cost estimation is compared against a baseline determined by the regulator (the methodology will be presented in more detail in Chapter 5). At the end of the period, the actual costs of each DSO are compared against the ex-ante revenue allowances and final revenues are computed following the matrix shown in Figure 3-5.

Ratio of forecast to baseline	**95**	**100**	**105**	**110**	**115**	**120**	**125**	**130**	**135**	**140**
Incentive rate	0.53	0.50	0.48	0.45	0.43	0.40	0.38	0.35	0.33	0.30
Allowed expenditure	98.75	100.00	101.25	102.50	103.75	105.00	106.25	107.50	108.75	110.00
Additional income	3.09	2.50	1.84	1.13	0.34	-0.50	-1.41	-2.38	-3.41	-4.50
Actual expenditure										
90	7.69	7.50	7.19	6.75	6.19	5.50	4.69	3.75	2.69	1.50
95	5.06	5.00	4.81	4.50	4.06	3.50	2.81	2.00	1.06	0.00
100	2.44	2.50	2.44	2.25	1.94	1.50	0.94	0.25	-0.56	-1.50
105	-0.19	0.00	0.06	0.00	-0.19	-0.50	-0.94	-1.50	-2.19	-3.00
110	-2.81	-2.50	-2.31	-2.25	-2.31	-2.50	-2.81	-3.25	-3.81	-4.50
115	-5.44	-5.00	-4.69	-4.50	-4.44	-4.50	-4.69	-5.00	-5.44	-6.00
120	-8.06	-7.50	-7.06	-6.75	-6.56	-6.50	-6.56	-6.75	-7.06	-7.50
125	-10.69	-10.00	-9.44	-9.00	-8.69	-8.50	-8.44	-8.50	-8.69	-9.00
130	-13.31	-12.50	-11.81	-11.25	-10.81	-10.50	-10.31	-10.25	-10.31	-10.50
135	-15.94	-15.00	-14.19	-13.50	-12.94	-12.50	-12.19	-12.00	-11.94	-12.00
140	-18.56	-17.50	-16.56	-15.75	-15.06	-14.50	-14.06	-13.75	-13.56	-13.50
145	-21.19	-20.00	-18.94	-18.00	-17.19	-16.50	-15.94	-15.50	-15.19	-15.00

Figure 3-5: IQI matrix used by OFGEM in DPCR5

Depending on the resulting ratio of DSO's forecast to regulator's baseline, the ex-ante allowed revenues of each DSO is determined (a matrix column is chosen). The higher this ratio is, the higher the ex–ante allowed revenues are, but the lower the incentive rate is. The ex-post evaluation of the costs actually incurred would yield the actual allowed revenues of the DSO computed as the actual costs plus the efficiency incentive (incentive rate times the difference between the allowed and actual costs) and the additional income. This additional income is set in such a way that the scheme is incentive compatible, i.e. it is ensured that DSOs are better off the closer actual costs are to the ones they had initially forecasted, regardless of the ratio of forecast to baseline.

This can be seen in the simplified example presented in Table 3-1, which compares two situations with different DSO's estimation for the same actual expenditures. The situation depicted in the column on the left may correspond to a DSO which inflated its cost estimation in order to get higher allowances. Nonetheless, it can be seen that its revenues would have been higher in case a more accurate forecast had been provided. Consequently, the matrix of menus encourages DSOs to provide accurate expenditure forecasts. This is the reason of the name IQI.

Regulator's estimate [M€]	250	250
DSO's estimate [M€]	300	275
Ratio of forecast to baseline [%]	120	110
Incentive rate [%]	40	45
Additional income [%]	-0.5	1.13
Allowed expenditure [M€]	105% · 250 = **262.5**	102.5% · 250 = **256.25**
Actual expenditure [M€]	275	275
Actual efficiency incentive [M€]	40% · (262.5-275) = **-5**	45% · (256.25-275) = **-8.4375**
Additional income [M€]	-0.5% · 250 = **1.25**	1.13% · 250 = **2.825**
Final remuneration [M€]	275 - 5 - 1.25 = **268.75**	275 - 8.4375 + 2.825 = **269.4**

Table 3-1: Simplified example of application of the IQI matrix

3.3.3.3 Other incentive scheme designs

Previous sections have presented the most common and important designs of incentive mechanisms. Nonetheless, given the current extensive experience applying incentive regulation and the challenges faced by different national regulatory authorities, a much wider range of incentive mechanisms can be found. Hereinafter, these alternative (or additional) incentive scheme designs will be reviewed.

Revenue drivers

Revenue drivers consist of adding one or more terms to the remuneration formula so that this increases proportionally to a certain factor which is to be encouraged. For instance, (Cossent et al., 2009; de Joode et al., 2009; Frias et al., 2009) propose to add DG-related revenue drivers to the revenue cap formula in order to compensate DSOs for DG driven incremental costs and encourage them to connect DG efficiently. The proposed revenue drivers are shown in (3-5).

$$R_n = R_{n-1} \cdot (1 + RPI - X) + \gamma_1 \cdot kW^{DG} + \gamma_2 \cdot MWh^{DG} \quad \textbf{(3-5)}$$

A similar revenue driver is used in the UK where DSOs perceive 1£/kW^{DG} per year during 15 years (OFGEM, 2009c). Furthermore, a revenue driver related to the load growth has been used on a transitory basis in the Spanish regulation. The so-called economies of scale factor that related the increment in distribution revenues per a 1% growth in demand were computed individually for each DSO by using RNMs as described in (CNE, 2007; Mateo et al., 2011).

Input incentives for innovation

Despite the fact that output regulation is generally preferable as the regulation of inputs may lead to micromanagement and adverse selection problems. However, significant steps or changes can be difficult to attain through output regulation. For instance, the implementation of specific input incentives may be needed to achieve a successful implementation of the smart grid paradigm (EEGI, 2010; Cossent et al., 2011a; Eurelectric, 2011).

Input incentives can be designed as direct payment to DSOs in order to undertake specific projects, through a partial or total pass-through of certain costs (these costs would be added to the RAB without subjecting them to efficiency analysis) or by awarding DSOs a higher return on certain investments. Existing incentive mechanisms of these types have been already described in Chapter 2 of this thesis (section 2.4.2) when describing the Finish (pass-through), Italian (differentiated rate of return) and British (direct incentives-LCNF) cases.

Mechanisms to equalise incentives to cut OPEX and CAPEX

One of the main difficulties for a correct functioning of incentive regulation frameworks is how to equalize the incentives perceived by DSOs to reduce costs, regardless of their nature. The existence of frequent price reviews and regulatory measures to address the inherent difficulties in assessing the efficiency of investments in the short-run creates stronger incentives to reduce OPEX over CAPEX, particularly in the last years of each regulatory period. This could lead to extreme sweating assets strategies from DSOs. Due to the existence of tradeoffs between both types of costs this may result in long-term inefficiencies.

In order to mitigate this problem, regulators could implement mechanisms aimed at equalizing the incentives between different types of costs. On the one hand, regulators could accept an accelerated depreciation of assets so that investments are recouped at a higher rate during the initial years. On the other hand, rolling mechanisms can be used to ensure that DSOs perceive the same power of the incentives to reduce costs in all the years of the regulatory period. Thus, the efficiency gains attained in a certain year would be retained for a fixed number of years (usually the duration of regulatory periods). Otherwise, the incentives to cut costs would be stronger at the beginning of the regulatory period than in the final years. OFGEM has implemented both types of mechanisms in

DPCR5 (OFGEM, 2009b). In this case, the accelerated depreciation is known as "fast money" by which 15% of the expenditures is recovered in the same year the investment is made, whereas the remaining 85% "slow money" is added to the RAB and recouped over a period of 20 years. Moreover, a RAB rolling mechanism is used as described in (OFGEM, 2009b).

Asset valuation methods

Regulators can use several methods to value distribution network gross assets in order to determine the RAB. Despite these are not specifically thought of as incentive mechanisms, the incentive properties of each method can be very different. (New Zealand Commerce Commission, 2002) divides the different approaches between revenue-based and cost-based approaches. Revenue-based methodologies value assets according to the expected future income generated by a specific asset. This category comprises methods such as opportunity costs, the discounted cash flow or market transaction value. Nonetheless, it is difficult to apply revenue based methodologies in electricity distribution due to the sunk nature of these investments and the large number of distribution assets which hampers its one by one valuation.

Hence, cost-based valuation approaches are much more commonly used to regulate DSOs[21]. Within this group, two main approaches can be found, although in practice mixed approaches can be followed e.g. using standard costs. These are historical costs and replacement costs. Historical costs are the actual cost of purchasing or installing a specific asset according to the regulatory accounting books. Thus, this method is also known as book value approach. The main advantages of using historical costs are that they ensure cost recovery preventing regulators "clawing back" part of the cost of the assets and that it is based on objective information. However, the use of book values provides scarce incentives to perform efficient investments. Moreover, companies that carried out significant inefficient investments in the past may be benefited as compared to companies that managed to defer network investments due to efficiency gains.

Alternatively, replacement costs can be used. The replacement cost can be defined as the cost of building an asset that would provide and equivalent service at the present time with current technologies. The main advantage of using replacement costs is that it encourages DSOs to invest efficiently as it introduces a kind of yardstick competition. However, regulated firms would be fully exposed to risks associated with technological changes causing large deviations between past and future costs. Replacement costs can be either determined from scratch or by taking existing assets as starting point. The former option corresponds to the new replacement value (NRV) frequently employed in South American countries. This method is preferable when information from the actual assets is scarce or untrustworthy, albeit it requires extensive analytical work to determine the NRV. On the other hand, if the method build on existing assets compute the NRV of existing assets also known as reproduction costs. This approach reduces the risks of deviations between actual costs and allowed revenues, although it is more influenced by inefficient investments made by the firms that the pure NRV and requires detailed information from the firms' assets.

[21] Chapter 5 will describe in more detail the RAB valuation approaches for electricity distribution and discuss their suitability under different circumstances.

3.4 Summary and conclusions

This chapter has built on the previous one by providing further insights into the implementation of incentive regulation in the form of revenue caps. Several alternative remuneration formulas have been presented and discussed. Nevertheless, it has been shown that asymmetries of information create important practical problems when implementing such an apparently straightforward regulatory approach. The major source of difficulties originates from the precise evaluation of what is the efficient level of network investments required to accommodate load growths, replace aged assets or improve quality of service. The intrinsic characteristics of distribution networks, where the number of individual investment alternatives is extremely large, constitute the main for this.

Hence, regulators have to find balanced solutions to several tradeoffs arising from these barriers. In order to achieve this, the effects of information asymmetries can be mitigated and efficiency promoted either through the use of certain tools or through appropriate regulatory incentives. The former group essentially comprises regulatory accounting systems, i.e. standardized system for information gathering, and regulatory benchmarking, which consists in evaluating the efficiency of DSOs by comparing regulated firms among them or with a theoretically efficient comparable firm. On the other hand, the regulatory incentives that can be used for these purposes include, among others, bonus-malus systems and ex-ante/ex-post mechanisms such as sliding scale of profit sharing schemes.

This chapter intends to serve as an introduction of the main concepts that will constitute the basis of the analyses and regulatory proposals presented in subsequent chapters.

Main conclusions:

- Determining the efficient level of network investments constitutes the major difficulty when regulating DSOs
- Information asymmetries can be mitigated and efficiency promoted by means of several regulatory tools and an appropriate design of incentive schemes

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4. Regulatory benchmarking in electricity distribution: a taxonomy of approaches

Chapter 3 mentioned benchmarking as one of the main tools used by regulators to overcome asymmetries of information and promote efficiency. The role of benchmarking is particularly relevant under incentive based regulation where ex-ante/ex-post reviews gained in importance due to the potentially larger deviations between forecasted and actual expenditures that may arise in longer regulatory periods. Therefore, it is important to identify the existing methods that can be applied to assess the behaviour of DSOs so that they can be critically evaluated to determine their suitability in the different situations. Addressing this need, this chapter presents a comprehensive review of the regulatory benchmarking tools used by regulators. In order to facilitate this analysis, a new classification of the different benchmarking methods in the context of energy networks is proposed.

Firstly, a review of the existing proposals to classify benchmarking approaches is presented in section 4.1. Several inconsistencies and gaps were found among these classifications. Therefore, section 4.2 proposes a new and more comprehensive taxonomy of regulatory benchmarking methods. Following the aforementioned taxonomy, section 4.3 describes in detail each one of the benchmarking categories previously identified. Finally, some concluding remarks are provided in section 4.4.

4.1 A review of taxonomy proposals

Several benchmarking methods with different levels of complexity and relying on different brands of knowledge have been developed. Notwithstanding, as it will be shown in this section, there is not a commonly agreed classification of all the different approaches to regulatory benchmarking. The most extensive classification can be found in (Ajodhia, 2005); this is shown in Figure 4-1.

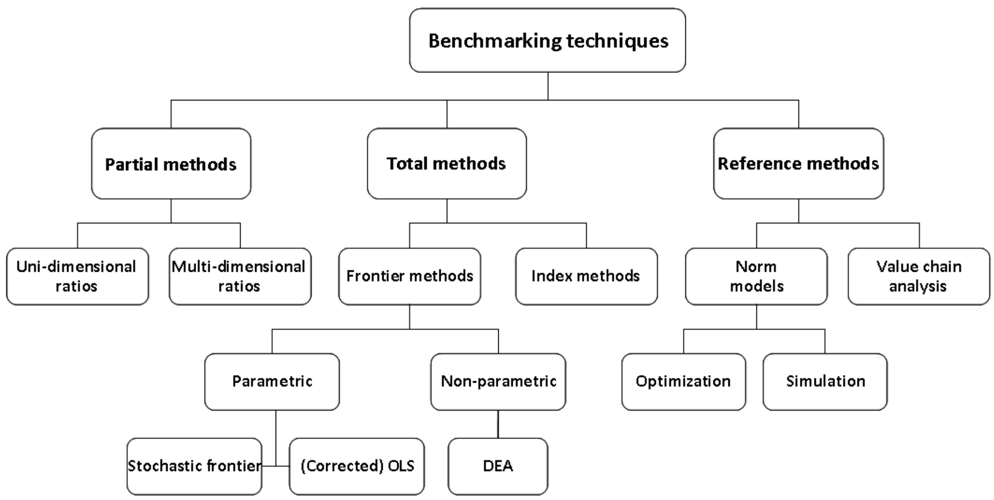

Figure 4-1: Classification of different benchmarking techniques made by (Ajodhia, 2005)

This author firstly mentions benchmarking based on partial methods, which basically consist in calculating certain ratios associated with the performance of the regulated firms. In the case of DSOs, (Ajodhia, 2005) mentioned as examples the energy distributed per employee or total costs incurred per unit of energy distributed. Since the scope of single ratios is very limited, multi-dimensional ratios could be built by combining several uni-dimensional indices through specific weights for each one. Nevertheless, any of these ratios would still provide a partial picture of the firms' performance.

Total methods intend to overcome this disadvantage. The author divides total methods into frontier methods and index methods. Index methods are similar to the previous partial methods, although the ratio computed considers all the inputs and the outputs of the companies, as in the total factor productivity (TFP). On the other hand, frontier methods intend to build an artificial efficient firm (frontier firm) from the information of the costs of actual companies. A frontier firm is one that minimizes its inputs given the outputs or vice versa.

Finally, the last category found in (Ajodhia, 2005) are reference methods. The main difference between frontier methods and reference methods is that the former use as input data from the actual firms, whereas the latter constructs an ideal reference firm through modelling techniques. Within this category, (Ajodhia, 2005) places norm models, which would consist of optimization or simulation models relying on engineering knowledge, and the value chain analysis performed to compare one-to-one the performance of the Norwegian TSO Statkraft with the Swedish TSO Svenska Kraftnät, considering specific operational and environmental factors (Jamasb and Pollitt, 2001).

(Jamasb and Pollitt, 2001) suggest an alternative classification. These authors divide benchmarking techniques into two classes, i.e. frontier benchmarking and mean or average benchmarking. The category named as frontier benchmarking comprises the frontier methods mentioned by (Ajodhia, 2005) and the value chain analysis, which (Ajodhia, 2005) placed under reference methods. On the other hand, mean or average methods includes regression analysis that estimate an average production function, models firms as used in some Latin-American countries, TFP and some kind of sliding scale that includes aspects of yardstick regulation (Jamasb and Pollitt, 2001). In another publication, the same authors additionally refer to norm models as an alternative approach to benchmarking (Jamasb and Pollitt, 2008). Based on these publications, the classification shown in Figure 4-2 has been constructed as the one proposed by these authors.

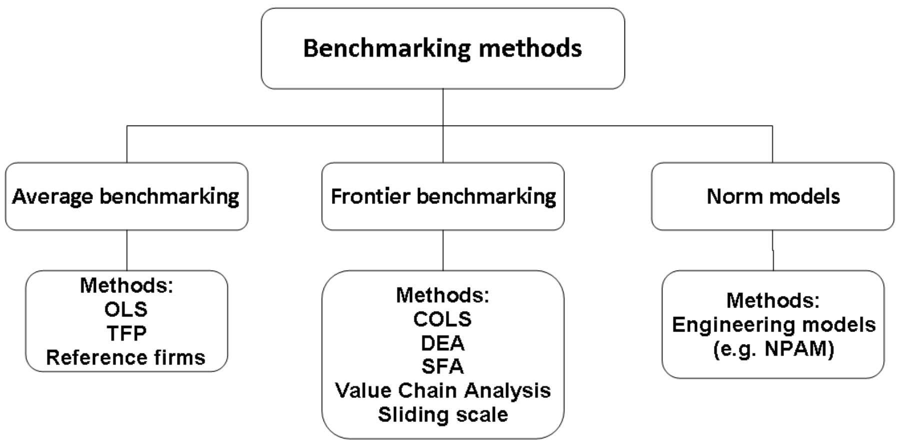

Figure 4-2: Classification of different benchmarking techniques constructed on the basis of (Jamasb and Pollitt, 2001) and (Jamasb and Pollitt, 2008). Own elaboration.

The previous classification broadly coincides with the one used in (Irastorza, 2003). The only differences are that within average benchmarking only partial ratios and ordinary least squares are mentioned (OLS); whereas under frontier benchmarking, (Irastorza, 2003) only mentions corrected OLS (COLS), stochastic frontier analysis (SFA) and data envelopment analysis (DEA). The author makes a reference to engineering models, such as the ones used in Chile and Spain, although these are not discussed throughout the paper.

(Hirschhausen and Cullmann, 2005) propose a classification for airport benchmarking techniques that combines the two ones previously described (Figure 4-3). The partial and multi-dimensional (or total) benchmarking terminology is taken from (Ajodhia, 2005) and is combined with the average and frontier categories by (Jamasb and Pollitt, 2001). Furthermore, the authors include a new parametric frontier method that is not generally considered by other authors in their taxonomies, the modified OLS (MOLS). MOLS constitutes a predecessor of stochastic parametric frontier functions that aimed to limit the influence of outliers on the efficiency results, which was originally proposed in (Schmidt, 1976). Since this classification was made for airport benchmarking and not for energy network companies, reference methods are consequently neglected.

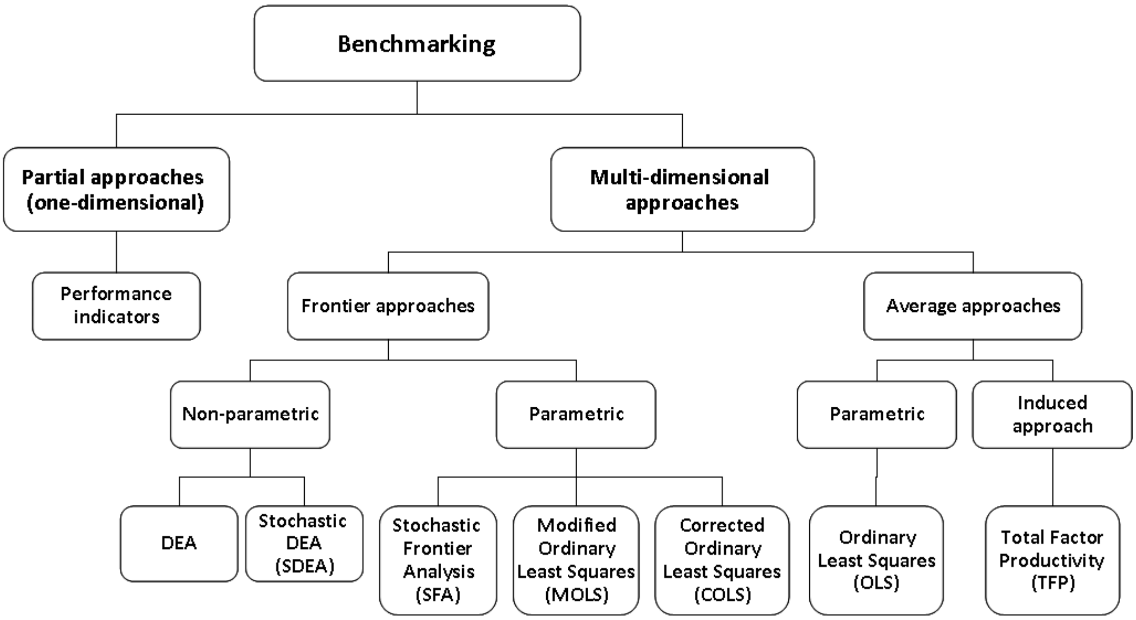

Figure 4-3: Classification of benchmarking techniques given in (Hirschhausen and Cullmann, 2005)

(Farsi et al., 2005) propose a categorisation of benchmarking approaches according to what aspect of the companies' performance is evaluated. As shown in Figure 4-4, according to this criterion, the authors find three groups of techniques: quality, efficiency and productivity benchmarking. Another characteristic that distinguishes this classification from the previous ones is a more detailed analysis of the different approaches to parametric stochastic benchmarking using panel data as opposed to conventional cross-sectional data. Finally, the free disposal hull (FDH) approach is included in the non-parametric frontier methods. This approach has been rarely mentioned by other authors given its infrequent application in electricity distribution. Reference benchmarking methods are not included in this review.

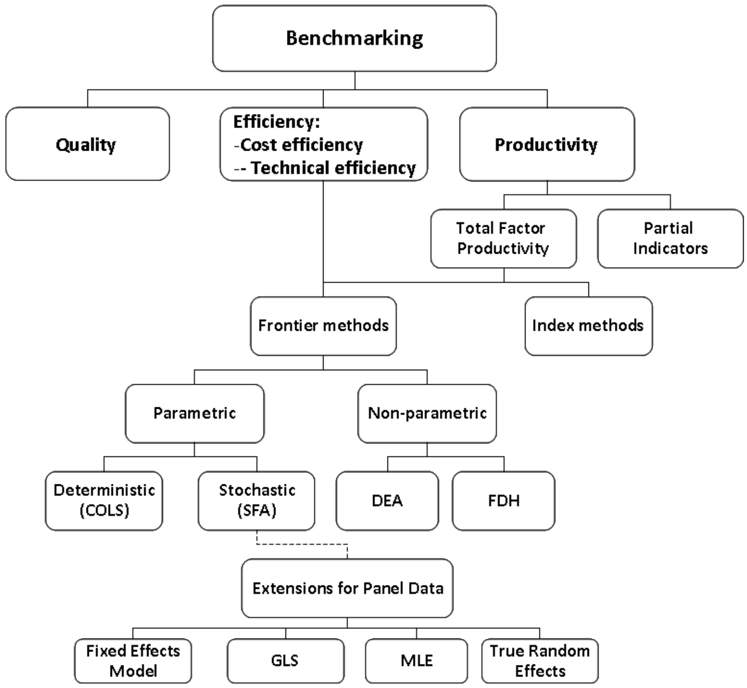

Figure 4-4: Classification of benchmarking techniques given in (Farsi et al., 2005).

All the classifications described until now intended to provide a comprehensive overview of regulatory benchmarking approaches. Nonetheless, some authors have analyzed in more detail specific groups of these benchmarking methods. For instance, (Agrell and Bogetoft, 2003) focus specifically on the techniques referred to as frontier benchmarking by previous authors. As shown in Figure 4-5, the main difference with respect to the previous ones lies in the separation of deterministic and stochastic approaches. Besides frontier methods, these authors mention engineering approaches, albeit these are not included in their classification.

	Deterministic	**Stochastic**
Parametric	Corrected Ordinary Least Squares (COLS)	Stochastic Frontier Analysis (SFA)
Non-parametric	Data Envelopment Analysis (DEA)	Stochastic Data Envelopment Analysis (SDEA)

Figure 4-5: Classification of different benchmarking techniques as defined in (Agrell and Bogetoft, 2003)

Finally, a more in-depth analysis of the different non-parametric approaches to frontier benchmarking can be found in (Kuosmanen, 2001). The taxonomy proposed by this author starts from the observation that conventional formulations of non-parametric frontiers relies on three main assumptions: convexity, monotonicity (free disposability) and constant returns to scale (CRS). These assumptions would be the basis for the DEA with CRS, also named as ray-unbounded convex monotone hull (RCMH). Relaxing the CRS condition would result in the convex monotone hull (CMH) approach, which basically coincides with a DEA model with variable returns to scale (VRS).

Subsequently, relaxing the monotonicity or free disposability constraint, would produce the convex hull (CH). Nonetheless, the author argues that the implications of assuming convexity may be much more relevant in actual applications than monotonicity. Therefore, the monotone hull (MH) or FDH, which relaxes the convexity constraint while maintaining monotonicity, would be more useful. (Kuosmanen, 2001) further mentions some hybrid approaches where the convexity assumption is partially relaxed and introduces the concept of conditional convexity.

	Assumptions		
	CRS	Monotonicity	Convexity
DEA-CRS (RCMH)	X	X	X
DEA-VRS (CMH)	-	X	X
CH	-	-	X
FDH (MH)	-	X	-

Table 4-1: Taxonomy of non-parametric benchmarking methods. Source: (Kuosmanen, 2001). Own elaboration

Several conclusions can be drawn from the previous review. First of all, it is clear that there is not a commonly agreed taxonomy of the different benchmarking approaches that have been applied to electricity distribution companies. The main differences lie in the main criteria to perform the initial sorting into groups. The criteria that have been identified comprise whether partial or total benchmarking is performed, whether DSOs are benchmarked against an efficient frontier firm or an average one or the aspect that is analyzed (quality, efficiency or productivity). However, none of these criteria seems fully sound or adequate. For example, frontier methods, which are commonly placed within total benchmarking approaches, are frequently used to benchmark only operational costs, i.e. to obtain partial benchmarks (Haney and Pollitt, 2009).

Additionally, index methods are typically included within average benchmarking methods. However, the ratios obtained for each firm may be compared against the average of the sector of the best practices across the sector. Hence, it seems that a previous division is required to fully capture all the particularities of the different benchmarking approaches.

Finally, the division into quality, efficiency and productivity benchmarking is quite unclear as significant overlaps exist between the efficiency and productivity categories. In fact, the same authors themselves acknowledge that productivity can be considered as an especial case of efficiency and that the main reasons underlying the differentiation were methodological. Moreover, quality benchmarking, when done by comparison of certain reliability indices (IEEE, 2001), can be considered as a partial indicator of productivity should it be assumed that quality of service is an additional output of distribution companies. Moreover, quality of service can be incorporated to a broader efficiency analysis as in (Giannakis et al., 2005). Since the main purpose of this study was to analyse whether integrating quality of service as an additional variable in DEA would result in significant differences as compared to costs-only benchmarking, this can be hardly considered as a truly distinct branch of benchmarking.

Regarding the techniques included in existing classifications, frontier benchmarking methods are the most widely discussed and applied in the literature. Notwithstanding, certain methods are not always included in the reviews. This seems to be a consequence of that fact that these approaches are rarely applied in practice. For instance, the only applications of FDH to electricity distribution that has been found is (Cullmann and von

Hirschhausen, 2008a; Cullmann and Von Hirschhausen, 2008b) and (ECC, 2006) is the only application of MOLS (Schmidt, 1976) in electricity distribution found. Moreover, the only application to DSOs of probabilistic frontier functions (PFF), originally proposed in (Timmer, 1971), found in this review is that of OFGEM in DPCR4 (OFGEM, 2004). Therein, the COLS frontier was shifted to the upper quartile efficiency level.

Lastly, many authors mention that engineering approaches have been applied in countries such as Sweden, Spain or Chile. However, few additional details or analyses are generally provided. This is presumably due to the fact that, contrary to frontier methods, these models are quite specific to each application. Furthermore, little information is generally made publicly available about the use and results obtained with these models. Consequently, it is unclear where to place them within the proposed classification criteria, thus reference methods are usually placed under a separate category.

4.2 New proposal for classifying benchmarking methods

This section presents a new comprehensive classification of regulatory benchmarking approaches applied in electricity distribution addressing the gaps identified in the previous review. The first issue to be addressed was to determine appropriate classification criteria. As previously discussed, the criteria used previously based on the aspect of the firm that is benchmarked or whether an average or a frontier benchmark is used could be inconsistent. Hence, the taxonomy proposed herein is built according to the inherent characteristics of the techniques used. This taxonomy is depicted in Figure 4-6, together with examples of the techniques included in each category[22].

Following the previous criterion, the main division depends on the level of detail of the inner operations of the firms and the technologies involved that is assumed to be known. Thus, two main categories have been identified. On the one hand, it may be assumed that technology is known and can be reproduced in detail. On the other hand, other approaches see regulated firms as black boxes for which only inputs and outputs can be observed and measured. Accordingly, benchmarking methods would be sorted into:

i. **Black-box benchmarking**: this category comprises all the methods that assume the regulated companies to be black boxes for which only the inputs and outputs are observable. Past information about the actual performance of real companies is used to set comparisons among different firms or against a best-practice firm constructed from the observations of the actual firms. Different techniques can be found in this category, which mainly come from the fields of operations research or econometrics.

ii. **Reference (or white/grey box) benchmarking**: these methods are characterised by building a bottom-up benchmark for the distribution networks and the associated costs of regulated firms. This generally leads to a single benchmark for each company. This bottom-up model requires an in-depth knowledge of the functioning of the sector being subject to regulation. The benchmarks can be constructed either through engineering simulation/optimization models, other non-formalised analyses of the firms' costs and its comparison with other firms operating in similar conditions. In order to do this, it is generally necessary to resort to some experts' or consultants' support.

[22] Sliding scale, considered as an average benchmarking technique in (Jamasb and Pollitt, 2001), has been excluded from this classification because this mechanism (setting the allowed rate of return as an average in the sector) can be considered as a form of yardstick regulation instead of a benchmarking approach.

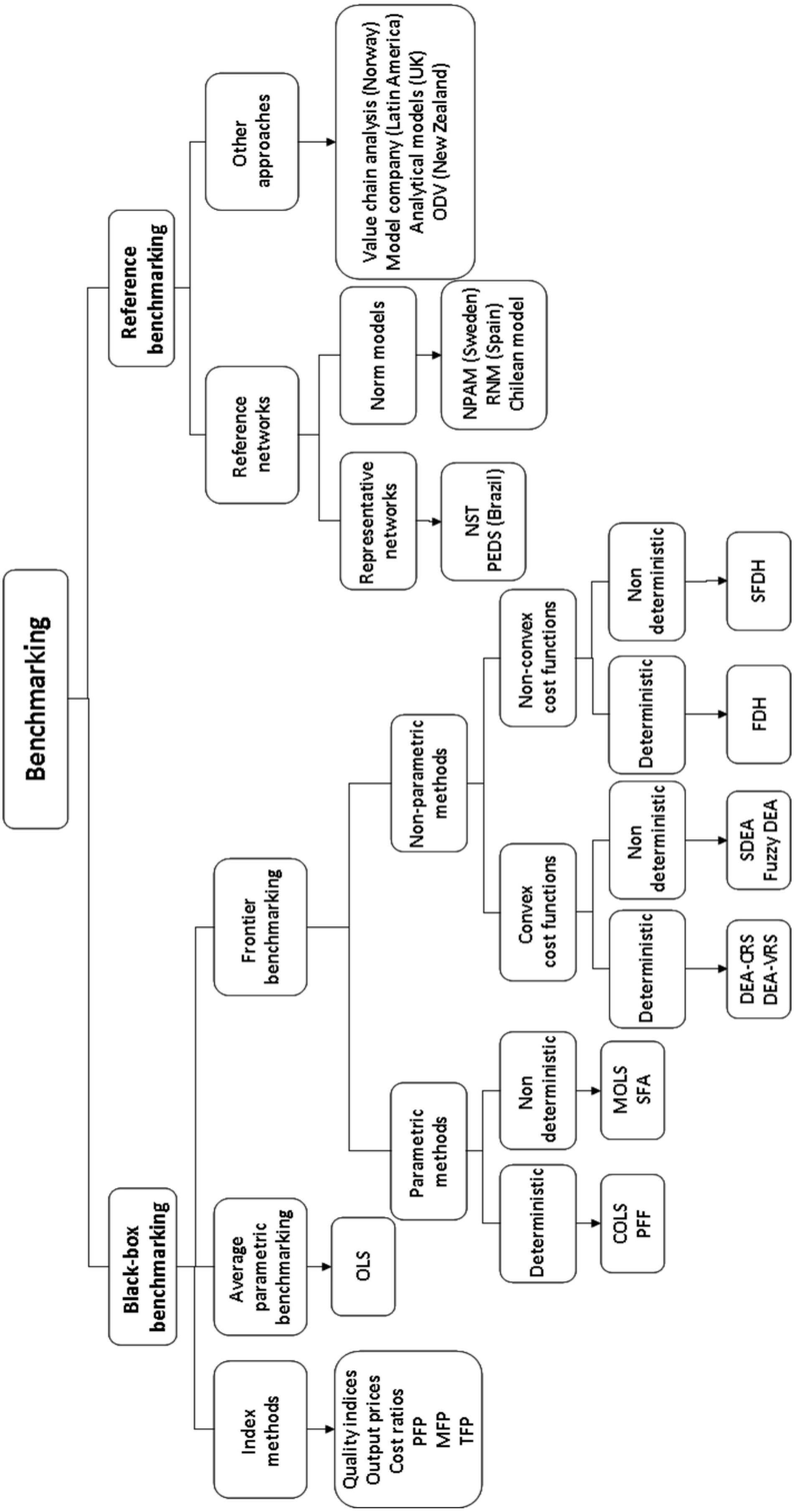

Figure 4-6: Proposed classification of benchmarking techniques

The subsequent subdivisions are more similar to existing classifications. Nonetheless, some changes were deemed necessary. The differentiation between partial and total methods done in (Ajodhia, 2005) has been removed in the proposed classification since practically all of the black-box benchmarking methods can be used to perform a partial benchmarking. For example, it is not uncommon to find regulators that perform frontier benchmarking considering only OPEX, leaving CAPEX outside the efficiency assessment. Moreover, all the partial methods described in (Ajodhia, 2005) are in essence based on the computation of indices or ratios. For instance, the only difference between the partial factor productivity (PFP) or the multi-factor productivity (MFP) and the TFP is whether all or a selection of the inputs of the activity are included in the calculations. Therefore, all these types of benchmarking methods have been included within the single category of index methods.

The remaining black-box techniques have been divided into average parametric benchmarking and frontier benchmarking following (Jamasb and Pollitt, 2001). Despite the fact that the computation of average parametric functions is methodologically very similar to the parametric frontier benchmarking methods, this differentiation has been maintained since this difference presents some important regulatory consequences.

The taxonomy provided in (Kuosmanen, 2001) on non-parametric benchmarking has been partially incorporated. More specifically, convexity assumptions have been included into the classification as this is the one that affects results more significantly. In fact, (Grifell-Tatjé and Kerstens, 2008) argue that the use of non-convex technologies in black-box models may reduce the gap between the models conventionally employed by economists (black-box methods) and engineers (reference methods). On the other hand, the vast majority of applications of non-parametric frontier benchmarking assume free disposability; therefore, this criterion has not been considered. Additionally, DEA models with CRS and VRS are generally used jointly in comparative analyses. Hence, introducing this additional criterion in the classification was not deemed necessary.

The last division performed on black-box frontier benchmarking methods is whether the efficiency frontier is determined deterministically or not (Agrell and Bogetoft, 2003). Note that this division also applies to non-parametric frontier approaches despite the fact that the stochastic parametric approaches (SFA) are much more widely known than non-deterministic non-parametric methods. Application of stochastic DEA models (SDEA) to electricity distribution can be found in (Cullmann and Von Hirschhausen, 2008b; Sadjadi and Omrani, 2008). Applications of other non-deterministic methods such as stochastic FDH (Simar and Zelenyuk, 2011) or fuzzy DEA (Hatami-Marbini et al., 2011) to electricity distribution have not been found in the literature. More detailed taxonomies of very specific techniques such as SFA models with panel data (Farsi et al., 2005) or different fuzzy DEA models (Hatami-Marbini et al., 2011) have not been considered.

Given the wide experience with the application of black-box models to different sectors, and electricity distribution in particular, it is possible to perform quite a detailed classification of the different approaches. However, such an extensive classification cannot be made with reference benchmarking methods because these models tend to be very specific to the sector and context for which they have been developed. This is the main reason why Figure 4-6 includes the countries where each reference benchmarking technique has been applied. Consequently, the level of detail that can be attained for black-box benchmarking classification is much greater than what is possible for the remaining approaches, for which each application is almost unique (although, in principle, the same or similar models could be applied to other countries).

The different approaches to regulatory benchmarking that can be found will be described in more detail in the next section. Special attention will be paid to those that have been applied most extensively to electricity distribution companies, i.e. frontier benchmarking and reference networks. Moreover, a comparative assessment of the strengths and weaknesses of these approaches will be performed, considering the future challenges faced by DSOs and regulators mentioned in the previous chapter.

4.3 Review of benchmarking methods

4.3.1 Black-box benchmarking

Black-box benchmarking techniques intend to asses the efficiency of a firm by comparing its inputs and outputs with those of their peers, i.e. other firms from the same sector. Since the detailed internal functioning of regulated firms is considered unknown, this kind of techniques can be adapted and applied to different sectors by analysing the inputs and outputs of each sector and identifying the most relevant ones. On the ensuing, different black-box benchmarking techniques and its application to regulate electricity distribution companies will be reviewed.

4.3.1.1 Index methods

Index methods for benchmarking broadly consist on obtaining specific ratios that aim at reflecting the actual performance of a company in a specific aspect of its activity. These ratios can be compared with those of similar companies in a specific moment in time or with past information of the same company to assess its evolution over time. The main advantage of index methods lies in its simplicity. However, these ratios only provide a very limited picture of the overall company performance. Therefore, this approach is rarely applied as the main tool to regulate DSOs. Nonetheless, different indices can be used, when together with other indicators, to provide interesting analyses (Houston and Green, 2007). Among the indicators used in regulation we may find prices of outputs, partial measures of costs, measures of the quality of service, PFP, multifactor productivity (MFP), TFP, or level of investments (Houston and Green, 2007).

The TFP is probably one of the most widely used indices, being applied to individual companies, sectors or even countries as a whole. This index measures the efficiency in using of all the inputs to produce the outputs delivered. In case not all the inputs or just a single input were considered, the results will provide a MFP or a PFP index respectively. The TFP allows measuring the variation in the outputs for consumers produced by a firm or set of firms that is not explained by a change in any of the inputs required (OFGEM, 2003). Efficiency improvements are considered one of the major components of the TFP. Nonetheless, technological development causing a shift in the efficiency frontier is relevant too.

The TFP can be estimated through different methods. According to the review presented in (Raa and Shestalova, 2011), there are four main approaches to estimate the TFP: Solow residual, index numbers (Törnqvist or Fisher indices), DEA-based methods (Malmquist index) and Domar aggregation. This index is frequently applied to assess the evolution of productivity over time. Nevertheless, implementing TFP in the regulation of network companies poses several questions related, for instance, with the selection of inputs and outputs, how to value and weight the different inputs and outputs, whether environmental variables ought to be considered, etc. (Essential Services Commission, 2009).

Several examples can be found where some ratios are used for certain regulatory tasks in electricity distribution. A clear example corresponds to the several indices that measure continuity of supply, which are used to provide DSOs with incentives to reduce the number and duration of interruptions. An overview of the many indices that can be used to measure continuity of supply in distribution networks can be found in (IEEE, 2001). Another example of the application of index methods is the use of a multi-dimensional index as an variable in benchmarking analyses, as done by OFGEM in DPCR3 (Pollitt, 2005). In this case, OFGEM used a composite scale variable (CSV) as an output variable in regressions using COLS. This variable intended to measure the influence of exogenous factors on DSOs OPEX and was calculated as a weighted average of the number of customers (50%), the volume of energy distributed (25%) and the length of the network (25%).

Moreover, the PFP has been used to evaluate the evolution over time of the performance of DSOs regarding only OPEX or only CAPEX, instead of considering overall costs. This information can be useful in setting future targets for cost reductions. The PFP has been used, for instance, in the UK (OFGEM, 2003) or Australia (Essential Services Commission, 2009). Finally, the TFP has been quite often used to estimate the frontier shift (productivity improvement due to technological development) and catch-up rates (productivity growth of inefficient firms) to be considered when computing efficiency factors (X-factors in RPI-X regulation) for DSOs. This can be done through the Malmquist index, which allows decomposing the TFP into frontier shift and catch-up effect. Additionally, TFP can be used to assess the efficiency improvements of DSOs over time, generally through Törnqvist or Malmquist indices. A summary of studies where this approach has been used for DSOs can be found in (ECC, 2006). Some further examples are mentioned in (Jamasb and Pollitt, 2001).

4.3.1.2 Average parametric benchmarking

The purpose of average benchmarking is to compare the performance of a company with a measurement of the average performance across all the companies within the sector. The benchmark in this case is obtained through regression analyses that yield an analytic expression of the production function of an average firm.

This type of methodology basically consists of defining the input and output variables, gathering the corresponding information related to the regulated firms and fitting a function relating the inputs and the outputs that matches the observed data. This average cost or production function can be fitted through any regression method, albeit the most commonly used method is the ordinary least squares (OLS). Nonetheless, some variations of this regression method and estimators could be applied such as the least absolute deviations (LAD).

This approach is not generally used in practice as a regulatory benchmarking tool. Nonetheless, the computation of an average cost/production function is essential in any parametric frontier benchmarking method. This will be described in more detail below. Furthermore, the analysis of the resulting average functions may yield some interesting results concerning the companies being evaluated. Several papers estimating average cost or production functions for electricity companies with different purposes can be found in the literature.

Some of these studies were performed for vertically integrated electric utilities in order to estimate the effect on efficiency of different forms of private ownership (Dan Berry, 1994) or to assess the existence of economies of density and size (Roberts, 1986). Several other studies focus specifically on electricity distribution. A short review can be found in (Filippini and Wild, 2001). Nonetheless, the same authors acknowledge that electricity supply has been rarely separated from the proper network activities. Thus, (Filippini and Wild, 2001), despite the fact that the firms analysed perform both activities, exclude the costs of purchasing electricity from the benchmarking analysis to focus on distribution costs. The authors suggest that their results could be used by regulators for distribution network pricing based on yardstick regulation. Furthermore, it is found that of environmental factors such as consumer density or land types can have a significant impact of distribution costs.

4.3.1.3 Frontier benchmarking

Frontier benchmarking methods construct a cost function that represents an efficient or frontier firm from the observation of the actual performance of existing utilities. The distance of each firm to this frontier cost function measures the degree of inefficiency of each firm. Broadly speaking, the closer a single firm is to the frontier, the more efficient it will be. The frontier can be built either through econometrics (parametric or statistical benchmarking) or through operations research models (programming or non-parametric benchmarking).

4.3.1.3.1 Programming[23] or non-parametric techniques

Non-parametric benchmarking methods originated in the field of management science and operational research building on the ideas originally presented in (Farrell, 1957; Farrell and Fieldhouse, 1962). The main purpose of these initial developments was to provide an estimate of the efficiency of firms in an industry or any other productive organization considering all the inputs overcoming the drawbacks of index methods (Farrell, 1957). The main contributions of this seminal work were the proposal of a measure of productive efficiency and the concept of production frontier. The main advantage of non-parametric benchmarking lies in the fact that they do not require restrictive assumptions over the production function as in parametric approaches.

Two main techniques for non-parametric benchmarking can be found: DEA and FDH. The main difference between both approaches is whether convexity of the production function is assumed. Nonetheless, several variations of these two models can be found in the literature. Hereafter, non-parametric benchmarking methods and their characteristics will be described in more detail.

DEA is the most commonly applied form of non-parametric benchmarking. The DEA model was originally proposed by (Charnes et al., 1978)[24]. The authors defined efficiency as the ratio of weighted sum of the outputs over the weighted sum of inputs. Thus, an efficient firm or decision making unit (DMU) would be one which cannot further reduce its inputs for the same outputs (input oriented DEA) or which cannot produce more

---

[23] Herein, programming refers to the fact that these methods require solving an optimization problem. Nonetheless, parametric problem generally require solving a minimisation problem as well to perform regressions, for example to minimise the sum of the square of the deviations or the sum of the absolute deviations. Because of this, some authors sometimes refer to parametric frontier methods as programming methods as well. Therefore, the term non-parametric is used hereinafter in order to avoid confusions.

[24] Interestingly, the authors stated that their approach was focused on decision making by not-for profit organizations rather than firms. However, numerous subsequent applications have applied this method for comparing efficiency across different firms in the same sector.

outputs with the current combination of inputs (output oriented approach). In electricity distribution, an input oriented approach is generally preferable as DSOs generally have limited capabilities to modify their outputs (e.g. energy delivered or number of customers) due to the obligation to supply demand and, consequently, regulators focus on promoting a reduction of the inputs, i.e. mainly costs (Jamasb and Pollitt, 2003; Estache et al., 2004; Kinnunen, 2005).

DEA constructs a piecewise linear convex hull that envelops all the observed points and that contains all the efficient firms. Free disposability, or strong disposability, is assumed. This means, for example, that inputs can be reduced at no cost. Subsequently, each firm is compared against an efficient firm that is constructed as a linear combination (in terms of inputs and outputs) of the firms included in the data. This resembles a Pareto front composed by all the firms that present the minimum value of at least one input/output ratio.

The frontier is constructed by solving a linear optimisation problem for each regulated firm. An input oriented linear formulation of the DEA problem is shown in (4-1)[25], where x and y are the input and the outputs respectively, θ_0 is the efficiency of the firm and the λ parameters are the weights of each DMU in the efficient firm with which the DMU under evaluation is being compared. The parameters i, r and j represent the number of inputs, outputs and DMUs respectively.

$$
\begin{aligned}
& \min \theta_0 \\
& s.t. \\
& \theta_0 \cdot x_{i_0} - \sum_{j=1}^{n} \lambda_j \cdot x_{ij} \geq 0; \quad \forall i \\
& -y_{r_0} + \sum_{j=1}^{n} \lambda_j \cdot y_{rj} \geq 0; \quad \forall r \\
& \lambda_j \geq 0 \quad \forall j
\end{aligned}
\tag{4-1}
$$

The previous model implicitly assumes that all companies operate at CRS. Thus, the results would comprise both the technical inefficiency and any possible scale inefficiency. (Banker et al., 1984) proposed an alternative formulation of the problem in order to account for the fact that the level of productivity at the most efficient level may not be attainable at other scales, i.e. bigger or smaller companies. This is done by adding the constraint shown in (4-2) to the optimisation model[26].

$$
\sum_{j=1}^{n} \lambda_j = 1; \quad \forall j \tag{4-2}
$$

The results of this new formulation with VRS would yield the pure technical efficiency of the firms, excluding scale inefficiencies. The results of the models can be compared in order to determine whether companies are operating at efficient levels of scales and to measure the gains from mergers and acquisitions. When used in benchmarking, VRS assumes that the size of the utilities cannot be controlled by them and thus inefficient

[25] This linear formulation was proposed by (Charnes et al., 1978) as an equivalent problem to a fractional non-linear optimisation problem. Sometimes, the dual to the formulation presented herein is solved. Nonetheless, this approach is generally preferred due to its computation advantages.

[26] The resulting model would correspond to a CMH model where the monotonicity and convexity properties remain, but the condition on CRS has been relaxed.

firms are only compared to those of similar size, whereas CRS implicitly assumes that companies may change their size to become more efficient.

The convexity assumption inherent to DEA may have relevant consequences. Some authors argue that actual production functions are non-convex, mainly due to indivisibilities in the inputs; for example, lumpiness of investments (Cherchye et al., 2001; Grifell-Tatjé and Kerstens, 2008). These authors state that imposing convexity assumptions on technology may be overestimating the firms' inefficiencies (Briec et al., 2004). Hence, non-parametric benchmarking allowing for non-convex technologies is deemed superior to DEA by these authors.

(Deprins et al., 1984) firstly proposed a non-parametric method that did not rely on convex technology called FDH. FDH develops a non-convex hull which contains all the non-dominated solutions. Such a hull would be located within a DEA frontier obtained from the same data. Therefore, FDH would generally result in higher efficiency rates for the firms analysed.

The optimization problem that yields the efficient rates according to the FDH approach is a modified version of the DEA-VRS problem. An additional constraint imposing that the lambda variables are binary variables is set (4-3). This means that each firm is compared against a real firm which dominates it instead of a hypothetical convex combination of actual firms.

$$\lambda_j \in \{0,1\}; \quad \forall j \tag{4-3}$$

Figure 4-7 depicts the frontiers obtained by each of the three non-parametric benchmarking methods mentioned, i.e. DEA-CRS, DEA-VRS and FDH, for a simple case with one input and one output. Letters A to F represent actual observations of DMUs, whereas B', B'' and B''' represent the intersection of a radial distance function for DMU B with the different frontiers obtained. Several observations can be made:

– The number of efficient firms increases as the assumptions on CRS and convexity are relaxed: 1 of 6 efficient firm in DEA-CRS (firm D), 3 of 6 efficient firms in DEA-VRS (firms A, D and F) and 5 of 6 in FDH (all firms but B).
– Similarly, the efficiency rate of an inefficient firm increases as more conditions are relaxed. For example, the efficiency rate of firm B would be the ratio OB'/OB for DEA-CRS, OB''/OB for DEA-VRS and OB'''/OB for FDH.
– The frontier in DEA-CRS comprises the firms with the lowest input to output (x/y) ratio, i.e. those using the minimum amount of inputs for the same output. On the other hand, the frontier in DEA-VRS envelopes the firm with the minimum input to output ratio and which have a similar level of output. Finally, the FDH frontier contains all the non-dominated firms, i.e. those firms for which there is not any other that produces more output with the same input or for which there is no other firm using more inputs for the same output.

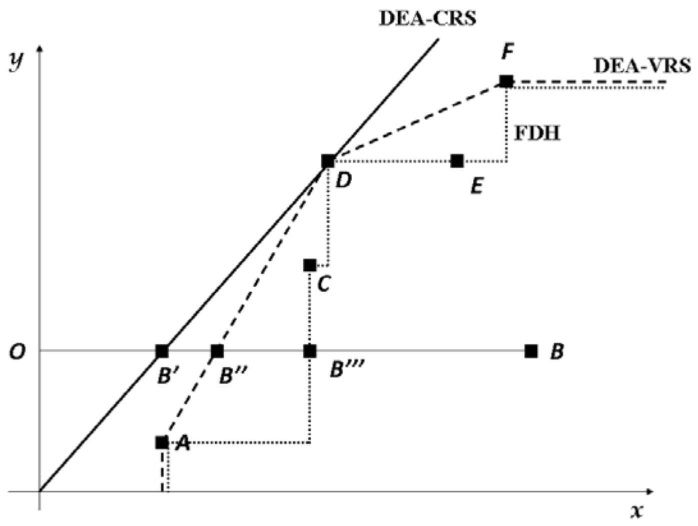

Figure 4-7: Comparison of non-parametric frontier benchmarking techniques

The selection of variables is essential to adequately reflect all relevant parameters affecting the performance of regulated firms and avoid allocating the effect of a significant variable to inefficiencies. However, increasing the number of variables would make it easier to any firm to be closer to the frontier. An alternative way of saying this is that increasing the number of firms whilst maintaining the number of variables would decrease the mean efficiency obtained (Zhang and Bartels, 1998). The collorary of this is that the number of DMUs must be sufficiently large in order to ensure the robustness of the results obtained with non-parametric frontier benchmarking. Moreover, this number should be higher as more variables are taken into account in the analyses. Otherwise, either some potentially relevant variables should be left out or dimensionality problems could arise.

There are no strict rules to determine the optimal number of firms and/or variables. Notwithstanding, several authors (e.g. (Edvardsen and Forsund, 2003; Agrell and Bogetoft, 2007)) refer to the empirical guideline in this respect proposed by (Cooper et al., 2000). This guideline states that the number of DMUs or observations must be higher than three times the sum of the number of inputs and the number of outputs.

Standard non-parametric benchmarking methods have been found to present several shortcomings in their application. Consequently, numerous variations to the basic formulations discussed above have been developed to overcome these limitations. The main variations comprise the following issues: inclusion of environmental variables, using alternative types of distance functions to compute efficiencies, set comparisons among frontier firms (supper efficiency), use of bootstraps to perform statistical analyses or the use of stochastic or fuzzy methods to mitigate the effect of outliers. Most of these variations have been developed for DEA, albeit, in principle, any of these variations could be applied to any of the approaches shown above. The main variations found in the literature are presented in more detail in annex A, section A.1.

Concerning electricity distribution, DEA is much more frequently applied than FDH both in academic papers and by regulators. In fact, FDH has not been used by any of the experiences reported in the reviews found in the literature (Jamasb and Pollitt, 2001; Agrell and Bogetoft, 2003; Farsi et al., 2005; Haney and Pollitt, 2009). Moreover, empirical studies do not generally apply the more advanced developments reviewed above; see, for example, (Pahwa et al., 2003), (Hirschhausen et al., 2006) or (Kinnunen, 2005). This is presumably due to the fact that conventional DEA formulations are much easier to implement. These studies generally place the focus on the selection of input and output variables, the identification of sources of inefficiency, the influence of certain environmental variables (generally without correcting the efficiency estimates), the existence of returns to scale or the comparison with parametric approaches.

Notwithstanding, applications of some more advanced methods can be found. For instance, bootstrapping is used in (Sanhueza et al., 2004) or SDEA is applied in (Sadjadi and Omrani, 2008). Moreover, (Simab and Haghifam, 2010) propose an integrated approach that combines a screening stage to cluster the initial set of firms into comparable groups to account for environmental variables, a principle components analysis to identify the relevant inputs and outputs, a filter to remove outliers, a DEA analysis and a bootstrap correction.

Despite the fact that the aforementioned reviews do not report any application of FDH to the electricity distribution sector, a few examples can be found. (Cullmann and von Hirschhausen, 2008a) apply both DEA and FDH, bootstrapping the DEA results, to perform an international benchmarking of eastern Europe distribution companies and assess the benefits of privatisation in those countries. The same authors apply DEA, SDEA, FDH and SFA to a sample of Polish electricity distribution utilities in order to evaluate the change in efficiency after liberalization in Poland and assessing potential gains in economies of scale from mergers in (Cullmann and Von Hirschhausen, 2008b).

4.3.1.3.2 Statistical or parametric techniques

Parametric frontiers originated as a result of applying econometric techniques to the estimation of production frontiers overcoming certain shortcomings of the linear-programming approach proposed by (Farrell, 1957). According to (Aigner and Chu, 1968), the main drawbacks in Farrel's approach were that statistical analyses on the results could not be performed, assumptions on returns to scale were required and some production functions could not be modelled[27].

The main steps involved in the estimation of a parametric frontier are: i) assume a certain parametric specification for the production function of the sector under analysis, ii) perform regressions with the data corresponding to the actual firms in order to obtain a function representing the average behaviour in the sector, iii) shift the average function to the frontier on the basis of the best observed behaviour across the firms (translation movement) and, if necessary, different assumptions on the probability distribution function of the residuals (in stochastic models), and, finally, iv) estimate the efficiency scores for each firm according to their distance to the frontier obtained in the previous step. Hence, the parametric frontier methods necessarily require applying some kind of the average function methods described in Section 4.3.1.2.

Hereinafter, a review of the main approaches to parametric frontier benchmarking will be presented. For a more in-depth review, the reader is referred to (Green, 2008).

Regression methods had been widely applied to compute average production functions, but (Aigner and Chu, 1968) constitutes the first application of econometrics to the estimation of frontier production functions, in this case in the primary metal industry of the US, where the deviations from this function were interpreted as inefficiencies. The initial proposal by (Aigner and Chu, 1968) was to add the deviation of the best observed

[27] Cost functions that conform to the law of variable proportions, i.e. the marginal benefit of increasing one of the factors of production decreases from a certain point, are provided as an example by the authors.

performance among firms to the average function obtained by means of ordinary least squares (OLS) regressions. Thus, after obtaining the production (or cost) function, the frontier would be obtained by adding the positive (or negative) estimated residual (Bottasso and Conti, 2011). Consequently, all the residuals would be negative (or positive) but the one corresponding to the most efficient firm. The efficiency score for each firm would be computed by measuring the corrected residuals. This method was subsequently known as corrected ordinary least squares (COLS).

COLS is a simple approach that allows the modeller to perform statistical inference on the variables and the results obtained. However, as any other parametric method, relies on assumptions about the functional form of the frontier. Moreover, the results greatly depend on the most efficient firm, which makes it very sensitive to outliers, and does not account for statistical noise or measurement errors. Consequently, the whole estimated residuals are considered as inefficiencies, thus inefficiency scores would tend to be over-estimated.

In an attempt to overcome some of the shortcomings of the deterministic frontier functions obtained by the COLS method, (Timmer, 1971) proposed the use of so-called probabilistic frontier functions. This basically consists in assuming that a certain percentage (P) of the observations lie beyond the frontier, i.e. the frontier is shifted until the percentage (100-P) of firm is enveloped by the frontier. However, the assumption that the fact that some firms lie beyond the frontier is due to measurement errors may not hold. Additionally, the selection of the percentage P is made arbitrarily without adequate justification (Aigner et al., 1977).

Therefore, in order to provide the parametric estimation of frontier function with some statistical basis, (Schmidt, 1976) proposed to assume that the disturbance term in the estimated frontier function followed a specific one-sided probability distribution. The work of (Schmidt, 1976) originated a method known as modified OLS (MOLS). The main difference is related to the constant that is added to the OLS function in order to obtain the frontier function and the efficiency estimates. Instead of adding the largest residual, an estimate of the true expected value of the inefficiency of firms is added to the OLS function. Schmidt's proposal is explained in more detail in annex A, section A.2.

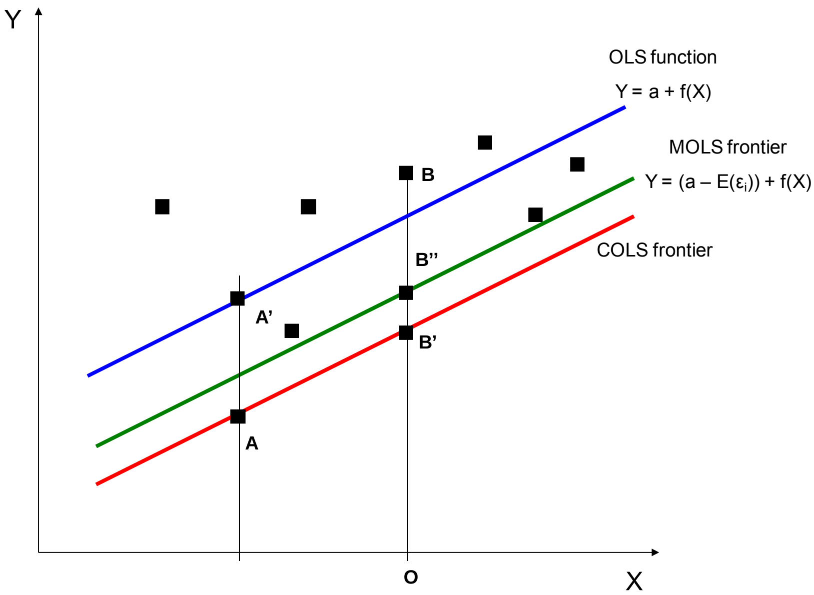

Figure 4-8: Comparison of the COLS and MOLS benchmarking methods

Figure 4-8 displays the OLS average function together with the COLS and MOLS frontier functions for a simple single-input and single-output case. In COLS, the average function obtained by OLS regressions is shifted by adding the distance A'A, being A the firm with the largest residual, to obtain the COLS frontier. In this example, the efficiency score for the inefficient firm B would be computed as the ratio OB'/OB (Jamasb and Pollitt, 2003). On the other hand, the ratio OB''/OB would provide the MOLS efficiency score for the inefficient firm B in Figure 4-8. The use of MOLS does not ensure that all firms are enveloped by the frontier. Consequently, efficiency scores do not necessarily lie in the range of 0-1, as it would be the case of firm A.

(Aigner et al., 1977) suggested that the regularity conditions required for ML estimation are violated in MOLS. Therefore, they deem necessary to consider a more reasonable structure for the error term than just a one-sided distribution. Consequently, they proposed decomposing the error term in two separate components: one symmetrically distributed that accounts for the statistical noise in the data and another one following a one-sided distribution that would represent the inefficiencies, as shown in (4-4). (Aigner et al., 1977) named this frontier function as stochastic frontier, and the method is widely known nowadays as stochastic frontier analysis (SFA).

$$\varepsilon_i = v_i + u_i \tag{4-4}$$

The term v_i in (4-4) represents the symmetric noise, generally assumed to follow a standard normal distribution. On the other hand, the term u_i corresponds to the one-sided component, and is generally modelled through a half-normal or an exponential distribution. This yields an additional advantage of SFA over MOLS and COLS, which is that the variances of both components can be estimated, thus providing a measure of their importance. Note that in this case, contrary to MOLS, the efficiency scores will all lie in the range 0-1 as the efficiency is now measured taking into account the symmetrical component of the error term (v_i). This means that the efficiency of each firm is measured with respect to a distinct frontier function, being the difference among them a translation according to the symmetrical error component for each firm. As a consequence, SFA scores tend to be higher than those of COLS. Nonetheless, some inefficiency can be wrongly allocated to noise.

(Meeusen and Van Den Broeck, 1977) independently developed a similar model to that of (Aigner et al., 1977), which they named composed error model. The authors proposed decomposing the disturbance term into an efficiency measure and what they called a "true error term". This paper is generally considered nowadays to be, together with (Aigner et al., 1977), the origin of SFA.

Parametric frontier benchmarking models face similar problems to those of non-parametric methods with regard to factors that cannot be controlled by regulated firms, such as environmental variables, but may be considered as inefficiencies by benchmarking models. (Coelli et al., 1999) identifies two main approaches for considering environmental variables in parametric benchmarking. On the one hand, it can be assumed that these variables influence the shape of the production function. Thus, environmental factors would be included in the regressions and the technical scores obtained would include their effect. Sometimes, this can be done with dummy variables to take into account or measure the influence of issues such as ownership (public versus private), location (national or foreign), etc. On the other hand, other studies assume that the environmental variables affect the efficiency scores, i.e. the distance to the frontier function, but not the frontier function itself.

The latter group comprises the models based on panel data, i.e. not only observations from different firms but also observations for the same firm over time. Panel data models are based on the observation of the efficiency of firms over time in order to distinguish between true inefficiency and heterogeneity across firms. In order to do this, it is assumed that error terms are dependent across observations as some observations may belong to the same firm in different moments in time. There are several models relying on the use of panel data, which differ in the assumptions on the variation over time of inefficiencies, on the probability distribution of the inefficiency related error component and the independence between the inefficiency and the regressors. An extensive review can be found in (Green, 2008). Nonetheless, panel data models can be broadly categorised in two groups:

i. **Fixed-effects models**: these models assume that heterogeneities are constant over time and correlated with the regressors (independent variables). Their main shortcoming is that they tend to consider as inefficiency effects that vary among firms but not among time, i.e. time-invariant firm-specific heterogeneity. The first application of a fixed-effect can be found in (Schmidt and Sickels, 1984).

ii. **Random-effects models:** contrary to the previous models, random-effects models assumed that heterogeneities are not correlated with the independent variables. These models were firstly applied by (Pitt and Lung-Fei, 1981).

The use of parametric frontier benchmarking is mainly limited to COLS and, specially, SFA. MOLS and PFF models are rarely applied to electricity distribution companies. Concerning electricity distribution, COLS is hardly applied in academic/research papers. One of the rare examples is that of (Jamasb and Pollitt, 2003). Nonetheless, several regulators apply this technique presumably because of its simplicity. An example of the implementation of COLS to regulate DSOs is that of OFGEM in the UK for DPCR3, which is described in (Pollitt, 2005). Additionally, (Agrell and Bogetoft, 2003) report the use of COLS to regulate electricity distribution in Denmark, and (Haney and Pollitt, 2009) report its use by regulators in Austria and Estonia.

Notwithstanding, SFA is the most commonly applied parametric frontier benchmarking method both in academic/research papers and in actual regulatory practice. For instance, SFA has been applied with regulatory purposes in Austria, Australia (New South Wales), Finland, Norway, Portugal and Sweden (Jamasb and Pollitt, 2001; Agrell and Bogetoft, 2003; Haney and Pollitt, 2009; Cossent et al., 2011a). On the other hand, SFA has been applied in several research papers with different purposes such as evaluate technical efficiency of firms within a country (Filippini et al., 2004), assess adequate returns to scale (Filippini et al., 2004; Hirschhausen et al., 2006), measure the effects of privatisation on technical efficiency (Pérez-Reyes and Tovar, 2010), test for differences according to geographical areas (Hirschhausen et al., 2006), compare the efficiency scores obtained with different frontier methods (Jamasb and Pollitt, 2003) or compare the results obtained by using cross-sectional data or panel data methods (Burns and Weyman-Jones, 1996). Some additional studies applying SFA were referenced in (Jamasb and Pollitt, 2001).

Incorporating panel data into SFA models when analysing electricity distribution firms has become common since (Burns and Weyman-Jones, 1996) analysed the regional electricity companies of England and Wales with a random-effects model. Studies can be found for several countries including Finland (Kopsakangas-Savolainen and Svento, 2008; Kopsakangas-Savolainen and Svento, 2011), Switzerland (Farsi and Filippini, 2004; Farsi et al., 2005; Farsi et al., 2006) or the US (Lowry et al., 2005). Even comparative studies between different countries can be found in the literature (Hattori, 2002; Hattori et al., 2005).

4.3.1.3.3 General issues in frontier benchmarking

Previous subsections have described in detail the different approaches to frontier benchmarking and their applications in electricity distribution networks. All these methods present some common characteristics that derive from the fact that they all rely on the concept of frontier production/cost function. There are some further considerations to be made that affect all types of frontier benchmarking techniques. These are addressed below.

One of the first questions that have to be answered in frontier benchmarking is what is to be benchmarked. As mentioned previously, some authors place frontier benchmarking methods within a total benchmarking (Ajodhia, 2005) or multifactor benchmarking (Farsi et al., 2005) category. This is because these methods have the potential to benchmark the DMUs or firms as a whole. In regulatory benchmarking, this can be translated as benchmarking all the firms' costs or TOTEX.

However, this is not necessarily the case as revealed, for instance, by the survey carried out by (Haney and Pollitt, 2009) with answers from 43 regulators for gas and electricity transmission and distribution networks. In fact, their results showed that most regulators performed benchmarking analysis only for OPEX, albeit it is true that almost as many benchmarked TOTEX. CAPEX-only benchmarking is clearly the least common approach. This is due to the intrinsic difficulties in benchmarking CAPEX due to the heterogeneity among firms. This is even more relevant for network companies, as opposed to banking or dairy farms, as geography, climate, population density and other environmental variables greatly affect the amount and type of investments that are required.

When OPEX and CAPEX are analysed separately, it is unclear how to best combine these two efficiency estimates. Creating separate incentives for each type of cost category should be avoided in order to encourage DSOs to exploit potential tradeoffs between OPEX and CAPEX or avoid other problems such as capitalisation of OPEX. Moreover, each DSO may follow different strategies regarding the tradeoffs between OPEX and CAPEX. Thus, regulators should avoid requiring every firm to get closer to the most efficient in OPEX and in CAPEX simultaneously as this may be unfair.

The next step in a benchmarking exercise, besides choosing the type of technique to adopt, would be to select the inputs and outputs. In electricity distribution, the variables considered tend to vary significantly from one study to another. What is more, the review presented in (Jamasb and Pollitt, 2001) shows that the same variable may be considered as an input for some authors, whereas it can be an output for others. Notwithstanding, it is true that any measure of costs, such as OPEX or TOTEX, is generally considered as an input, whereas the number of customers or the amount of energy distributed are typically outputs. Furthermore, availability of the data is quite frequently a limitation factor. Therefore, it is not uncommon to find studies where actual information of the costs of DSOs is not available and the authors use some other variable as a proxy. For instance, the number of employees or the volume of energy losses are sometimes used as a proxy for OPEX, whereas the transformation capacity installed or the length of the network are used as a proxy for CAPEX (e.g. (Blázquez-Gómez and Grifell-Tatjé, 2011)).

An additional issue to consider when selecting the model variables is that it should be ensured that the relevant variables needed to adequately capture the conditions faced by actual firms have been taken into account. However, the number of variables should not be too large in order to avoid dimensionality problems that make results insignificant. An excessive number of variables may artificially increase the number of frontier firms and increase overall efficiency scores in non-parametric methods (assuming that the sample size remains constant). In parametric methods, this could introduce problems of multicollinearity or result in the inclusion of insignificant variables.

Moreover, as mentioned before in this chapter, a sufficient number of observations is essential to attain significant results. However, some countries may have a low number of firms within a given sector, e.g. electricity distribution. In these cases, performing international benchmarking has been pointed out as a potential solution[28] (Edvardsen and Forsund, 2003; Jamasb and Pollitt, 2003). However, important barriers may hamper the implementation of international benchmarking. Data gathering is complicated due to the lack of standardisation in regulatory accounting systems. Moreover, the use of different currencies or the fact that price or wages levels may differ across countries requires a careful processing of the input data before carrying out any actual benchmarking. Finally, the fact that the timing of price reviews differ on a country basis may hamper international benchmarking due to the dissemination of data and results (Jamasb and Pollitt, 2003). In order to overcome these difficulties, most authors agree that international cooperation and coordination among regulators to develop standardised data sets is required (Estache et al., 2004; Jamasb et al., 2008).

Despite the clear benefits of international benchmarking, the problem of heterogeneity across firms, which already made it difficult to benchmark CAPEX, may worsen as a result of including firms from different countries in the data set. Several issues related to the national orography, climate or regulation may influence the results unless this is taken into account. For example, in some countries DSOs may be obliged to build all their lines underground due to environmental regulation or may have to connect significantly higher amounts of DG because of distinct energy policies. Therefore, accounting for heterogeneity and environmental variables becomes even more relevant in this context. Previous sections have already described the different alternatives to do this both in non-parametric and parametric frontier benchmarking.

Up to this point, regulatory benchmarking has been mainly addressed as a static phenomenon. However, regulation is a dynamic activity. Therefore, it might be interesting to assess the evolution of efficiency over time. The simplest way to do this would be to compare the static efficiency scores obtained by analysing each period of time separately. Nonetheless, in order to do this, there are more advanced methodologies that rely on the use of panel data instead of mere cross-sectional data. The use of the time information included in the data is performed differently in parametric and non-parametric methods:

– In non-parametric models, Malmquist indices computed with the static efficiency results can be used to measure the productivity change over time. Furthermore, efficiency gains can be decomposed into changes in scale efficiency, pure technical efficiency and the frontier shift. The methodology and examples of application can be found in (Forsund and Kittelsen, 1998; Jamasb et al., 2008; Ramos-Real et al., 2009).

[28] A different alternative for these cases would be the use of reference benchmarking. This will be further discussed in subsequent sections.

Another possibility would be to use data from several years at a time following a moving time-window analysis. For example, (Blázquez-Gómez and Grifell-Tatjé, 2011) apply a super-efficiency DEA model to Spanish DSOs in the period 1988-2002, which they divide into three sub-periods following changes in regulation. However, this method is subject to trial and error in the arbitrary selection of the window width (Estache et al., 2004).

– In parametric approaches, the most common approach to measure the evolution of (in) efficiency over time is through panel data models by modelling the inefficiency term as time-variant. For example, (Farsi et al., 2006) analyse the evolution of efficiency in the Swiss electricity distribution sector in the period 1988-1996 with a true random-effects model and (Cullmann and Von Hirschhausen, 2008b) evaluate the efficiency of Polish electricity distribution companies over the period 1997-2002 both with a fixed-effects and a random-effects models. Nonetheless, in spite of being infrequent, Malmquist indices can also be computed with efficiency estimates from the former parametric frontier methods (Fuentes et al., 2001; Orea, 2002). (Tovar et al., 2011) apply this approach to the Brazilian electricity distribution sector from 1998 to 2005. The main advantage of doing this is once again to decompose the productivity into scale efficiency, pure technical efficiency and the frontier shift.

The last consideration that will be made in this section concerns the robustness of the results obtained. (Bauer et al., 1998) proposed a set of co-called consistency conditions that a robust frontier benchmarking should comply with. These are shown in Table 4-2. The first three consistency conditions are related to the consistency of different frontier methods among themselves, whereas the remaining three conditions refer to the consistency of any individual efficiency estimate with real life.

Mutual-consistency conditions	1. Efficiency scores obtained with different methods should have similar distributional properties (mean, dispersion, etc.)
	2. Different methods should provide a similar ranking of firms
	3. Different methods should identify the same best and worst firms
Consistent-with-reality conditions	4. All approaches should be stable over time
	5. Efficiency scores should be consistent with the actual market conditions
	6. Inefficiencies obtained with frontier methods should be consistent with other methods such as finantial ratios

Table 4-2: Consistency conditions for frontier benchmarking methods (Bauer et al., 1998)

Nevertheless, several studies have shown that different benchmarking models can yield very different results in terms of firms' ranking and overall efficiencies, depending on the selection of the technique or the model variables (Jamasb and Pollitt, 2003; Estache et al., 2004; Farsi et al., 2007). Thus, consistency conditions could be violated when using frontier benchmarking. This becomes particularly relevant when benchmarking is used in regulation since the remuneration of the firms depends on the results obtained. Moreover, translating benchmarking results into X factors and allowed revenues becomes more challenging (Jamasb and Pollitt, 2003; Estache et al., 2004).

In these cases, (Coelli and Perelman, 1999) suggested using the geometric average of different methods for regulatory purposes in order to mitigate the effects of an incorrect model selection. On the other hand, (Estache et al., 2004; Agrell and Bogetoft, 2007) perform several correlation tests between efficiency scores obtained from different methods in order to evaluate the consistency of results. An additional alternative in econometric models, is to measure the significance of the efficiency scores obtained through the ratio of the variance of the inefficiency over the sum of the variances of noise and inefficiencies as done in (Jamasb and Pollitt, 2003). However, the same authors state that several studies have obtained very high values for this ratio, for which a conclusive explanation has not been found.

Consequently, the previous discussion suggests that regulators should carry out benchmarking analysis with different models and specifications. The results should be subject to consistency analyses and serve as a guide to set allowed revenues rather than be taken as an exact science.

4.3.2 Reference benchmarking

The outstanding characteristic of reference benchmarking methods, as compared to black-box benchmarking, lies in the fact that they assume the actual operational environment of the firms or DMUs is known and intend to replicate the behaviour of an efficient firm given the same circumstances. Consequently, an in-depth knowledge of the functioning of the sector is required to develop the models used and perform the benchmarking. Therefore, a higher emphasis will be placed on electricity distribution throughout this section as compared to the previous one.

An additional implication of this approach is that tailor-made solutions, at least for each sector, are required. This leads to a wider range of models which are more difficult to categorise. Broadly speaking, the benchmarks can be constructed either through engineering simulation or optimization models or other non-formalised analyses of the firms' costs and its comparison with other firms operating in similar conditions or resorting to some experts' or consultants' opinion. In all of them, the result is generally a single benchmarking for each company or a group of companies facing similar environments.

The remainder of this section is devoted to the description of different reference benchmarking models specific to the electricity distribution sector. For each of the two groups of reference benchmarking approaches identified, a general description is firstly made. Then, specific examples of their application to regulate electricity distribution companies or proposals for new models found in academic papers will be presented.

4.3.2.1 Reference networks

This benchmarking approach encompasses all methods that rely on the concept of reference or economically adapted network. A reference network is a theoretical quasi-optimal network that complies with the same geographical and technical constraints as real networks at a minimum cost (Cossent et al., 2011b). Thus, a reference network can be used as an objective benchmark for actual grids (Strbac and Allan, 2001). Reference networks are built through engineering models that rely on the characteristics of the actual distribution areas, e.g. location of consumers. The algorithms and methods used are generally different for each of the models developed. Therefore, these will be explained in more detail as the different approaches are presented.

The first reference to adapted networks that can be found in the literature applied to electricity grids can be found in (Rudnick et al., 1996). Nevertheless, the authors propose its application to EHV transmission network pricing with an indicative generation planning as available in the Peruvian and Chilean system in the 1990s. Therefore, this particular application is of little interest in this context. The application of reference networks to distribution networks arouse shortly afterwards. The first publication proposing some kind of reference network model to regulated distribution companies seems to be (Román et al., 1999), which presented a preliminary version of the models that are currently used in Spain to regulate DSOs.

However, the models that can be found in the literature and in actual applications greatly differ among them. These models can be broadly categorised into two main groups, depending on whether they require using detailed geographical information: i) representative networks, and ii) reference network models or norm models.

4.3.2.1.1 Representative networks

A representative network can be defined as a type of reference network which is not built using geographical information, but can be considered appropriate to describe behaviour of a set or cluster of real distribution feeders. The term representative network has been borrowed from (Kawahara et al., 2004). Despite the fact that some authors refer to representative networks as reference networks (see (Strbac and Allan, 2001)), introducing this distinction was deemed necessary to differentiate this approach to that of norm models. A similar distinction can be found in (Lima et al., 2002), who refer to the representative network approach as aggregated approach as opposed to the detail geographic approach, which would correspond to norm models.

Some authors have proposed using representative networks in order to benchmark quality of service, more specifically continuity of supply. The main drivers for the development of these models are basically the limitations of black-box benchmarking methods in taking into account the influence of geography and topography on network investments (Strbac and Allan, 2001; Ajodhia, 2005). Moreover, (Ajodhia, 2005) states that the cost benchmarking RNMs either do not consider quality at all, as in the Swedish model or only in a second stage with some limitations, as the Spanish model. Therefore, specific models are deemed necessary to overcome this limitation.

(Ajodhia, 2005) presented a model named Network Simulation Tool (NST). The NST obtains several reference MV networks with different configurations and protection schemes for a specific distribution area by using a genetic algorithm. The cost of building each one of these reference networks is computed based on some standard costs for conductors, substations, breakers and the remaining network components as well as the cost of losses. Moreover, the reliability of each one of the networks obtained is evaluated by using certain failure rates and repair times in order to compute the frequency and duration of the interruptions experienced by each consumer. This information is then used to calculate the cost associated with the energy not supplied (ENS) suffered by the consumers connected to this network. The value of ENS may be different for different types of consumers, e.g. residential and commercial ones. The NST ends by computing the so-called total social costs (SOTEX) as the sum of the network costs (investments plus losses) and the costs of interruptions.

(Ajodhia et al., 2005) summarises the results obtained with the NST. It is shown that this model allows identifying the characteristics of the grid that minimises the SOTEX for a given distribution area. Moreover, the influence of different parameters such as the cost of network components, failure rates and repair times, the cost of interruptions or load density can be analysed. The main advantage of the NST previously described as compared to other reference network models is that costs and quality are considered simultaneously. However, since only a small section of the MV grid is considered, additional tools are needed for a more comprehensive cost benchmarking. Furthermore, results of the NST are limited by the fact that the location of transformers is not optimised and the NST can only be applied to a specific network configuration.

Along the same lines, (Strbac and Allan, 2001) discusses from a theoretical perspective the use of reference networks to quantify the relationship between the costs incurred by DSOs and the network performance in terms of continuity of supply. The authors proposed to use survey results to quantify the value of quality improvements for consumers. A few years later, the same authors presented a methodology to carry out such as assessment in (Levi et al., 2005).

Substantial differences can be found between Ajodhia's NST and the model proposed by (Levi et al., 2005). The main idea of the latter approach is to obtain a reduced number of networks that can be considered as representative of the actual feeders of the system that we want to analyse. The overall methodology follows several subsequent steps. Firstly, all the feeders under evaluation would be classified into a reduced number of clusters according to certain characteristics such as the type of network, location of switching devices, number of consumers, circuit length, etc. Then, a representative and a reference networks are determined for each one of these clusters. The representative network can be seen as a network that represents the average performance expected from the feeders included in its cluster, whereas the reference network represents the optimum network that can be attained for a specific cluster. Then, the reliability (frequency and duration of interruptions) that can be expected from these two networks is estimated. Finally, the results would be scaled-up to obtain the attainable reliability indices at system level.

This approach presents similar pros and cons to those of Ajodhia's model. Additionally, the results presented in (Levi et al., 2005) do not detail how to construct the reference networks. They only provide a methodology to build representative networks based on some heuristic rules. Using these networks for regulation can be seen as some kind of average performance regulation following the concept of yardstick regulation. On the contrary, using actual reference networks can be seen as related to the concept of efficiency frontiers discussed above. Moreover, the scaling up of the results is not demonstrated in the case study nor clear guidelines are provided.

Building on the previous works, (Kawahara et al., 2004) investigate further about the best criteria to cluster existing feeders into a reduced set of representative networks and how to predict the effect of certain network investments on continuity of supply indices.

The previous uses of representative networks were focused on quality of service and its relationship with some network investments. However, representative networks called primary elementary distribution systems (PEDS) have also been used to regulate overall distribution costs in Brazil (Lima et al., 2002). The method, presented in (Lima et al., 2002), also relies on statistical analyses and clustering algorithms. Real distribution systems are divided into clusters according to certain characteristics such as voltage level of the subtransmission system, number of transformers, number of feeders, number of consumers, peak demand or load factor. Then, a PEDS is constructed for each one of these clusters. Two different types of PEDS were developed, one for densely populated urban areas and another one for scarcely populated rural areas. Finally, the incremental costs that would be incurred to accommodate the load growth expected for each PEDS whilst complying with technical and quality requirements are computed broken down by voltage levels. The averages of these incremental costs for each voltage level are used to set the network charges that distribution companies may collect from their customers.

4.3.2.1.2 Reference network models or norm models

An alternative application of the concept of reference network can be found in some more comprehensive cost benchmarking tools that also rely on geographical information. These tools are generally referred to as RNMs or norm models.

RNMs or norm models resemble the distribution planning models that are used by DSOs to make decisions over their investments. However, the outcome of RNMs does not consist of, or should not be interpreted as, specific network reinforcements or expansions that are required to supply new loads or connect new DG units. What RNMs are intended to is to provide regulators with an estimation of the efficient costs that would be incurred by a distribution company supplying a certain geographical area. Therefore, RNMs tend to be less detailed in the representation of network assets and planning alternatives/candidates than actual distribution planning models. On the other hand, RNMs are capable of covering more extensive geographical areas including different voltage levels within reasonable computation times. Assuming that the RNMs work appropriately, the divergences between the models and real grids can be allocated to inefficient decisions from DSOs or differences in the actual conditions of DG and demand as compared to the assumptions made to run the models. .

Thus, a RNM can be defined as:

"A RNM is a software optimization model able to build a reference network for large distribution areas that connects the supply points with electricity end-consumers, given their geographical location, level of consumption and voltage level, which allow regulators to benchmark the cost efficiency of electricity distribution firms" (Cossent et al., 2011b).

Two distinct types of RNMs can be found. Greenfield models obtain a reference network from scratch, hence disregarding the existing networks. On the other hand, expansion-planning models take the existing grid, or a network created with a greenfield model, as the starting point to compute the reinforcements that are necessary to accommodate the increments in load and new DG connections. The results of greenfield RNMs could be viewed as the efficient level of costs that could be attained in the long-term, whereas expansion-planning RNMs provide mid/short-term levels of efficiency. The different time horizons can have important implications in regulation (Turvey, 2006; Garcia et al., 2008), thus the implementation of the different types of RNMs in regulation should be carefully considered.

RNMs have been applied to regulate electricity distribution companies in several countries, being the most representative ones Spain, Sweden and Chile. The use of norm models has also been reported in some additional countries of South America such as Peru or Brazil (Jamasb and Söderberg, 2010; Silva, 2011), generally as a tool to implement the model company or reference utility regulatory approach that will be described in more detail in section 4.3.2.2. Nonetheless, due to the practical inexistence of available information about the norm models applied in South American countries, the emphasis hereinafter will be placed on the models applied in Spain and Sweden. The following description will cover both the regulatory application made of the models and the technical details about the models themselves. Some additional details about these models can be found in annex B.

i. The Spanish case:

Before presenting the regulatory applications of RNMs in the Spanish system, an overview of the internal functioning of the RNMs used by the Spanish regulator will be provided. This information, including all figures and tables, has been extracted from (Gómez et al., 2012) and (Mateo Domingo et al., 2011). Understanding how RNMs obtain reference networks require bearing in mind the structure of distribution grids described in chapter 1, which comprise several voltage levels (see Figure 4-9).

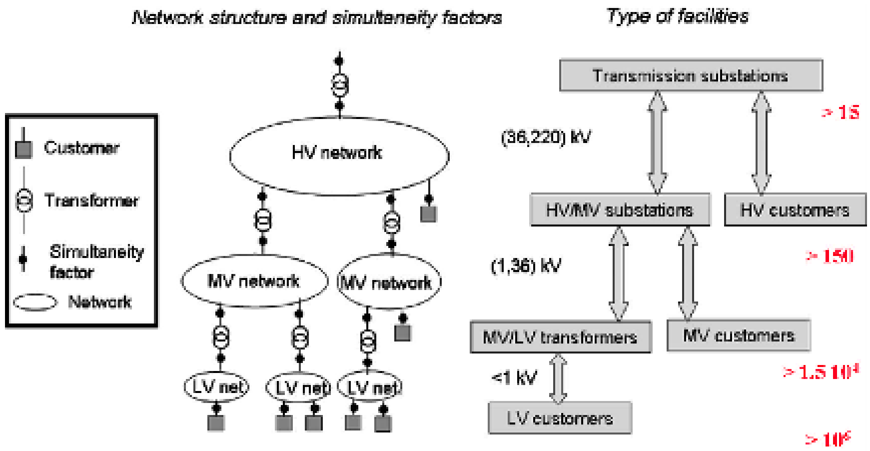

Figure 4-9: Hierarchical structure by voltage levels and size of distribution grids

Simultaneity factors, whose location is shown in Figure 4-9, are needed in order to account for the fact that the maximum power flow in the different network components does not occur at the same moment in time. As the grid voltage level rises, more downstream customers and installations are aggregated. However, the peak of an upstream network element is lower than the sum of the peaks of its downstream fed network components, because in real life they would not take place all at the same time. Therefore a simultaneity factor has to be considered when peak power flows are aggregated. Without simultaneity factors, network components may be assigned a much bigger size than necessary. For example, if DSOs assumed that all LV consumers consume their maximum power at the same time, LV grids and MV/LV transformers would be much bigger in terms of capacity than what it would be actually required.

Similarly, MV/LV transformers and distribution substations have two different simultaneity factors, one upstream of the transformer and another downstream. The upstream simultaneity factor models the fact that not all transformers are at their peak at the same time, whereas the downstream one accounts for the fact that not all the lines connected to them will be loaded at their maximum simultaneously. Simultaneity factors increase with the voltage level due to the fact that the higher the voltage level, the lower the number of network users and installations that are aggregated to compute peak flows.

RNMs sequentially design the different voltage level through the interaction of different heuristics planning algorithms and a geographical information system (GIS). Using the GIS allows taking into account the actual location of network users and network components (in the case of the expansion-planning RNM), as well as other geographical constraints such as environmental factors or street maps within urban areas. Thus, it is possible to consider the cost increase caused by geography and topography, and to optimize the network layout. A sequential planning approach is followed. Firstly, MV/LV transformers are placed, after which the LV network connecting the LV consumers with these transformers is obtained. This process finishes with the design of the HV grid connecting HV consumers and HV/MV substations with transmission substations. Some loops between the designs of different voltage levels are introduced, such as the relocation of substations, in order to minimise overall network costs.

The design of these voltage levels must comply with three main requirements: provide connection to all network users, supply the load without violating any electrical constraint and provide adequate reliability levels. This is achieved by following several steps, shown in Figure 4-10.

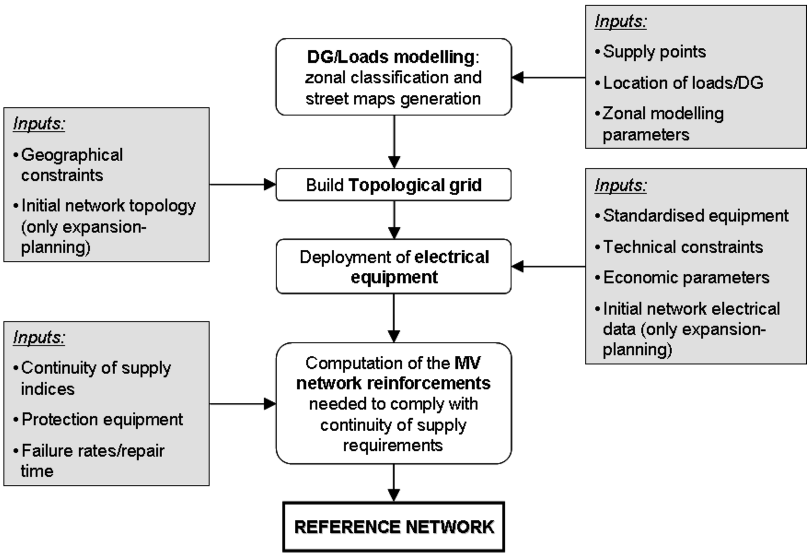

Figure 4-10: Logical architecture of RNMs; steps involved and relevant input data

Firstly, consumption points are sorted into different types of areas (rural, sub-urban, etc.) according to population density and street maps constructed within settlements. Then, the network topology that ensures connectivity and complies with geographical constraints is determined. These geographical constraints depend on whether the lines are within populated areas, where automatically generated street maps guide the network layout, or outside, where exogenous information about orography and forbidden areas (e.g. seas or natural parks) is more relevant[29]. The next stage consists in the deployment of the electrical devices, whose characteristics are drawn from a library of standardized equipment, in such a way that electrical constraints are observed and costs minimized. Lastly, additional feeders and protection devices are installed in the MV grid so as to meet reliability requirements, defined as minimum values of TIEPI and NIEPI for each type of distribution area.

In the end, the objective is to minimize the investment costs plus the present value of energy losses and maintenance costs for a specified number of years. The present value of annual costs is computed through a given WACC, taken as discount factor, considered the same for all costs. It is important to remark that, despite the fact that energy losses are roughly estimated, they must be taken into account in order to adequately dimension grid components since the thermal capacity of a specific conductor may suffice to support a certain power flow; however, the cost of losses may justify a thicker conductor as a more economic solution over its lifetime.

RNMs require extensive input data, which greatly determine the results. Therefore, it is of utmost importance to correctly fine-tune these data. Gathering all this information is one

[29] Further information about how RNMs deal with geographical constraints is provided in annex B.

of the main difficulties of using the RNMs. The most relevant inputs include information about the location and power of consumers and DG units, electrical and economic characteristics of the network components that can be installed and other modelling parameters. Further details about the input data and how these are used in the different modelling stages can be found in annex B.

The results obtained by the RNMs are twofold. On the one hand, a summary of the most relevant information of the network designed (length of lines, transformation capacity, continuity of supply indices achieved, etc.) and the corresponding costs adequately broken down per type of network component. On the other hand, detailed graphical output files are created by the RNMs. Each of these files corresponds to a type of network component which includes not only geographical information of the GIS for the elements of that type, but also electrical information such as impedances, thermal capacity or peak power flow. The expansion-planning RNM provides all the former information differentiating between the initial network and the increments needed to accommodate the increases in network users (both in number and capacity).

Figure 4-11 shows two examples of reference networks, particularly HV and MV levels, obtained from scratch with the greenfield RNM. More information concerning these distribution areas can be found in (Cossent et al., 2011b). Additionally, it can be seen in the image on the right in Figure 4-11 the population settlements that were automatically identified by the model.

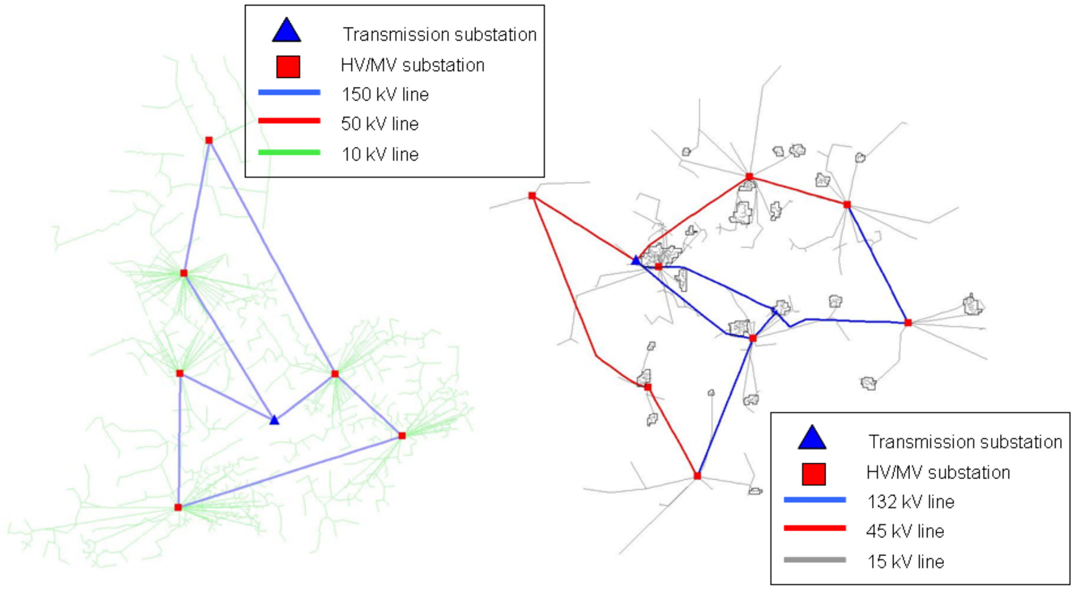

Figure 4-11: Examples of geographical representation of the outputs of RNMs

The Spanish regulation states that a RNM will be used as a tool to perform technical assessments when computing the remuneration of Spanish electricity distribution companies (Ministry of Industry Tourism and Trade, 2008). Both a greenfield and an expansion-planning model are used in the case of Spain. Moreover, the greenfield model applied is capable of performing an intermediate approach consisting of optimizing the grid taking as given not only the location of network users but also the substations. This was mandated by RD 222/2008. Furthermore, the initial network considered by the expansion-planning RNM can be obtained with the green-field RNM, thus allowing to feed one of the models with the results of the other.

Spanish DSOs are remunerated according to the revenue cap formula with four-year regulatory periods. The main difference with respect to a standard revenue cap is that a term that accounts for the variation in costs resulting from the increment in demand in year n-1 is calculated ex-post an added to the allowed revenues in year n[30]. RNMs are applied to compute this ex-post adjustment (Cossent et al., 2011a).

Unfortunately, the regulator does not provide very specific details as to how this is carried out. Notwithstanding, the annual ex-post adjustment was computed, during a transitional period, as the actual growth in demand times a parameter called economies of scale factor (ESF). This parameter represents the increase in distribution costs that are required to supply an additional unit of electricity (4-5). It was computed for each DSO by using the RNMs as explained in (CNE, 2007). The results clearly show that the values of the ESF may be significantly influenced by heterogeneity factors that vary among DSOs such as load concentration or the presence of DG. The ESF values used by the Spanish regulator for the year 2008 ranged between 0.61 and 0.33. From this point onwards, no further information has been made publicly available regarding the application of RNMs, besides the acknowledgement of their being used, to compute the distribution allowed revenues.

$$ESF = \frac{\Delta Cost / Cost}{\Delta Load / Load} \tag{4-5}$$

Additionally, Spanish DSOs perceive incentives to reduce energy losses. The incentive mechanism is designed as a bonus-malus scheme. The reference value in this incentive scheme is calculated through the formula (4-6).

$$E_{ref\,h}^{\;i} = \sum_{cons} \left(E_{cons}^{h} \cdot \left(1 + k_j^h\right) \cdot k_i^h \right) - \sum_{cons} \left(E_{cons}^{h} - E_{trans}^{h} \cdot F_i^h \right) \tag{4-6}$$

Where:

E_{cons}^{h}	Demand in area of DSO i in hour h [kWh]
k_j^h	Loss coefficient of type of client j in hour h
k_i^h	Hourly correction parameter for DSO i
$E_{trans}{}^{h}$	Transmission losses in hour h [kWh]
$F^h{}_j$	Share of load in the area of DSO i in hour h over total system consumption

The full details of this formula can be found in (Cossent et al., 2011a). The main outstanding feature that is important in this context is that the reference values depend of a zonal loss coefficient, computed separately for each DSO and each period of time, and that this zonal loss coefficient is computed with the RNMs. These DSO-specific factors should be computed for every hour, or at least for peak and valley hours. At the moment, they are computed only for peak and valley hours. The methodology followed and the results obtained using data from the years 2007 and 2008 can be found in (CNE, 2010). A similar methodology was applied in (González-Sotres et al., 2011) to estimate the effect of the presence of DG on distribution losses. Similarly to the previous case, results denote the significant influence of variables exogenous to DSOs related to the geographical characteristics of their distribution areas and the connection of DG.

[30] The Spanish regulatory framework will be described in more detail in chapter 5.

The first regulatory period when RNMs have been applied in Spain comprises the period 2009-2012. Therefore, in–depth assessments of the effectiveness of RNMs in the Spanish case are not yet available. Nonetheless, some preliminary conclusions can be drawn. Firstly, it is noteworthy most complaints from DSOs can be associated with the regulatory design, which includes an ex-post revision, and the lack of transparency from the regulator. The regulator is currently committed to the use of the model. Hence, it is expected that in the coming years more experience will be gained, both by the regulator and DSOs, and well-defined methodologies will be developed.

ii. The Swedish case:

A new approach to the regulation of DSOs was introduced in the year 2004. This new regulatory model was called the Network Performance Assessment Model (NPAM). Unless said otherwise, the description of the NPAM shown below as well as all the figures has been taken from (Larsson, 2005) and (Larsson, 2003). The Swedish approach is based on the quantification of the different so-called customer values, i.e. the services consumers expect from network companies and for which they are willing to pay. Four customer values were identified: connection (access to electricity), reliability (continuity of supply), delivery (energy losses) and grid administration (metering and billing).

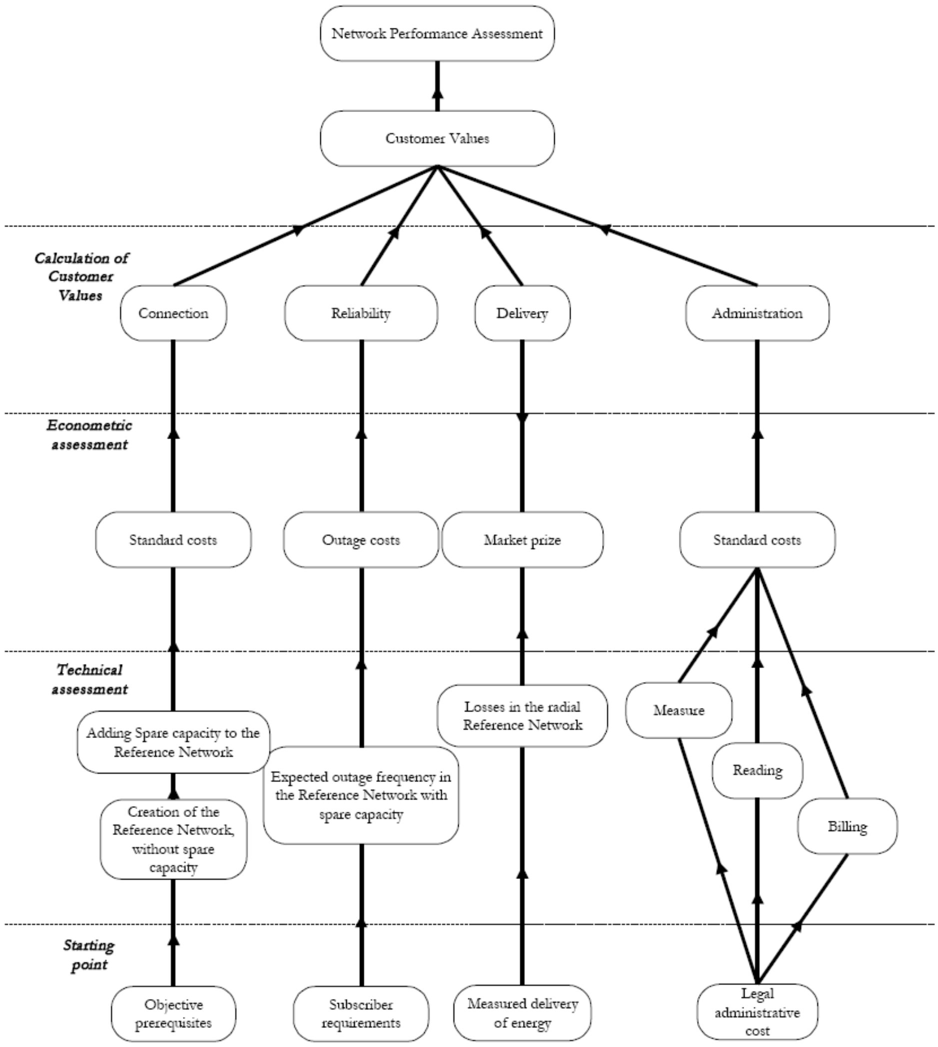

Figure 4-12: Steps to quantify the NPAM customer values

The former customer values are computed separately through a bottom-up process shown in

Figure 4-12. It can be seen that reference networks are used to compute the first three customer values. However, the grid administration value is computed by assuming certain standard metering and billing costs for each consumer. Therefore, the description provided below will focus on the connection, reliability and delivery customer values.

Connection: the value of grid connection is calculated by designing a reference network for each DSO valuing the assets according to some standard costs. Contrary to the Spanish RNMs, only greenfield reference networks can be designed. Initially, a radial network that connects end consumers with the points of supply or boundary points according to some predefined heuristic rules (no optimization is performed). The different voltage levels are taken into account in order to decide where to connect consumers, what aggregation rules (simultaneity factors) to apply or the costs of network components. At this point, the costs of network components and energy losses have not been considered yet. Thus, the topology of the reference network and the sizing of transformers and lines have been made solely on the basis of the location of consumers, their consumption profile, technical constraints and the heuristic planning rules. An example of the radial networks obtained is depicted in

Figure 4-13.

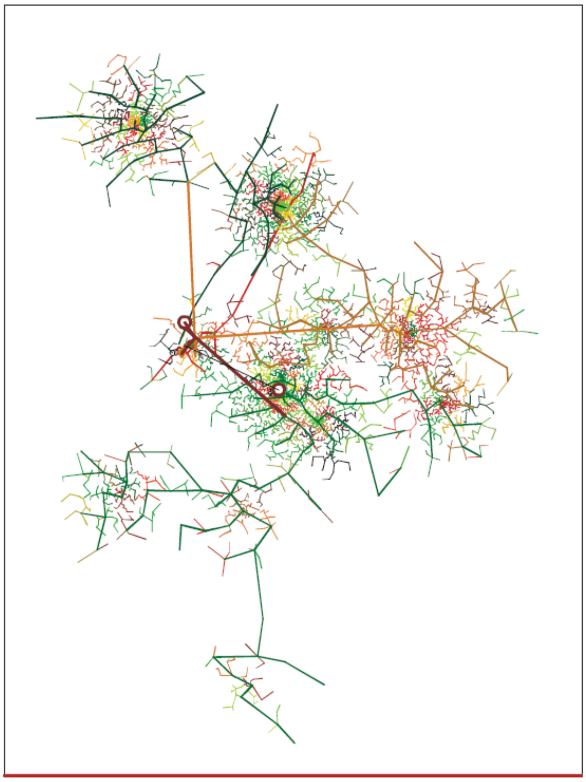

Figure 4-13: Example of a reference network obtained with the NPAM

The next step is to calculate the cost of this reference network. The annual investment costs for each line and transformer is calculated according to an empirical cost function that represents the cost of each element as dependant on the density of consumers, for example as length of the line per consumer. The functional relationship finally chosen was a modified hyperbolic tangent as the one in (4-7), where x is the consumer density variable and k_0 to k_4 are empirical parameters. Finally a standard cost is added to the investment costs to account for asset operation and maintenance.

$$Mod\tanh(x) = \left(k_1 + k_2 \cdot \tanh\left(k_{3.} \cdot \tanh(x - k_4)\right)\right)^{k_0} \quad \textbf{(4-7)}$$

Reliability: the customer value related to reliability is quantified as the amount of extra spare capacity that needs to be added to the radial reference grid so that the cost of interruptions for consumers does not surpass the reinforcements needed to increase the grid reliability. Then, the expected reliability obtained with this final network, which includes spare capacity, is compared to the actual reliability achieved by DSOs. Those DSOs who provide poorer reliability than the one obtained by the NPAM will see their network performance assessment (NPA) reduced accordingly. The expected reliability of the reference network with spare capacity is calculated through Monte Carlo simulations and the cost of interruptions for consumers is estimated on the basis of a survey carried out among Swedish consumers. Annex B presents further information about the computation of the reliability customer value.

Delivery: this customer value accounts for energy losses produced in distribution networks. (Larsson, 2005) states that, on a temporary basis, losses were estimated from a template curve according to which energy losses depend on the density of consumers. Nonetheless, a complete physical calculation, presumably involving running a power flow on the radial reference network, would be implemented later. However, subsequent evaluations of the model still rely on the template curve (Jamasb and Pollitt, 2008; Wallnerstrom and Bertling, 2008). Hence, it seems that this modification was never implemented. Once the energy losses are estimated, these are valued according to the electricity market prices.

The previous description already mentioned some of the input data necessary to run the NPAM. These include the information related to the geographical coordinates of network users and points of connection with other grids. Additionally, the information about past interruptions concerning their occurrence and duration must be provided by DSOs. Moreover, the NPAM requires data on standard lines and transformers in terms of electrical constraints and an investment cost function. The remaining information corresponds to modelling parameters inputted by the model user such as depreciation times, interest rates, etc. Further details can be found in annex B.

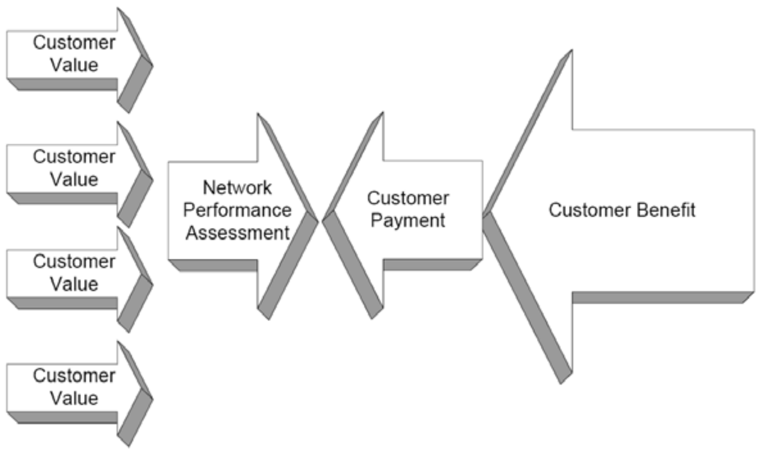

Figure 4-14: NPAM versus consumer payment

Now that the norm model used in Sweden has been described, the regulatory use of this model and the experiences gathered in Sweden will be presented. It should be mentioned that prior to the implementation of incentive regulation, the Swedish regulation followed a light-handed approach. Therefore, one of the goals to be achieved when implementing the use of the NPAM presumably was to minimise the extent of the regulatory intervention. This led to the implementation of ex-post annual reviews when the NPA computed by the regulator was compared to the actual payments made by consumers (

Figure 4-14).

The ratio of a DSO revenues and its NPA is called the debiting rate. DSOs whose debiting rate deviated from unity more than a certain threshold were suspected to be inefficient, thus triggering further regulatory scrutiny. If the DSO failed to adequately justify this deviation, the regulator could impose compensations to the DSO's consumers or stricter cost-saving targets (Jamasb and Söderberg, 2010).

The Swedish experienced was discontinued a few years after its implementation. The main reason is the fact that frequent litigations between DSOs and the regulator took place. This even lead to court decisions that ruled against the model. Despite this unfortunate experience, several lessons can be extracted from this. Two types of criticisms to the NPAM can be found.

On the one hand, the engineering model itself presented several shortcoming related to the assumptions and simplifications made. (Wallnerstrom and Bertling, 2008) investigated the robustness of the NPAM to slight variations in some of the inputs. It was shown that small changes in the location and consumption of customers could produce significant variations in the results of the model[31]. Furthermore, the results presented show that the cost variations are not consistent since different types of distribution areas are differently affected and the NPA may either increase or decrease for similar changes. The authors suggest that this can be caused by some planning rules embedded in the NPAM. More specifically, they mention the fact that transformers are placed at the same coordinates as an existing consumer, therefore changes in the location of consumers can lead to big variations in the grid topology, and the fact that variations in the location of the points that connect to upstream networks could significantly increase the length of HV lines.

On the other hand, the regulatory design of the NPAM implementation was severely flawed. The frequent (annual) reviews that showed a very short-term perspective together with the ex-post and backward-looking approach created high regulatory uncertainty for DSOs. This created very poor incentives for investments, innovation and long-term efficiency (Jamasb and Pollitt, 2008). Moreover, (Jamasb and Pollitt, 2008) also report some further undesired characteristics of the former Swedish regulation such as the high risk of regulatory capture and litigation due to the excessive focus on the regulatory versus utility relationship, the lack of transparency, a large dependence of the model on customer density, and the inability of the model to reflect the dynamic behaviour of firms. Furthermore, (Jamasb and Söderberg, 2010) report that even though the NPAM had indeed driven the costs of the more inefficient firms down, the more efficient firms had behaved opportunistically by raising their prices knowing that, as long as they remain under the threshold debiting rate, they would not be subject to regulatory scrutiny.

Overall, it seems that, despite the limitations of the model itself, the main reasons behind the court appeals that would subsequently lead to discarding the use of NPAM were related to the regulatory design.

[31] The customer value related to administration and services was not affected since this was computed on the basis of standard costs independently from the reference network.

iii. Use of RNMs in Chile

Chilean distribution firms have been traditionally regulated under the so-called model company approach. This consisted in building a bottom-up efficient firm for each company. Despite the fact that the models company regulation will be described in section 4.3.2.2, investment cost were calculated as the new replacement value (NRV) of an adapted network (Rudnick and Donoso, 2000). The regulation, summarised in (CNE, 2006), does not specifies the methodology to compute this NRV. Therefore, the consultants hired by the regulator and the companies themselves, who must also provide their own estimates, could in principle use any methodology that complies with the general guidelines set by the Chilean regulator.

Nonetheless, (Rudnick and Donoso, 2000) proposed to implement the use of RNMs such as the one presented in (Román et al., 1999) to minimise the cost of assets. In fact, a more recent paper presented results for a RNM that resembles the Spanish one (Navarro and Rudnick, 2009a; Navarro and Rudnick, 2009b). What is more, the studies performed by independent consultant and distribution companies for the regulatory period 2008-2012, which can be consulted at the CNE's webpage (CNE, 2011), show that all consultants and Chilectra (biggest distribution company in Chile) used the PECO model. The PECO model is a greenfield RNM which is the predecessor of the RNMs that are currently being used in Spain (Mateo Domingo et al., 2011). More details about the PECO model can be found in (Román et al., 1999; Peco, 2001; Peco, 2004). Hence, it can be concluded that RNMs have been widely applied to regulate Chilean distribution companies as part of a broader regulatory process.

iv. Some additional considerations about the use of RNMs

Most references describing the use of RNMs, pay little attention to the determination of the costs of network components given as inputs to the RNMs. However, these input data can potentially significantly influence the results obtained by the model and their incentive properties, especially in those RNMs that perform a cost minimisation such as the Spanish RNMs. The costs included in the catalogue are generally provided by the companies. However, DSOs may try to tamper with the data to game the regulator. Therefore, regulators tend to use standardised and audited costs. In the future, it should be studied whether these costs can be subject to some kind of benchmarking across firms. If average values are used, the approach would be closer to yardstick competition, whereas if the most efficient values are used, it would mimic frontier benchmarking. Benchmarking unit costs has already been done by OFGEM in the latest DPCR as explained in (OFGEM, 2009c).

One of the main criticisms to the use of RNMs is that they remove the elements that induce competition among firms present in black-box benchmarking approaches. Notwithstanding, some of these elements could be introduced into the application of RNMs. Besides the aforementioned use of standard or benchmarked costs as inputs, the concept of relative reference networks was proposed by (Paulun et al., 2008). This approach, illustrated in Figure 4-15 and Table 4-3, consists of comparing the actual costs of existing networks and those obtained with a RNM. The efficiency of the network firm closer to the results of the RNM would be assigned 100% efficiency, whereas the efficiency rates of remaining utilities would be reduced proportionally.

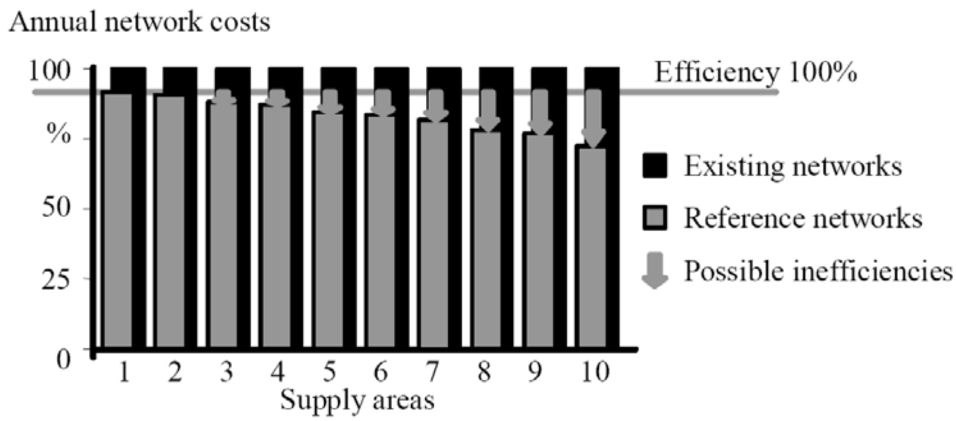

Figure 4-15: Computing efficiency with relative reference networks. Source: (Paulun et al., 2008)

Firm	Actual cost	Reference cost	Overall efficiency	Relative efficiency
A	115	100	86.96%	90.11%
B	78	70	89.74%	92.90%
C	95	92	96.84%	100.00%
D	65	57	87.69%	90.85%
E	25	22	88.00%	91.16%

Table 4-3: Illustration of the efficiency computation of distribution firms under the relative reference network approach.

Another important limitation of RNMs is that they only allow regulators to analyse the situation of DSOs at a specific point in time. However, actual networks are designed and built in a dynamic process full of uncertainties. In order to address this limitation, a model to evaluate the system adaptation over time of electricity distribution networks was proposed in (Garcia et al., 2008; Schweickardt and Miranda, 2009). This is a two-stage model that combines a long-term planning perspective to minimise the cost of the network and a medium to short term planning that handles the adaptation of this network to the mid/short term deviations from the initial situation.

The long-term network planning is not addressed in detail in the previous papers as it is assumed that the results of a long-term planning process are available. Nonetheless, these authors propose to solve the first stage through a distribution planning model that minimises the cost of the network and the non-served energy (NSE), subject to capacity, voltage and radiality constraints. According to this description, the authors seem to be proposing something very similar to a greenfield RNM.

For the second stage, which constitutes the core of their contribution, they propose to use fuzzy dynamic programming and analytical hierarchy processes to assess the adaptation of the distribution grid over time. Fuzzy sets are used to quantify the adaptation of the network, measured through several parameters or criteria such as the costs, interruption indices, energy losses, or the environmental impact of the construction of network assets. These fuzzy sets are then used as inputs to the analytical hierarchy process that results in the computation of a dynamic adaptation vector.

4.3.2.2 Other reference benchmarking methods

This category comprises a wide range of loosely defined benchmarking approaches that have in common the fact that an in-depth knowledge of the inner functioning of the regulated firms is required. These methods are generally carried out combining both external consultancy and in-house analyses on the basis of the information collected from the utilities together with expert knowledge and comparisons of different ratios among regulated firms. These processes sometimes include the use of some of the previously explained benchmarking methods. In some cases, international or intra-sector comparisons are also performed. A few representative examples of other reference benchmarking methods will be briefly described.

In South American countries, the concept of model company[32] has been extensively used to determine the allowed revenues, or allowed prices, of distribution companies (Rudnick and Zolezzi, 2001; Lima et al., 2002). Among these countries, we may find Argentina, Chile, Peru or Brazil. This consists of "building" bottom-up a company comparable to the actual one or a set of actual firms. The model company is characterised in terms of network assets and associated costs, overhead structure (corporate and administrative services) and commercial costs (billing, metering, etc). Nevertheless, the concept of model company is rather generic. In fact several different, yet complementary, methodologies can be applied to determine this model firm. The papers proposing and/or describing the use of model companies to regulate distribution companies refer to regression studies, black-box benchmarking, reference networks or external consultancy.

In the UK, OFGEM introduced a sliding scale mechanism in DPCR4 to encourage DSOs to provide accurate forecasts for CAPEX (Crouch, 2006). This mechanism was extended to OPEX during the last price control (OFGEM, 2009b). Nonetheless, it is necessary to set a baseline of costs for each DSO which will be compared with the DSOs' forecasts in order to determine the final allowed revenues and the power of the incentive mechanism. In DPCR 4, OFGEM hired the consultancy firm PB Power to produce these baselines, whereas OFGEM performed detailed in-house analyses during DPCR5. The methodology followed in this last price control to determine the baseline associated with network costs will be presented. The information has been obtained from (OFGEM, 2009a; OFGEM, 2009c).

In order to benchmark OPEX, parametric benchmarking with panel data seems to be the main tool. Moreover, some international benchmarking using data from US distribution companies has been performed. The costs that could not be subject to benchmarking are assessed by independent consultants. DEA is also used to cross-check the results. Since all these methods have been previously explained, no further details will be provided.

The methodology followed to determine the baseline for network investments is depicted in Figure 4-16. The analytical model box comprises all the methods that have been used to evaluate the different cost components. These methods include an age based asset replacement model, unit cost benchmarking, a reinforcement model, trend analysis, etc. The network reinforcement model and the asset replacement models are the central tools in these analyses, as they are used to determine almost 80% of network investments. These models can be considered as reference benchmarking tools as they require in-depth analysis of the inner functioning of the regulated firms.

32 The terms model company, model firm or model utility will be used indistinctively since they are used in the literature with practically the same meaning.

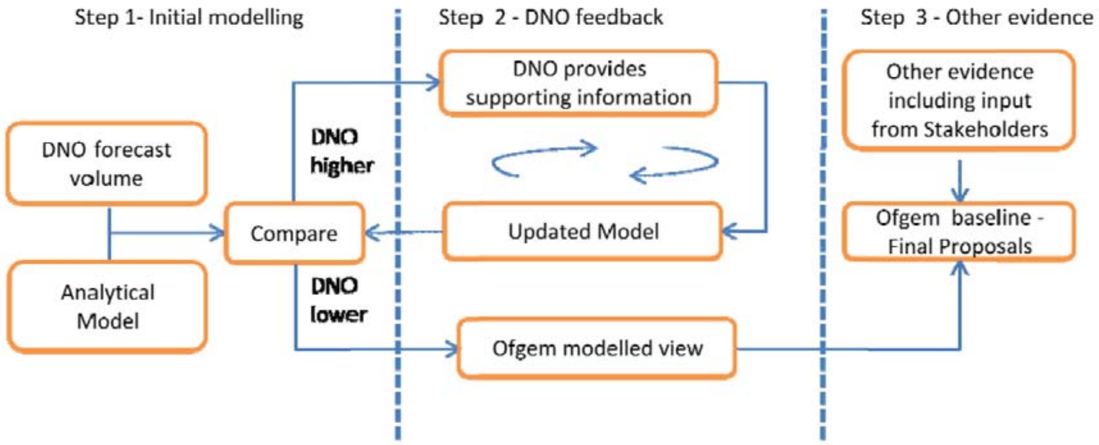

Figure 4-16: Network investments assessment methodology in UK's DPCR5. (OFGEM, 2009c)

The general reinforcement model is based on benchmarking the ratio of capacity added in EHV and 132 kV assets over the growth in peak demand across DSOs. Moreover, the unit costs are also benchmarked to the industry average. This is basically an average benchmarking of some ratios, as shown in Figure 4-17. OFGEM deemed it necessary to perform several discretionary adjustments such as removing one DNO (EDFE LPN) due to the particular characteristics of the area it supplies or excluding investments driven by the N-2 security criterion. DSOs were requested to provide information about the large variations across DSOs that were observed. Some issues pointed out by OFGEM driving the results are the lumpiness of investments or the differences in the expected future load growth.

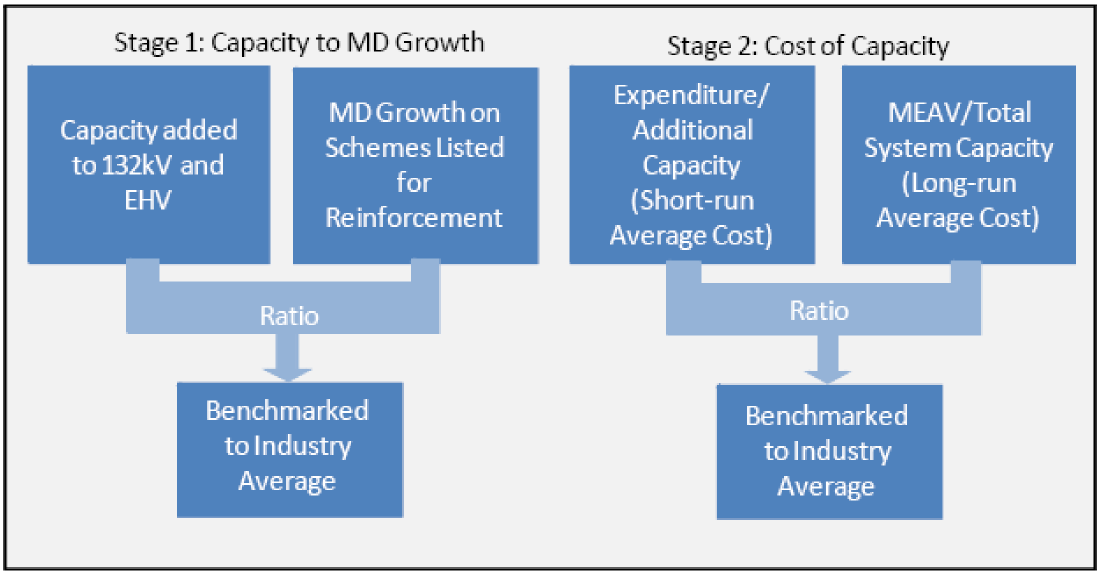

Figure 4-17: Reinforcement model used in DPCR5 (MD stands for Maximum Demand and MEAV for Modern Equivalent Asset Value) (OFGEM, 2009c)

The investment required to reinforce the lower voltage levels of the distribution network were determined on the basis of the investments made during the previous regulatory period and the overall economic conditions. Since significant load growths were not expected in the MV and LV levels, investment allowances were set at similar levels as in the previous price control.

The asset replacement model is used to quantify the need of a DSO to invest in order to replace aged assets before their failure. This is an age based asset survivor model that OFGEM has used in previous DPCRs and similar models have been used by DNOs themselves (OFGEM, 2009c). The model applies a probability distribution function that represents the probability of an asset to require being replaced as a function of its age. This distribution function (Poisson distribution function) is built based on historical data and forecasts, benchmarked across DSOs (see Figure 4-18). DSOs may submit additional information to justify deviations from the survivor model. The results were disaggregated by voltage levels and type of assets. It is noteworthy that some DSOs reported significantly higher replacement costs than expected by the model and vice versa.

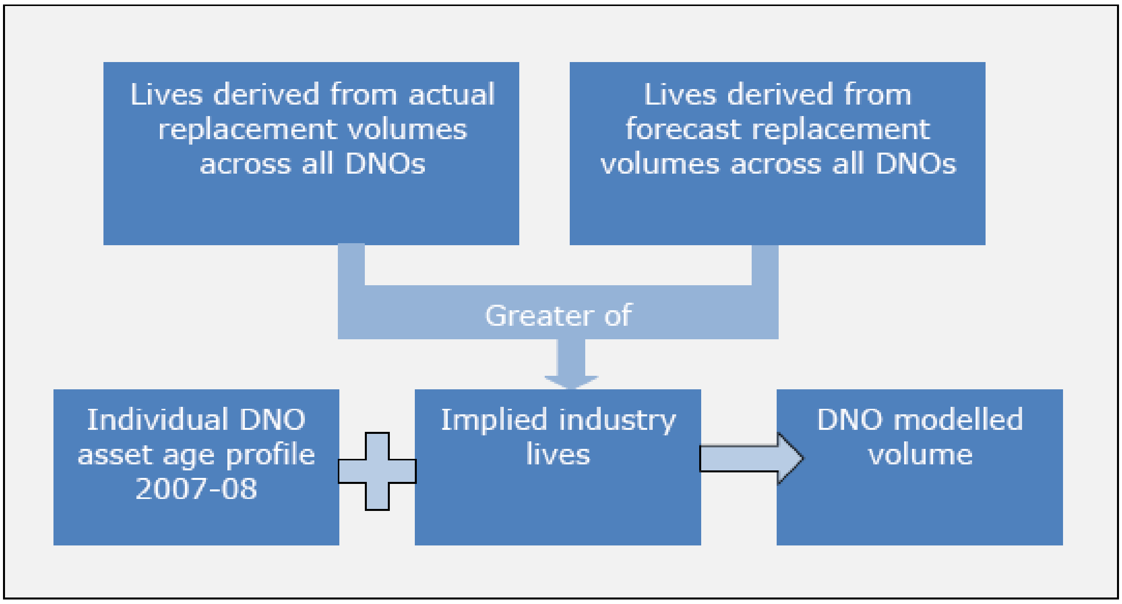

Figure 4-18: Asset replacement model in DPCR5 (OFGEM, 2009c)

The last reference benchmarking method that will be presented is the optimised deprival value (ODV) implemented in New Zealand to valuate fixed assets of distribution companies. The ODV is defined as the value of network assets *"at the level at which they can be commercially sustained in the long term, and no more. The resulting value should be equal to the loss to the owner if they were deprived of the assets and then took action to minimise their loss"* (New Zealand Commerce Commission, 2002). According to (Turvey, 2006), this approach is rather similar to the Australian depreciated optimised replacement cost (ODRC) described in (Johnstone, 2003). These methods are generically referred to as "scorched node approaches" (Turvey, 2006). The overall ODV methodology is defined in (Ministry of Economic Development, 2000), although further details about its implementation can be found in (New Zealand Commerce Commission, 2002).

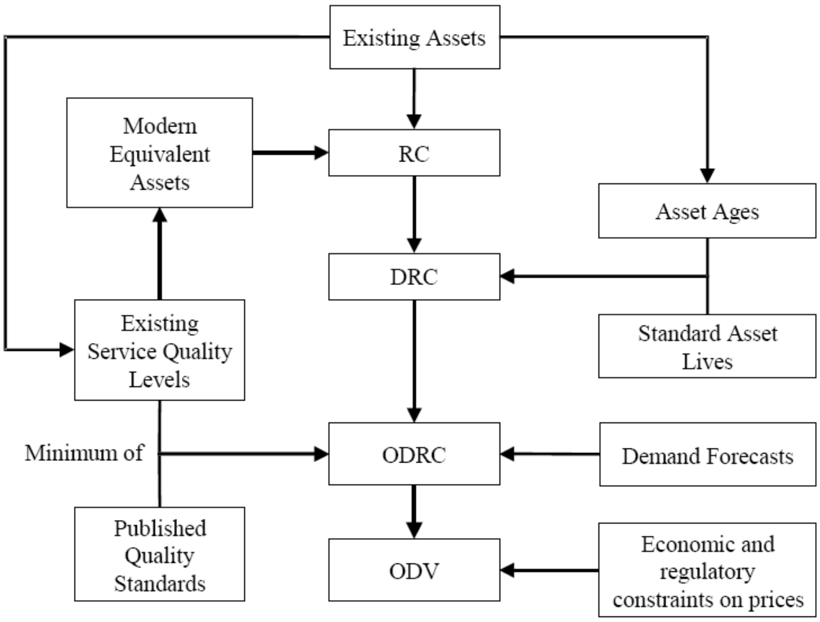

Figure 4-19: Prescribed ODV methodology (New Zealand Commerce Commission, 2002)

The ODV is obtained as the minimum of the economic value of the assets and its ODRC (Ministry of Economic Development, 2000; Turvey, 2006). The economic value of assets is the maximum of their present value (value for users) and their net realisable value (disposal value). However, in practice, the ODV is determined as the ODRC in most cases (Gunn and Sharp, 1999; New Zealand Commerce Commission, 2002). The overall methodology for the computation of the ODV is depicted in Figure 4-19. Firstly the replacement cost of existing assets is computed valued at the standardised cost of modern equivalent assets. Based on the age of existing assets and some standard asset lives, the depreciated value of the replacement costs is calculated. Then, an optimization is carried out by removing surplus assets that are not essential to meet the expected demand whilst complying with quality of service requirements. This step is intended to disallow inefficient investments and promote efficiency in future investments. Finally, the ODV is computed on the basis of previously calculated ODRC and potential constraints on electricity prices paid by end consumers.

4.4 Summary and conclusions

Regulatory benchmarking has gained an increasing importance due to the extensive implementation of incentive regulation. This has implied the development of numerous methodologies to assess the behaviour of DSOs and other regulated firms. This chapter has presented a thorough review of existing classification of benchmarking approaches, which showed that a commonly agreed taxonomy of the different benchmarking methods does not exist. Several inconsistencies among the different classifications were found. Additionally, they generally showed several gaps, mostly in the categorization of methods that rely on the knowledge of the inner DSO operations, i.e. reference methods. This is presumably due to the fact that, contrary to frontier methods, these models are quite specific to each application. Therefore, there was a clear need for a more comprehensive categorization of benchmarking approaches.

A new comprehensive taxonomy has been proposed in this chapter. Previous taxonomies classified benchmarking methods according to what is benchmarked (productivity vs.

efficiency, total vs. partial, etc.). On the other hand, in the proposed classification, benchmarking approaches are sorted out according to the intrinsic characteristics of the methods themselves. The principal criterion depends on whether the inner activities of the regulated sector are assumed to be known or not. Thus, greater generality is attained. As a results, two main groups have been identified, namely black-box benchmarking and reference benchmarking. Frontier benchmarking methods stand out within the former group, whereas norm models represent the main reference benchmarking method.

The detailed review of the different methods and their application to analyze electricity DSOs has revealed very different evolutions for both types of methods. Black-box methods, particularly frontier models, generally start from theoretical developments which may end up being applied in practice. In fact, many of the methods described in this chapter have not been applied to the electricity distribution sector. On the contrary, reference methods seem to originate from the need of regulators to somehow evaluate the investment needs of DSOs, for which they do not find theoretical developments available. This is evidenced by the fact that, in spite of the generalized application of reference benchmarking suggested by existing surveys, even if informal; little information can be found in the literature.

Furthermore, the review of methods and practical experiences described has shown that benchmarking models cannot be directly implemented in revenue determination. In the end, some discretionary decisions from the regulator are required on the basis of benchmarking results. Lastly, how to apply benchmarking can be as important as the selection of the benchmarking model. For example, it has been seen that the use of norm models in Spain and Sweden has been criticized mainly due to the regulatory implementation rather than for the models used themselves.

Main conclusions:

- Benchmarking is a central regulatory tool for incentive regulation schemes. However, a commonly agreed classification of approaches does not exist
- A new comprehensive taxonomy of benchmarking methods has been proposed, identifying two main approaches: black-box and reference benchmarking
- Black-box methods started from theoretical works and were later applied in practice, whereas reference methods were driven by the need of regulators to evaluate efficient network investments
- Benchmarking can guide regulators. Nonetheless, some discretionary decisions will always be necessary
- How benchmarking is applied can be as important as the selection of benchmarking model itself

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5. Setting the allowed revenues of DSOs

Determining the allowed revenues of each DSO constitutes one of the main tasks of regulators concerning electricity distribution. The major goal is to encourage DSOs to increase efficiency and reduce costs while, at the same time, the financial viability of the firms is ensured. Nonetheless, the asymmetries of information between regulators may lead to opportunistic behaviour and hamper the tasks of regulators. Chapters 3 and 4 already described in detail the many tools and incentive mechanisms that can be used to mitigate the effects of information asymmetries. This chapter will go further by focusing on how these should be applied and integrated into an overall remuneration formula so as to better attain the aforementioned target.

The main difficulty in the regulation of natural monopolies is posed by the existence of large amounts of long-lived sunk investments. For instance, it is difficult to assess whether installing a transformer today should be considered as efficient when it is going to be in operation for the next 40 years. This is even more difficult due the fact that different firms, or the same firm at a different point in time, have to face different conditions such as geography, opposition to the installation of new lines, cost of capital, cost of labour, demand growth or the historical evolution of their grids. Conventionally, the effects of these difficulties were mitigated by the fact that electricity distribution was characterized by a developed and stable technology and the well-known and predictable behaviour of demand. However, smart grid technologies and DER penetration deeply alters this paradigm, thus requiring a critical review of conventional DSO remuneration practices.

Hereinafter, some alternatives for the remuneration of DSOs that facilitate the transition to smarter distribution grids and the connection of DER will be proposed. The chapter starts by presenting a brief discussion about the overall remuneration formula and the design of price review processes in section 5.1. Section 5.2 introduces the major challenges for the regulation of DSO revenues in the new context and presents the regulatory framework proposed in the thesis to address the previous problems. The proposed approach will be illustrated in section 5.3 by a detailed analysis of the amendments that would be required in current Spanish regulation for their implementation. The chapter finishes with some conclusions in section 5.4.

5.1 Remuneration formula and design of price reviews

Broadly speaking, regulators may opt to set either the prices charged by DSOs or the revenues they obtain. As described in chapter 2, revenue regulation is more suitable for electricity distribution under the presence of large amounts of DER since they can cause variations in the amount of energy distributed that are not properly coupled with distribution network costs. This is in agreement with the theoretical findings about the shortcomings of price-only regulation when demand and costs are uncertain (Blair et al., 1995). Hence, subsequent discussions will focus exclusively on revenue regulation. Moreover, following theoretical developments and the practical experience gathered over the last decades, some form of incentive regulation that decouples revenues from actual costs is deemed necessary to balance the tradeoffs between adverse selection and moral hazard problems faced by regulators. This leads to the selection of a revenue cap remuneration formula.

Notwithstanding, many different implementations of a revenue cap formula can be found. Generally, these are based on the conventional RPI-X formulation. However, significant variations can be found in its implementation. Alternative revenue cap formulas may include the addition of revenue drivers, Z factors to account for unexpected events causing cost deviations, an extra term representing non-controllable costs exempted from efficiency gain requirements or the use of different price indices (retail prices, industrial prices, etc.). Nonetheless, the major differences are related to the determination of the allowed revenues in the first year of the regulatory period and the X factor.

This can be done either by setting the initial allowed revenues according to past costs and the X factor to induce a future efficient performance or by modifying both parameters at the beginning of each regulatory period. Additionally, the X factor could be the same for all DSOs or a different one for each firm. In any case, these two parameters are generally set jointly by using some form of regulatory benchmarking (see Chapter 4). Depending on when regulators perform these efficiency assessments, one may distinguish between ex-ante and ex-post regulation. Essentially, ex-post regulation is simpler to implement for regulators. Notwithstanding, this creates important regulatory uncertainties which may prevent DSOs from investing (regulatory clawback). On the other hand, a purely ex-ante approach may cause large deviations between actual costs and DSO revenues that can harm DSOs or end-consumers. This is the reason why, in practice, any regulatory framework lies in between these two extremes.

The length of regulatory periods in revenue/price cap regulation, usually set between 3 to 5 years, is another relevant parameter. Short periods dilute the incentives to increase efficiency through actions that yield benefits in the long-term (asset replacement, staff training, R&D expenditure) and increase the regulatory burden both on regulators and DSOs. On the other hand, frequent price reviews reduce the uncertainties faced by regulators and prevent large deviations between DSO costs and revenues. In order to overcome these difficulties, OFGEM has recently proposed to increase the length of regulatory periods in the UK from 5 to 8 years, although they admit that implementing this guideline may require introducing additional mechanisms to control for uncertainties or reviewing this length in the future (OFGEM, 2010a).

Summing up, every regulatory design should start by defining the type of remuneration formula and its terms. Moreover, it is to be determined how often a price review process is opened and how the efficient costs for each firm are determined during these price reviews: regulatory benchmarking models, ex-ante or ex-post approach, how to equalize incentives for short and long term efficiency gains, etc. Most of these questions will be addressed in subsequent sections.

5.2 Proposals for regulating distribution expenditures under the new context

The regulatory challenges caused by the connection of DER and the transition towards smarter distribution grids were reviewed in detail in chapter 2. Essentially, regulation should provide a stable and clear framework that provides DSOs with incentives to invest in order to increase network capacity and replace aged assets to accommodate growing levels of DER, as well as develop innovative infrastructures aimed at attaining the participation of network users (ERGEG, 2010; Benedettini and Pontoni, 2012).

This must be done in a context characterized by high demand uncertainty and obsolescence risks driven by the importance of new distribution network users such as

DG or EVs and the new needs of end-consumers together with rapid technological changes. Additionally, the current financial situation may also restrict the access to funding in many countries. This strengthens the need for a clear and predictable remuneration. Since this is considered the main challenge for the economic regulation of DSOs in the coming years, the focus hereinafter will be placed on the determination of new investment requirements and their inclusion in the RAB and DSO remuneration.

Under the aforementioned conditions, intrusive ex-post adjustments to the remuneration should be avoided to prevent creating regulatory uncertainty that would potentially discourage DSOs from investing. Hence, it is advisable to follow the principle that the regulator should remunerate according to the costs that could be considered to be efficiently incurred with the information available at the time when they were incurred (Alexander and Harris, 2005). However, purely ex-ante approaches could create perverse incentives for gaming, mainly through overestimating the investments required or by deferring planned investments (Alexander and Harris, 2005). Trigger mechanisms or reopeners can be used to correct for deviations between ex-ante projections and actual investments. However, these are better suited for very specific and major investments as in UK airport regulation (Alexander and Harris, 2005) or for exceptional unpredicted situations as implemented in UK electricity distribution regulation (OFGEM, 2009a).

Therefore, regulatory schemes based on an ex-ante computation of revenue allowances with an ex-post correction can be particularly suitable, especially concerning CAPEX allowances (Cossent et al., 2009). A profit-sharing approach, based on an ex-ante revenue allowance determination with an ex-post review based on ex-ante rules over the overall DSO revenues, is proposed herein. The major goal is to balance the trade-off between the incentives to gain in efficiency and avoid excessively large deviations between costs and revenues, whilst mitigating regulatory uncertainty.

On the other hand, (Laffont and Tirole, 1993) found that offering regulated firms with a menu of regulatory contracts with different profit-sharing provisions could yield better results than a single profit-sharing contract. As discussed in (Joskow, 2005), such a menu would comprise a set of contracts with different power of the incentives to cut costs. Some of the contracts would be closer to a price or revenue cap regulation, whereas others would be closer to a cost of service regulatory contract. Thus, the menu of contracts would encourage regulated firms to reveal their true cost reduction opportunities. For these reasons, as shown in Figure 5-1, menu regulation can be considered as an evolution of incentive regulation (Tahvanainen et al., 2012).

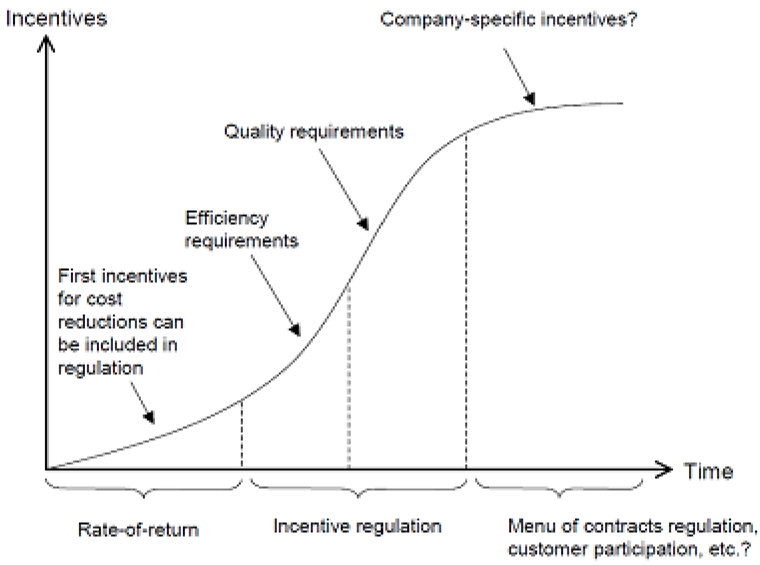

Figure 5-1: Evolution of regulatory models (Viljainen, 2005)

However, there is scarce experience in the use of menu regulation for electricity distribution. (Agrell and Bogetoft, 2003) examine the role of menus of contracts in electricity distribution regulation and discuss its potential application to the Norwegian context. Firstly, the authors compare two contracts consisting in an ex-ante revenue cap and an ex-post yardstick revenue determination. This menu would reveal the true opportunities face by different firms to reduce costs. Secondly, the authors compare another set of contracts which defer in the length of the period between cost reviews. According to the authors, this menu would reveal the age of the assets, thus mitigating the problems associated with the evaluation of the regulatory asset base, e.g. whether to use book values or replacement costs.

Notwithstanding, the only actual application of menu regulation that has been found is the innovation quality incentive (IQI) implemented in the UK. The IQI was introduced for the first time in the regulatory period 2005-2010 only for CAPEX allowances (Crouch, 2006) and extended to other types of costs in the last regulatory period (2010-2015) (OFGEM, 2009c). OFGEM constructs a matrix comprising different profit-sharing regulatory contracts for electricity distribution. The specific regulatory contract which applies to each DSO depends on the ratio of the DSO's cost estimation over the regulator's one (Crouch, 2006). Strictly speaking this mechanism is not a set of finite regulatory contracts, but a continuum of contracts where the power of the incentives decreases with the previous ratio. Hence, undesirable discontinuities in regulation are mitigated.

The diffusion of menu regulation could be expected due to its theoretical advantages and the existing, apparently positive, experience in the UK. The implementation of similar schemes in other countries should obviously be done according to the specific situation. However, this has not been the case so far. One of the major difficulties presumably lies in the lack of clear guidelines to construct the aforementioned matrix of contracts. According to (Crouch, 2006), which provides extensive details about OFGEM's experience in the firstly regulatory period the IQI was implemented, iterative calculations would be needed to ensure incentive compatibility. Therefore, one of the main goals of this chapter is to provide clearer guidelines for its implementation.

Nevertheless, the following proposal will address not only the regulation of new investments, but also the overall revenue determination process. Thus, the determination of the RAB, annual revenue computation and the revision at the end of each regulatory period will be analyzed. The proposal intends to create an investment-friendly environment by means of a forward-looking regulation that acknowledges for the presence and effects of DER and new technologies, whilst promoting efficiency gains, mitigating the regulatory burden on regulators and DSOs, and encouraging a more active participation of DSOs in regulation. The starting point will be unbundled DSOs regulated through an individual revenue cap formula with regulatory periods of at least 5 years. Then, the following actions to be taken by regulators will be analyzed in subsequent sections:

1. Determining the RAB at the beginning of the regulatory period (RAB_0)
2. Calculating the new investments and OPEX allowed over the next years
3. Defining the remuneration formula and computing the annual DSO revenue allowances
4. At the end of the period, review the behaviour of the DSO and make any necessary ex-post correction to the remuneration

5.2.1 Determining the initial regulatory asset base (RAB_0)

The regulatory asset base is the amount of net assets considered by the regulator as the basis for the calculation of the CAPEX remuneration for each distribution company. The methodology that should be followed to determine the RAB at the beginning of each regulatory period essentially depends on the particular circumstances of each country at the time the price review is carried out. Theoretically, two opposing approaches can be found, namely book values or purchase costs and replacement or duplication costs. An extreme implementation of the duplication cost concept is the new replacement value (NRV) used in Latin American countries under the model firm approach (Gómez, forthcoming).

In principle, book values are preferable over duplication costs as creating stranded costs can be avoided. However, implementing book values in practice can be hard and burdensome considering that some investments may be over 30 years old, past information may not be 100% reliable due to changes in the regulatory framework, technology, firm ownership or heterogeneous accounting rules. Moreover, the regulator may doubt that some of the past investments could be deemed efficient or decide that consumers should not pay for certain investments that despite the fact that they could have been considered efficient in the past but, are not "used and useful" nowadays (Kahn, 1988)[33]. Under these circumstances, book values may be over-compensating some firms at the expense of ratepayers. Nevertheless, presumably the most relevant implication of the asset valuation approach selected is related to how costs evolve over time. If the asset remuneration is higher than present costs, firms may earn too high returns or overinvest, whereas the cash flows generated by CAPEX remuneration may be insufficient to drive investments under the opposite circumstances (Kahn, 1988).

[33] In the introduction added to the new edition, the author presents as an example the case of the construction nuclear power in the US that unexpectedly faced increasing costs due to rising inflation and new security requirements set after the Three Mile Island accident. For those plants that remained unfinished, the regulator decided to allow investors to earn depreciation but not to receive any return on capital. Therefore, the burden of the large deviations between past and present costs was shared among investors and ratepayers.

In practice, several intermediate RAB valuation methods have been developed to attain a balance in the existing simplicity and cost-reflectivity tradeoff. The most relevant approaches are depicted in Figure 5-2. Since in many cases the gross assets are computed, it is also necessary to assume the remaining regulatory lives of assets to compute the RAB (net assets), either by estimating the average life of assets or assuming new assets (replacement).

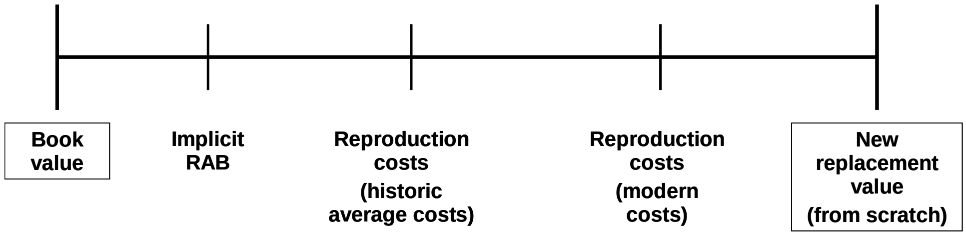

Figure 5-2: Main approaches to calculate the RAB

A very simple alternative to book values is the calculation of the **implicit RAB**. The only input data that are required are the initial distribution revenues, the share of CAPEX over total distribution revenues, the average age of assets, the regulatory asset life and the WACC. The mere multiplication of the two first parameters would provide the total initial CAPEX remuneration for each DSO. The remaining input data allow estimating the RAB as shown in equations 5-1 to 5-4. The major drawback of this approach is that it must be assumed that the initial CAPEX remuneration is adapted to the real RAB of the firms.

$$CAPEX = D + RAB \cdot WACC = \frac{GA}{Life} + WACC \cdot \frac{Life - Age}{Life} \cdot GA \tag{5-1}$$

$$CAPEX = \frac{GA}{Life} \cdot \left(1 + WACC \cdot \left(Life - Age\right)\right) = D \cdot \left(1 + WACC \cdot \left(Life - Age\right)\right) \tag{5-2}$$

$$D = \frac{CAPEX}{1 + WACC \cdot \left(Life - Age\right)} \tag{5-3}$$

$$RAB = \frac{CAPEX - D}{WACC} \tag{5-4}$$

Where:

$CAPEX$	Annual CAPEX allowance
D	Annual depreciation remuneration
GA	Gross assets implicit in the CAPEX remuneration
$Life$	Regulatory life of assets
Age	Average age of assets

Closer to a NRV one may find the network **reproduction cost**, sometimes referred to as the replacement cost of existing infrastructure. This method essentially consists in computing the gross assets through the inventory information and some unit costs determined by the regulator. These standard unit costs can correspond either to the historical purchase costs averaged across DSOs and updated to present prices or the current purchase costs. The former option is closer to a book value valuation whereas the latter is closer to the NRV. In any case, reproduction costs introduce elements of yardstick competition among DSOs in terms of the costs of inputs. Moreover, this approach presents some of the advantages of a duplication cost approach with the mitigation of the risk of creating stranded costs as in the NRV methodology.

Evaluating the asset base requires significant efforts from both the regulator and DSOs and may lead to litigations. Therefore, instead of reassessing the RAB at the beginning of every regulatory period, the regulator could decide to include in the RAB the non-depreciated investments already allowed in previous regulatory periods. This is known as consolidating the RAB. This approach mitigates regulatory instability and reduces the regulatory burden as only the investments corresponding to the last regulatory period are subject to regulatory scrutiny. However, this method usually can only be applied up to a certain point in the past, before which it is necessary to evaluate the whole RAB through one of the other methods described. This can be caused either by lack of data or due to financial issues.

Consolidating assets does not require such a detailed accounting as book values. It is just needed to define a general RAB structure, i.e. the different asset categories to be considered. For each one of these classes a distinct regulatory life of assets and WACC can be defined. Then the regulator would have to keep track of the additions and depreciation for every year and asset category. Table 5-1 shows an example of a possible structure for the RAB of an electricity distribution company.

Asset category	Regulatory asset life	WACC
Lines/transformers	40	8%
Control centres/communications	20	8%
Protections/measuring equipment	10	8%
Smart grid investments	15	9%

Table 5-1: Example of RAB structure definition

The previous approach could be further simplified by computing periodically, e.g. at the beginning of each regulatory period, an equivalent remaining life of assets for each category so as to avoid keeping a detailed track of the investments made, for instance, 20 years ago. Note that this equivalent life of assets cannot be calculated as the weighted average of the remaining life of the investments made in different years. This will be illustrated with a simple case of two investments, namely A and B, that have the same regulatory asset life but were made in different years. The goal is to obtain an equivalent remaining life of the assets that, when applied to the sum of the net (depreciated) assets A and B would yield the same depreciation as computing separately the depreciation corresponding to both net assets. This is shown in equation (5-5).

$$\frac{AB_a}{Life_a} + \frac{AB_b}{Life_b} = \frac{AB_a + AB_b}{Life_{eq}} \qquad (5\text{-}5)$$

Where:

AB Net assets or asset base

Life Remaining regulatory life of a certain investment

$Life_{eq}$ Equivalent regulatory asset life for several investments made in different years

It is straightforward to obtain that such an equivalent life would be as in (5-6), which is clearly different to the weighted average remaining regulatory asset life ($Life_{wa}$) shown in

(5-7). This formula can be easily extended to any number of years and different investments.

$$Life_{eq} = \frac{Life_a \cdot Life_b \cdot (AB_a + AB_b)}{Life_a \cdot AB_a + Life_b \cdot AB_b} \qquad (5\text{-}6)$$

$$Life_{wa} = \frac{Life_a \cdot AB_a + Life_b \cdot AB_b}{AB_a + AB_b} \qquad (5\text{-}7)$$

Nonetheless, it is still required to take into account when certain assets become fully depreciated in order to retrieve them from the RAB and the computation of depreciation allowances. Otherwise, DSOs would still be paid the depreciation of these assets beyond the regulatory asset life. This problem could worsen if asset replacement costs are included in the remuneration, thus leading to a double payment. All these issues are shown more clearly in the example in Table 5-2. The example depicts the annual updates of the RAB and the calculation of the CAPEX remuneration during a period of years that would result by applying three different methodologies: weighted average life of assets, detailed calculation of the depreciation and the equivalent life of assets.

In the example, it is assumed that at the beginning of the period, there are three sets of assets with different remaining regulatory lives of 2, 15 and 25 years respectively. Additionally, the company does not make new investments during the years under analysis. The RAB is updated annually by subtracting the depreciation, calculated according to the three methods previously described. It can be seen that the weighted average life method provides incorrect results, i.e. different to the detailed depreciation approach. On the other hand, the equivalent asset life approach provides the same results with a simpler calculation method for the first two years. However, the table shows that after year 3 results diverge because one of the assets has become fully depreciated.

Net investment	Remaining life
1000	2
15000	15
20000	25

Average life	20,2
Leq	15,7
WACC	8%

Weighted average life

	Year 0	Year 1	Year 2	Year 3	Year 4
RAB	36000	34217,3	32434,7	30652,0	28869,3
Depreciation		1782,7	1782,7	1782,7	1782,7
CAPEX		4520,1	4377,4	4234,8	4092,2

Detailed depreciation

	Year 0	Year 1	Year 2	Year 3	Year 4
RAB	36000	33700	31400	29600	27800
Depreciation		500	500	0	0
		1000	1000	1000	1000
		800	800	800	800
CAPEX		4996	4812	4168	4024

Equivalent life

	Year 0	Year 1	Year 2	Year 3	Year 4
RAB	36000	33700	31400	29100	26800
Depreciation		2300	2300	2300	2300
CAPEX		4996	4812	4628	4444

Table 5-2: Comparison between weighted average asset life, detailed depreciation calculation and equivalent asset life

Since the situation may be very different from one country to another, the most suitable approach depends on each particular case. Nevertheless, whenever possible, it is recommended to consolidate the asset base as this approach provides greater regulatory stability. In order to reassess the RAB while avoiding enduring book revisions, any of the previous methods can be applied or even a mixture of reproduction and replacement costs. The implicit RAB approach is appropriate when the initial remuneration is considered to properly reflect the actual RAB and the focus is placed on the simplicity of regulation. Otherwise, reproduction costs or mixed approaches should be used. In case an inventory is not available or incomplete, the NRV must be calculated, at least partially. For example, since Spanish DSOs have not incorporated the LV assets to their inventories, a NRV is calculated for this voltage level with a greenfield RNM when computing the allowed revenues.

Two issues intimately related to the evaluation of the asset base are the regulatory depreciation method used and the determination of the rate of return (usually a WACC) (Gómez, forthcoming). These aspects are very relevant since, for example, the level of the regulatory WACC and its differences with the actual financing costs faced by DSOs may have important consequences for network investments. Nonetheless, a detailed analysis of the effects of alternative approaches fall outside the scope of this thesis. Hereinafter, it will be generally assumed that a linear depreciation is applied to all assets, except when referring to accelerated depreciation methods which can be done by treating as OPEX certain CAPEX or by shortening their regulatory asset life. Concerning the WACC, it will be assumed that the same WACC is set for all DSOs within a country. Regulators generally have to estimate several parameters such as the gearing ratio, the costs of debt (risk free rate, debt premium), the cost of equity (market risk premium, equity beta) or tax considerations.

5.2.2 Allowance of new investments: menus of contracts

As mentioned in the introduction to this section, the proposed scheme is based on an ex-ante revenue allowance determination with an ex-post review based on ex-ante rules over the overall DSO revenues. More specifically, the approach combines a sliding scale mechanism with a menu of contracts. This type of regulatory scheme is not at all new since it was firstly applied to electricity distribution in DPCR4 for the UK as described in (Crouch, 2006), and also applied in DPCR5 (OFGEM, 2009c).

Nonetheless, an in-depth analysis of how to determine the different parameters that need to be determined as well as their implications in regulatory terms is missing. In particular, the main contribution made herein is the definition of simple and clear guidelines for the construction of the menu matrix avoiding iterative calculations, which according to (Crouch, 2006) were allegedly necessary, and facilitating regulatory decisions. Moreover, a discussion on how to determine the regulators' estimation of investment needs is presented.

5.2.2.1 How the scheme works

Essentially, the use of a menu of contracts complies with the proposal made in (Cossent et al., 2009) as to provide DSOs with an ex-ante budget with full discretion to spend and perform an ex-post evaluation of whether investments have been actually carried out. In this case, the ex-ante budget is determined by combining the regulator's estimate of efficient expenditures with the DSO's prognoses. Moreover, the rules to perform the ex-post correction are fixed ex-ante in order to avoid regulatory uncertainty due to potential clawback fears. This is done through a profit-sharing or sliding scale mechanism whose parameters depend on the ratio of the DSO's forecast to the regulator's estimate. All this is done ensuring incentive compatibility, i.e. DSOs are encouraged to provide truthful estimates of investment needs.

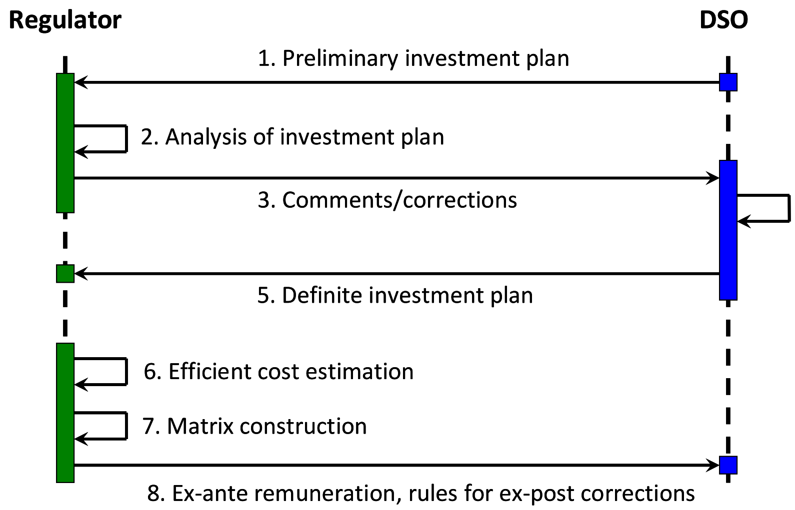

Figure 5-3: Menus of contracts: ex-ante actions

The overall operation of the menu system at the beginning of the regulatory period is depicted in Figure 5-3. Firstly, the regulator asks DSOs to submit their year-by-year investment plans appropriately justified following some pre-defined criteria. These criteria and the ones followed to evaluate the different investment plans should not focus exclusively on the technologies or types of investments, but on the expected impact on network users: quality of service, losses, connection, etc. In order to avoid the problems of input regulation, OFGEM states that these plans should have a clear focus on the outputs that DSOs are expected to deliver and a long-term view by discussing alternative investment plans and the consequences this may have for current and future network users (OFGEM, 2010b). Lastly, DSOs should detail how the uncertainties over demand and generation could affect their investment plans (OFGEM, 2010b). In order to achieve this, and prevent burdensome processes, the length of regulatory periods should not be too short.

Once the companies have submitted the definite investment plans, reflecting any possible comments made from the regulator, the menu matrix and cost baseline are determined. These two actions will be described in detail in sections 5.2.2.2 and 5.2.2.3 respectively. Hence, the following explanations will assume that the matrix and regulator baseline have already been defined. At this point, a matrix similar to the one presented in Table 5-3 will have been obtained. Note that this matrix is the one used by OFGEM in DPCR5 with a slight modification of the additional income, where the sharing factor corresponds to OFGEM's incentive rate. All the numbers are expressed as percentages of the regulator's revenue forecast, except for the sharing factor which represents the share of the difference between ex-ante allowances and actual costs borne by the DSO.

Ratio DSO/Regulator	95	100	105	110	115	120	125	130	135	140
Allowed revenues	98,75	100	101,25	102,5	103,75	105	106,25	107,5	108,75	110
Sharing factor	63,8%	60,0%	56,3%	52,5%	48,8%	45,0%	41,3%	37,5%	33,8%	30,0%
Additional income	3,7	3,0	2,2	1,3	0,3	-0,8	-1,9	-3,2	-4,5	-6,0
85	12,5	12,0	11,3	10,5	9,5	8,3	6,8	5,3	3,5	1,5
90	9,3	9,0	8,5	7,9	7,0	6,0	4,8	3,4	1,8	0,0
95	6,1	6,0	5,7	5,3	4,6	3,8	2,7	1,5	0,1	-1,5
100	2,9	3,0	2,9	2,6	2,2	1,5	0,7	-0,4	-1,6	-3,0
105	-0,3	0,0	0,1	0,0	-0,3	-0,8	-1,4	-2,3	-3,3	-4,5
110	-3,5	-3,0	-2,7	-2,6	-2,7	-3,0	-3,5	-4,1	-5,0	-6,0
115	-6,7	-6,0	-5,5	-5,3	-5,2	-5,3	-5,5	-6,0	-6,7	-7,5
120	-9,8	-9,0	-8,3	-7,9	-7,6	-7,5	-7,6	-7,9	-8,3	-9,0
125	-13,0	-12,0	-11,2	-10,5	-10,0	-9,8	-9,7	-9,8	-10,0	-10,5
130	-16,2	-15,0	-14,0	-13,1	-12,5	-12,0	-11,7	-11,6	-11,7	-12,0
135	-19,4	-18,0	-16,8	-15,8	-14,9	-14,3	-13,8	-13,5	-13,4	-13,5
140	-22,6	-21,0	-19,6	-18,4	-17,3	-16,5	-15,8	-15,4	-15,1	-15,0

Table 5-3: Example of menu matrix

Depending on the ratio of the costs estimated by the DSO over the forecast of the regulator, this matrix allow computing for each DSO the ex-ante revenue allowance and the parameters that will be applied when performing the ex-post adjustment, namely the sharing factor and the additional income. The former parameter is the share of the total cost deviations with respect to the ex-ante allowed revenues that the DSO is exposed to and the additional income is just a lump sum paid to the DSO which ensures that the matrix remains incentive compatible. For example, Table 5-4 shows how these parameters would be obtained for five different DSOs applying the matrix in Table 5-3.

DSO	A	B	C	D	E
Regulator forecast [thousand €]	58568.40	35632.80	8494.56	2500.44	793.69
DSO estimation	70000	50000	9000	2500	750
Ratio DSO/Regulator [%]	119.5	140.3	106.0	100.0	94.5
Ex-ante revenues [%]	104.9	110.1	101.5	100.0	98.6
Ex-ante revenues [thousand €]	61426.3	39224.6	8620.9	2500.3	782.8
Sharing factor	45.4%	29.8%	55.5%	60.0%	64.1%
Additional income	-0.64	-6.10	2.04	3.00	3.77
Additional income [thousand €]	-376.05	-2172.26	173.38	75.08	29.91

Table 5-4: Computation of ex-ante revenue allowance and the ex-post adjustment parameters

It is worth remarking that both the ex-ante allowed revenues and the additional income shown in the table correspond to the amount that DSOs should receive during the entire regulatory period. Therefore, this amount has to be distributed along all the years of the regulatory period. In principle, there could be many different ways to do this, being the simplest ones to set an equal value every year or sharing the amount proportionally to the share of the investments made every year according to the investment plans submitted by each DSO. The latter option could make cash flows be in line with the financing needs of the companies, although this effect can be diluted when setting the overall annual remuneration and X factor. This will be addressed in section 5.2.4. The additional revenue can be treated as an OPEX to be recovered during the regulatory period.

Note that this scheme is quite flexible regarding what cost components are included. The regulator could implement this scheme either only for new investments, which is the main application proposed herein, or to a broader range of cost components, e.g. including network-related OPEX. When applied to new investments alone, the sliding scale can be applied to determine the assets that are eligible to be included in the RAB. On the other hand, when both CAPEX and OPEX are included within the sliding scale mechanism, the regulator must determine certain rules to convert investments into annual allowances. For example, OFGEM introduced the concept of fast and slow money in DPCR5 which consists in assuming that 15% of expenditures are fully recovered in the year of expenditure (fast money) similarly to OPEX and the remaining 85% is added to the RAB and recovered throughout 20 years (slow money) (OFGEM, 2009b).

Until now, the actions taken at the beginning of the regulatory period have been described. Nevertheless, the most interesting features of the proposed mechanism can be seen ex-post under different possible outcomes. As shown in Figure 5-4, the ex-post adjustment to the initial remuneration is carried out at the end of the regulatory period once the actual expenditures incurred by each DSO are communicated to the regulator.

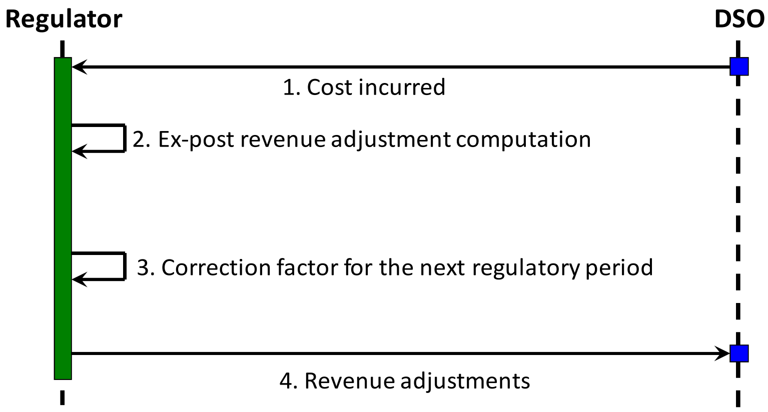

Figure 5-4: Menus of contracts: ex-post actions

If the matrix is correctly constructed, these ex-post corrections should be made in such a way that every firm would be better-off (receive a higher benefit) when the actual expenditures coincide with their ex-ante estimation. It can be seen that the maximum over each row of the matrix (cells shadowed in blue in Table 5-3) are found on the point where actual expenditures coincide with the ratio. Thus, the incentive to inflate the investment estimation that is present in purely ex-ante regulation is eliminated. Additionally, DSOs would still be encouraged to reduce costs if possible and, in case of overspending, would see their risks mitigated due to the limited exposure. This is demonstrated in Table 5-5 (data taken from Table 5-3).

	Inflated DSO estimation	Reference	Cost reduction
Regulator's estimate [M€]	250	250	250
DSO's estimate [M€]	300	275	275
Ratio DSO/Regulator	120	110	110
Sharing factor [%]	45	52.5	52.5
Additional income [%]	-0.8	1.3	1.3
Allowed expenditure [M€]	105% · 250 = **262.5**	102.5% · 250 = **256.25**	102.5% · 250 = **256.25**
Actual expenditure [M€]	275	275	250
Actual efficiency incentive [M€]	45% · (262.5-275) = **-5,625**	52,5% · (256.25-275) = **-9.844**	52,5% · (256.25-250) = **3.281**
Additional income [M€]	-0.8% · 250 = **-2**	1.3% · 250 = **3.25**	1.3% · 250 = **3.25**
Final remuneration [M€]	275 - 5,625 - 2 = **267.375**	275 - 9,844 + 3,25 = **268.41**	250 + 3,281 + 3.25 = **256,531**

Table 5-5: Mitigating the incentive to overestimate expenditures while promoting efficiency

The figures in the first two columns (excluding the text column) show the final revenue of a DSO under two different ex-ante estimations with the same actual expenditure. Let us assume that the DSO tried to inflate its forecast from 275 M€ (2nd column) to 300 M€ (1st column) expecting a higher remuneration. It can be seen that for the same level of actual expenditure, the DSO receives a higher remuneration when the forecast turned out to be more accurate. Thus, the system is incentive compatible. Furthermore, the third column represents the same DSO with a forecast of 275 M€ in expenditure, which in this case it has been able to reduce its expenditures down to 250 M€. Comparing the second and third columns, it can be seen that, under these circumstances, the DSO would receive a higher differential between actual costs and revenue allowances. Hence, efficiency incentives remain in place. Note that if this DSO had forecasted this potential cost reduction ex-ante, its revenues would have been higher.

Summing up, the main advantages of the menu of contracts approach described above can be summarized as follows:

- **Incentive compatible:** DSOs are encouraged to provide detailed and accurate estimation of their investment needs over the whole regulatory period. Consequently, the asymmetries of information are decreased and the potential incentive to inflate the ex-ante estimations is mitigated.
- **Participation of DSOs:** DSOs are involved into the regulatory decisions and their own viewpoints taken directly into account when determining their remuneration. This can help reduce complaints and litigations, which oftentimes accompany price reviews.
- **Efficiency incentives and risk mitigation:** the profit sharing factor provides DSOs with strong incentives to increase efficiency and reduce costs while limiting the exposure of DSOs to investments above the initial allowances. Therefore, once deemed justified and approved by the regulator, DSOs are ensured the recovery, at least partly, of investments in smart grid technologies.
- **Lowers regulatory uncertainty:** any ex-post correction to account for cost deviations is carried out according to predetermined rules, hence decreasing regulatory uncertainty and encouraging investments.
- **Output based and long-term focused investment plans:** the requirement to deliver detailed investment plans with the corresponding justification and explanations allow shifting towards an output-based and long-term focused regulation of investments. Thus, it can be ensured that DSOs consider innovative investments and the presence of DER into their investment plans.
- **Practical experience:** the existing of practical experience in the successful implementation of a similar scheme may facilitate its acceptance by DSOs and other stakeholders.
- **Reopeners:** since the investments plans submitted by DSOs should already consider uncertainty sources and their potential effects, the definition of reopeners is made an easier and more objective task for regulators. This can be particularly relevant to react to rapid changes in demand conditions or technologies. For instance, important changes in power flow patterns may occur due to a rapid connection of DG derived from the introduction of stronger incentives to install DG or to purchase EVs.

5.2.2.2 Constructing the matrix

One of the major difficulties in the implementation of the menus of contracts is the construction of the matrix in such a way that it is incentive compatible. The regulator has to set three parameters for every level of the ratio DSO/Regulator: the revenue allowance, the additional income and the sharing factor or incentive rate. The revenue allowance should increase with the ratio, whereas the sharing factor must decrease. Thus, companies with more capabilities of cost reduction will choose a lower revenue allowance with stronger efficiency incentives and vice versa (Joskow, 2006). Lastly, the additional income is set with the exclusive aim of attaining incentive compatibility.

However, details as to how this can be done are scarcely available. The reader is referred to page 130 in (OFGEM, 2009d) and page 111 in (OFGEM, 2009c) to see two examples of incentive compatible matrices, although accompanied by little clarification about their construction. (Crouch, 2006) presents some further details on how the matrix used in UK's DPCR4 was computed. Therein, the revenue allowance is calculated through equation (5-8), where the discretionary parameters 105 and 0.25 represent the revenue allowances at the point with a DSO/Regulator ratio of 100 and the weight given to the excess of costs estimated DSOs with respect to the regulator's forecast. These two parameters could be set separately.

$$Allowance = 105 + (Ratio - 100) \cdot 0.25 \qquad (5\text{-}8)$$

The sharing factor (*SF*) is also defined as a linear function of the ratio, where the intercept is once again the value corresponding to a DSO/Regulator ratio of 100 and the slope denotes how the incentive strength (magnitude of the sharing factor) decreases with the ratio.

$$SF = 0.4 - (Ratio - 100) \cdot 0.005 \qquad (5\text{-}9)$$

The additional income (*AI*) is only said to be set through a non-linear function of the DSO/Regulator ratio. Moreover, the author states that "*it may necessary to iterate through these three steps to ensure that the overall combination achieves the property of being incentive compatible*".

However, the detailed calculations that can be found in the "financial issues" excel spreadsheet published by OFGEM[34] (*"IQI"* tab) shows that iterations may not be required once the appropriate parameters have been computed. In this document, it can be seen that the sharing factor is calculated as a linear function of the ratio (5-10) and the additional income as a quadratic function of the ratio (5-11). The first parameter in (5-11) is fixed exogenously (intercept), whereas the other two parameters are computed as shown in Table 5-6 from the remaining parameters. Nonetheless, no justification for the formulas applied is given.

$$SF = 1 - 0.005 \cdot Ratio \qquad (5\text{-}10)$$

$$AI = 2.5 + 0.125 \cdot Ratio - 0.00125 \cdot Ratio^2 \qquad (5\text{-}11)$$

[34] See associated document at:

http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=371&refer=Networks/ElecDist/PriceCntrls/DPCR5

Cell	Parameter	Value	Formula
A	Incentive rate (slope)	-0.005	-
B	Incentive rate (intercept)	1	-
C	Allowed expenditure (slope)	0.25	-
D	Allowed expenditure (intercept)	75	-
E	Additional income (second order parameter)	-0.00125	E = A·(0,5 - C)
F	Additional income (first order parameter)	0.125	F = - A·D - B·C
G	Additional income (intercept)	2.5	-

Table 5-6: Computation of matrix parameters according to OFGEM's financial issues spreadsheet

Hereinafter, some clearer guidelines to the determination of incentive compatible matrices that do not require iterative processes will be described. The formulas required to obtain all the parameters of the matrix, equivalent to those used by OFGEM, will be derived analytically when necessary. Additionally, the regulatory implications of each of the discretionary parameters that have to be defined will be discussed so that their fixation can be more transparent and justifiable. The same three steps followed mentioned in (Crouch, 2006) will be followed:

1. **Allowed revenues:** the ex-ante allowed revenues can be determined as a weighted sum of the estimates provided by regulator and DSOs estimates, as shown in equation (5-12). This is similar to the Chilean approach to determining the added value of distribution (VAD)[35], where a weight of 2/3 was given to the estimation of the regulator and a 1/3 weight to that of DSOs (CNE, 2006). In fact, the same revenue allowances found in matrix used by OFGEM for DPCR5 would be obtained by placing a 75% weight on the regulator's estimation. If the regulator wants to provide some additional revenue to DSOs, as done in (5-8), this can be done through the additional income.

$$AR = \omega \cdot 100 + (1 - \omega) \cdot Ratio \tag{5-12}$$

Where:

AR	Allowed revenues, as a percentage of the regulator's estimation [%]
ω	Weight given to the revenue estimation of the regulator [pu]
$Ratio$	Ratio of the DSO's estimation over the regulator's estimation [%]

2. **Sharing factor:** the same linear function of the DSO/Regulator ratio implemented by OFGEM will be followed due to its simplicity and the fact that the discretionary parameters have a direct interpretation. A generalized formula is shown in (5-13). The regulator would have to fix the reference value and the slope of the linear function. The former represents the sharing factor for a value of the ratio of 100, can be interpreted as the profit sharing parameter that would be used by the regulator in case DSOs where offered a single simple sliding-scale regulatory contract. On the other hand, the rate of change reflects how the power of the efficiency incentive is mitigated the higher the revenue allowance asked for by the company is. Therefore, this parameter will always be negative.

$$SF = SF_{ref} + (Ratio - 100) \cdot SF_{roc} \tag{5-13}$$

Where:

[35] The VAD is the name given to the tariff component that accounts for the cost of distributing electricity in Chile and other South American countries.

SF	Sharing factor
SF_{ref}	Reference value for the sharing factor (value for a *Ratio* of 100)
SF_{roc}	Slope or rate of change of the sharing factor with *Ratio*

3. **Additional income:** the additional income is computed as a function of the DSO/Regulator ratio in such a way that incentive compatibility is achieved. In order for the matrix to be incentive compatible, the maximum value for each row must be attained at the point where actual expenditures equal the DSO/Regulator ratio.

   In principle, any functional form that complies with the condition that incentive compatibility can be achieved for any level of expenditures may be used for the additional income. Nonetheless, it is not straightforward to find a function that complies with this condition (assuming the parameters ω and SF_{roc} remain constant with the DSO/Regulator ratio). A linear function would be the simplest approach. Nonetheless, as demonstrated in annex C, it would be impractical for the additional income to be computed as a linear function of the DSO/Regulator ratio because the weight ω would have to be fixed at 0.5. Otherwise, attaining incentive compatibility would not be possible

   Therefore, non-linear functions must be applied. For the sake of simplicity, the same functional form used by OFGEM has been assumed, i.e. a quadratic function such as the one shown in (5-15). Thus, three parameters ought to be defined, i.e. the function intercept and the first and second order factors. The mathematical derivation of how the parameters in the formula can be calculated as a function of the sharing factor slope and the weight of the regulator's estimate is provided in annex C. The final formulas are presented in (5-15) and (5-16) respectively.

   $$AI = AI_{\text{int}} + \alpha \cdot Ratio + \beta \cdot Ratio^{2} \quad (5\text{-}14)$$

   $$\alpha = SF_{ref} \cdot (\omega - 1) + 100 \cdot SF_{roc} \cdot (1 - 2 \cdot \omega) \quad (5\text{-}15)$$

   $$\beta = SF_{roc} \cdot (\omega - 0.5) \quad (5\text{-}16)$$

   It is worth remarking that the incentive compatibility can be achieved for any value of the intercept in the additional income formula, provided that the other parameters are computed through the previous formulas. However, the intercept, as defined in (5-14) does not have any direct regulatory meaning. It would merely be the value of the additional income for a null value of the DSO/Regulator ratio, which would never happen in real life. Therefore, it is proposed to let the regulator set a reference value that corresponds to the value of the additional at the point where the ratio is 100. The intercept of equation (5-14) would then be obtained as a function of the previous parameters as shown in (5-17). The reader is referred to annex C for further details.

   $$AI_{\text{int}} = AI_{ref} - 100 \cdot SF_{ref} \cdot (\omega - 1) + 10^{4} \cdot SF_{roc} \cdot (\omega - 0.5) \quad (5\text{-}17)$$

Table 5-7 summarises the parameters required to build an incentive compatible matrix of regulatory contracts. It can be seen that under the proposed approach, the regulator would have to set four discretionary parameters; one to compute the revenue allowance (weight given to the regulator's forecast), two to calculate the sharing factor (reference value and slope) and another one for the additional income (reference value). The remaining parameters would be computed following the equations previously obtained.

Parameter symbol	Description	Discretionary	Formula/constraint
ω	Weight on regulator's estimate	Y	$\in$ [0,1]
SF_ref	Reference value for sharing factor	Y	-
SF_roc	Rate of change of sharing factor with ratio	Y	< 0
AI_ref	Reference value for additional income	Y	-
AI_intercept	Intercept of additional income formula	N	AI_ref-100·SF_ref·(ω-1)+10^4·SF_roc·(ω-0.5)
α	1st order factor of additional income formula	N	SF_ref·(ω-1)+100·SF_roc·(1-2·ω)
β	2nd order factor of additional income formula	N	SF_roc·(ω-0,5)

Table 5-7: Summary of the parameters required to build an incentive compatible matrix

Note that the equivalent matrices could be constructed by using different discretionary parameters and calculating the remaining solving the previous expressions for them. However, the formulation of the problem proposed above has been done in such a way that the regulator directly decides on those parameters that have an actual meaning and regulatory implications.

5.2.2.3 Computing the regulator's estimation

The estimation made by the regulator of the efficiently incurred costs is essentially the same process as the one followed to determine the ex-ante revenue allowances in conventional revenue cap regulation. As described in chapter 4, some form of regulatory benchmarking is generally used for this task. A detailed discussion on the main pros and cons of the main benchmarking approaches will be presented in chapter 6. Nonetheless, the review previously presented has shown that there does not seem to be a generally superior approach over others. Moreover, further research and experience on the use of different benchmarking tools is necessary. Additionally, the characteristics of the distribution sector in the system/country that is going to be regulated are also very relevant. For example, performing econometric benchmarking may be hampered by a reduced number of DSOs (the issue of international benchmarking was already discussed in chapter 4).

The main advantage of the menu system over a conventional revenue cap approach is that the adverse selection problem in the ex-ante revenue estimation is partly mitigated by the fact that the firm is encouraged to provide accurate cost estimations. Additionally, the uncertainty the regulator (and DSOs) has over its cost estimate and the capabilities of DSOs to reduce them could be reflected in the discretionary parameters chosen to build the menu matrix. When the regulator (and DSOs) faces high uncertainties over the future costs of the companies, a lower weight on its estimate (ω) can be used, together with a higher slope of the sharing factor. In essence, this would be bringing the regulatory contract closer to a cost of service regulation. Since this may be the case during the transition towards smarter distribution grids, regulators could start by designing low powered contracts in the beginning and increasing the strength of incentive schemes over time as both regulators and DSOs gather experience.

Nevertheless, whilst the menu system mitigates the incentive to overestimate investment needs, DSOs may still try to influence the regulator forecast so as to increase its revenue forecast as in any ex-ante regulation. In practice, DSOs may have several means to game regulators which also depend on the benchmarking model used (Jamasb et al., 2003). Table 5-8 (built with data from Table 5-3) depicts two situations, one in which the regulator’s cost estimation obtained through benchmarking analyses is 250 M€, and another where the DSO has presumably managed to make the regulator increase its cost estimation from 250 M€ to 275 M€. It can be seen that in both cases, the actual DSO expenditures are the same and equal to the DSO’s cost estimation. The results obtained clearly show that DSOs may have strong incentives to influence the regulator’s ex-ante revenue allowance.

Regulator's estimate [M€]	250	275
DNO's estimate [M€]	275	275
Ratio DSO/Regulator	110	100
Sharing factor [%]	52.5	60
Additional income [%]	1.3	3
Allowed expenditure [M€]	102.5% · 250 = **256.25**	100% · 275 = **275**
Actual expenditure [M€]	275	275
Actual efficiency incentive [M€]	52,5% · (256.25-275) = **-9.844**	60% · (275-275) = **0**
Additional income [M€]	1.3% · 250 = **3.25**	3% · 275 = **8.25**
Final remuneration [M€]	275 - 9,844 + 3,25 = **268.41**	275 + 0+ 8,25 = **283,25**

Table 5-8: Effects of gaming the regulator in menu of contracts regulation

5.2.3 Regulating other distribution costs

Until this point, the main focus of the proposals has been placed on the regulation of capital expenditures. This is because CAPEX and investment regulation constitute the major challenges in the case of network industries. Notwithstanding, DSOs also incur in significant operation and maintenance costs, which may be related either with the network activities or other activities such as metering, as well as other costs (e.g. taxes). However, no major recommendations for the regulation of OPEX and other costs will be made here. Essentially, the regulator must determine which of these costs can be considered controllable and which fall outside the control of DSOs.

Controllable OPEX should be subject to benchmarking and could be added to CAPEX in the menu of contracts mechanism. The main advantage of this is that it avoids creating distinct incentives for OPEX and CAPEX reductions that may lead to gaming or inefficiencies (Jamasb and Pollitt, 2001; Jamasb et al., 2003). This can become particularly relevant under significant penetration of DER and smart grid technologies because potential tradeoffs between OPEX and CAPEX solutions will presumably intensify. On the contrary, as mentioned above, including both OPEX and CAPEX in the menu scheme requires defining some rules to calculate the annual revenue allowances and perform the ex-post corrections on TOTEX.

In any case, to the extent possible, the OPEX allowances should be consistent with the allowed capital expenditures. Moreover, taxes and non-controllable OPEX should be excluded from efficiency scrutiny and recouped by means of a cost pass-through.

5.2.4 Remuneration formula and computation of annual revenues within the regulatory period

The remuneration formula proposed is a conventional revenue cap updated every year through an RPI-X factor. The ex-ante revenue allowances should include those allowed under the menu of contract scheme (distributed along the regulatory period, for instance proportionally to the DSO plan), the additional income (treated as an OPEX), the allowed costs pass-through and the revenue stream generated by the initial RAB.

Table 5-9 shows how the revenue allowances could be distributed throughout the regulatory period. In this example, it has been assumed that the menu scheme only applies to investments. Both the additions to the RAB and the additional income have been distributed proportionally to the investment plans submitted by the DSO. The ratios to determine the allowed revenues and the additional income have been drawn from Table 5-3. If the regulator wishes to include both OPEX and CAPEX within this mechanism, the overall revenue allowances should be split into RAB additions and OPEX allowances through a predefined sharing factor.

Regulator's estimate [M€]	4000
DSO's estimate [M€]	4800
Ratio DSO/Regulator	120
Allowed investments share	105
Allowed investments [M€]	4200
Additional income share	-0.8
Additional income [M€]	-32

	Year 1	Year 2	Year 3	Year 4	Total
Investments per year (DSO plan) [M€]	1000	2000	1300	500	4800
Share of investments per year according to DSO plan	20.8%	41.7%	27.1%	10.4%	100.0%
RAB additions allowed per year ex-ante	875	1750	1137.5	437.5	4200
Additional income	-6.7	-13.3	-8.7	-3.3	-32.0

Table 5-9: Distribution of ex-ante revenue allowances throughout the regulatory period

Furthermore, the application of the menu of contracts may result in an ex-post correction to the allowed revenues in the previous regulatory period. This correction factor, equal to the sharing factor times the difference between the actual and allowed expenditures, should also be included in the remuneration of this period. The starting RAB (year 0) would be computed through one of the methods described in section 5.2.1. In case menus of contracts were used in the previous period, the investments finally allowed made in the previous regulatory period should be included. Further details about the ex-post adjustment are provided in section 5.2.5.

Since the efficiency incentives are already embedded within the menu of contracts, the X factor will be used to smooth DSO revenues along the regulatory period rather than as an efficiency requirement[36] (Gómez, forthcoming). Thus, the X factor can be computed in such a way the net present value of non-smoothed allowed costs equal the net present value of the smoothed ex-ante revenues. This will result in balanced cash flows for DSOs and tariff stability.

The calculation of the smoothing X factor and annual revenues for a DSO is illustrated in Table 5-10 for a four-year regulatory period. Note that the data from Table 5-9 have been included in this example. The monetary units are assumed to be million € (red figures are input data). Note that a negative X factor, when computed this way, does not imply that DSOs are not required to achieve efficiency gains because efficiency requirements are embedded within the ex-ante allowed OPEX and investment calculations.

[36] In fact, the conventional interpretation of the X factor as an efficiency gap that ought to be reduced is difficult to implement in practice, especially when technologies changes or significant investments are necessary.

	REGULATORY ASSET BASE	Year 0	Year 1	Year 2	Year 3	Year 4
A	Opening RAB		10000.00	10131.55	11079.76	11377.56
B	Investments		875	1750	1137.5	437.5
C	Depreciation		743.45	801.79	839.70	854.29
	Closing RAB (A+B-C)	10000	10131.55	11079.76	11377.56	10960.77
	DEPRECIATION	**Regulatory asset life**	**Year 1**	**Year 2**	**Year 3**	**Year 4**
	Existing assets	14	714.29	714.29	714.29	714.29
	Investments year 1	30	29.17	29.17	29.17	29.17
	Investments year 2	30		58.33	58.33	58.33
	Investments year 3	30			37.92	37.92
	Investments year 4	30				14.58
	Investments year 5	30				
	Total depreciation		743.45	801.79	839.70	854.29
	OPEX		**Year 1**	**Year 2**	**Year 3**	**Year 4**
	Allowed OPEX (include efficiency requirements)		250	300	220	200
	Additional income		-6.7	-13.3	-8.7	-3.3
	WACC		7.5%	7.5%	7.5%	7.5%
	ALLOWED REVENUES		**Year 1**	**Year 2**	**Year 3**	**Year 4**
	Return on investment (WACC * RAB)		759.87	830.98	853.32	822.06
	Depreciation		743.45	801.79	839.70	854.29
	OPEX		243.33	286.67	211.33	196.67
	Total revenues		1746.65	1919.43	1904.35	1873.01
	SMOOTHED REVENUES	**Year 0**	**Year 1**	**Year 2**	**Year 3**	**Year 4**
	Smoothed revenues	1900	1882.18	1864.53	1847.04	1829.71

NET PRESENT VALUE ANALYSIS	
VAN Allowed revenues	6,221.18
VAN Smoothed allowed revenues	6,221.18
NPV difference	- 0.00
Smoothing X Factor	0.94%

Table 5-10: Calculation of smoothing X factor (neglecting inflation)[37]

The X factor and the initial revenues are parameters that can be used by the regulator to determine different revenue paths, either increasing or decreasing, to control the DSOs' cash flows or the variation of network tariffs between consecutive regulatory periods (Green and Rodríguez-Pardina, 1999). When it is desired to mitigate the price changes between regulatory periods, the initial revenues should be consistent with the remuneration in the last year of the previous regulatory period and set the X factor as required to meet the expected future costs (left part of Figure 5-5). On the contrary, if the regulator prefers to reduce the gap between remuneration and actual costs much faster, the alternative shown in the left part of Figure 5-5 ought to be adopted.

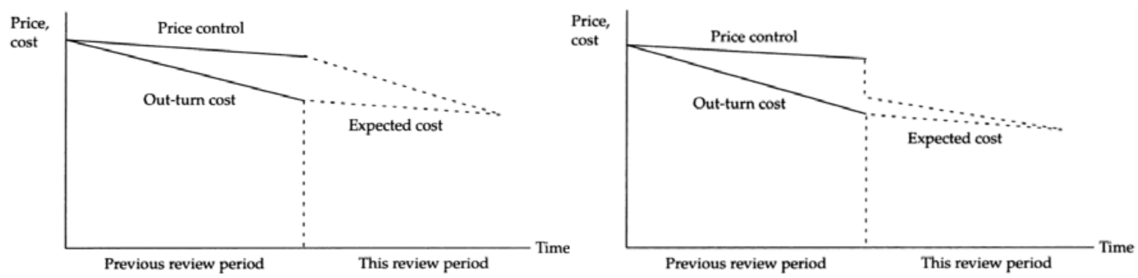

Figure 5-5: Smoothed revenue path vs. one-off price adjustment (Green and Rodríguez-Pardina, 1999)

[37] The closing RAB is considered when computing the return on investments for simplicity reasons. This would mean that it is being implicitly assumed that all investments within one year are carried out at the beginning of that year. A more usual approach would be to compute the return on investments as the average of the starting and closing RABs times the rate of return.

5.2.5 Ex-post revenue adjustments

All the actions described above have to be performed at the beginning of the regulatory period. Nonetheless, at the end of each regulatory period actual expenditures are to be compared against the ex-ante allowances in order to perform any necessary revenue adjustment. This adjustment can be computed as the product of the NPV of the additional CAPEX remuneration, both in terms of depreciation and return on assets, received due to under expenditures (or the loss of CAPEX remuneration due to over expenditures) times the sharing factor. Following the same example used in section 5.2.4, Table 5-11 shows how the ex-post revenue adjustment would be calculated when the DSO invests less than initially allowed in the first year of the regulatory period.

Sharing factor	0.45
WACC	7.5%
Regulatory asset life	30

		Year 1	Year 2	Year 3	Year 4
RAB additions per year allowed ex-ante		875	1750	1137.5	437.5
Actual investments per year		800	1750	1137.5	437.5
Difference (under-spend) [M€]		75	0	0	0
Differences in closing RAB		75	72.5	70	67.5
Depreciation difference [M€]	Inv. year 1	2.5	2.5	2.5	2.5
	Inv. year 2	-	0	0	0
	Inv. year 3	-	-	0	0
	Inv. year 4	-	-	-	0
Total depreciation difference [M€]		2.5	2.5	2.5	2.5
Return on investments difference [M€]		5.63	5.44	5.25	5.06
Total CAPEX difference [M€]		8.13	7.94	7.75	7.56
NPV of CAPEX difference [M€]		10.85	9.86	8.96	8.13

Total NPV of CAPEX difference	37.80
Adjustment to be made in next period	**17.01**

Table 5-11: Ex-post revenue adjustment through a menu of profit-sharing contracts

After the previous calculation is made, the revenue adjustment is treated as an OPEX in the beginning of the next regulatory period. Note that it would not be necessary to distribute this adjustment over the period so as to prevent tariffs volatility when the smoothing X factor approach is used. Moreover, the opening RAB for the next period has to be determined. As mentioned above, consolidating the RAB with actual investments is deemed the most suitable approach provided that adequate reliable information is available. Notwithstanding, the regulator could retain the power of disallowing certain RAB additions in case these are deemed useless or imprudent.

5.3 Implementation in a specific context: the case of Spain

The electricity distribution network assets in Spain are shown in Table 5-12[38]. Distribution companies supply over 28 million point of supply with a contracted capacity

[38] The data has been estimated from the Annual Electricity Statistics published by the by the Ministry of Industry, Energy and Tourism at: http://www.minetur.gob.es/energia/balances/Publicaciones/ElectricasAnuales/Paginas/ElectricasAnuales.aspx

of around 145.5 GW[39]. The total annual electricity consumption at distribution level in 2010 was around 243 TWh (CNE, 2012a). A total of 342 DSOs[40] own and operate the Spanish distribution network, although the biggest five of them supply almost all the electricity demand (CNE, 2012a). These main DSOs are geographically distributed as shown in Figure 5-6. Moreover, only seven DSOs supply more than 100000 consumers, thus most DSOs in Spain fall under the unbundling exemption included in the EU electricity Directive (European Communities, 2009). These small DSOs are currently regulated in a different way from major DSOs and will not be considered in the subsequent analysis.

LV lines (0.4kV)	Overhead [km]	402.774
	Underground [km]	62.449
MV/LV transformers	Number	310497
	Capacity [GW]	119
MV lines (1-33 kV)	Overhead [km]	358189
	Underground [km]	80750
HV/MV transformers	Number	4.145
	Capacity [GW]	103
HV lines (45-132 kV)	Overhead [km]	66.966
	Underground [km]	2.341

Table 5-12: Distribution assets in Spain estimated for the year 2009

Figure 5-6: Geographical distribution of the five major DSOs in Spain (CNE, 2012a)

In the remainder of this section, the case of Spain will be studied so as to describe how the previous regulatory approach could be implemented in a specific context. The period 2009-2012 will be analyzed in detail and several regulatory amendments will be proposed. Hereinafter, the current Spanish regulation will be evaluated in order to

[39] Data for the year 2010. Obtained from the information about quality of service provided by the Ministry of Industry, Energy and Tourism at: https://oficinavirtual.mityc.es/eee/Conexion/SubMenu.aspx?loc=24

[40] Data for July 2012. The updated full list of DSOs is available at: https://oficinavirtual.mityc.es/eee/indiceCalidad/distribuidores.aspx

characterize the regulatory processes and tools used as well as the main weaknesses. Subsequently, a proposal for modifying current regulation will be developed and the main potential benefits to be expected will be enumerated.

5.3.1 A critical assessment of current regulation

The legislation passed in the year 2008 introduced a new regulatory framework for electricity distribution companies. The remuneration formula and how to determine of allowed revenues are defined in RD 222/2008 (Ministry of Industry Tourism and Trade, 2008). The remuneration formula, defined in Article 8 of the RD, is a revenue cap with four-year periods (5-18). DSO revenues are modified annually through an update index that accounts for inflation and efficiency requirements. This update factor is equal for all DSOs. Additionally, the incentives to improve continuity of supply and reduce energy losses are included in the remuneration with a one-year lag. Lastly, a term (Y factor) reflecting the increment in costs resulting from the demand growth in year n-1 is calculated ex-post an added to the allowed revenues in year n (Cossent et al., 2011a). This factor is computed with the expansion-planning RNM described in chapter 4.

$$R_n^i = \left(R_{n-1}^i - Q_{n-2}^i - L_{n-2}^i\right)\cdot\left(1 + IA_n\right) + Q_{n-1}^i + L_{n-1}^i + Y_{n-1}^i \quad (5\text{-}18)$$

Where:

R^i_n	Allowed revenues of DSO i in year n [€]
Q^i_n	Continuity incentive of DSO i in year n [€]
L^i_n	Losses incentive of DSO i in year n [€]
IA_n	Update factor (inflation and efficiency) in year n [pu]
Y^i_n	Cost increment due to load growth in the area of DSO i in year n [€]

The so-called update index is calculated as the weighted sum of the retail price index (IPC in Spanish) and an industrial price index, both evaluated for the month of October in the previous year (n-1). As shown in (5-19), these price indices are affected by efficiency factors, a different one for each index. The values for x and y in the period 2009-2012 were set at 0.8% and 0.4% respectively. Nonetheless, the RD does not report any methodology to estimate or update these parameters.

$$IA_n = 0.2\cdot\left(IPC_{n-1} - x\right) + 0.8\cdot\left(IPRI_{n-1} - y\right) \quad (5\text{-}19)$$

The revenues for the first year of the regulatory period are computed using the same formula in (5-18), using as starting point the revenues in a hypothetical year 0 obtained as show in (5-20). The parameter R_{ref} is called reference remuneration and it is determined by the regulator.

$$R_0^i = R_{ref}^i \cdot (1 + IA_0) \quad (5\text{-}20)$$

Where:

R_{ref}	Reference remuneration of DSO i [€]
IA_0	Update factor for the year before the start of the regulatory period [pu]

For the regulatory period 2009-2012, the reference remuneration was computed by calculating the increment in remuneration that each DSO would experience as a result of the actual load growth in their area (first additional statement of RD 222/2008). The scale factors represent the per-unit increment in distribution costs driven by a per-unit increase in the demand served. These parameters were computed for each DSO using the RNMs as explained in (CNE, 2007). The factor of 1.028 can be interpreted as an update factor, albeit no explicit mention of this is made. The remuneration for 2007 that was included in this formula did not correspond to the actual allowed revenues in that year, but to certain values published in the same RD (first additional statement). No further justification of these values was included in the RD.

$$R^i_{0-2008} = R^i_{2007} \cdot 1.028 \cdot \left(1 + \Delta D^i_{2007} \cdot Fe^i\right) \tag{5-21}$$

Where:

ΔD^i_{2007} Annual average load growth in 2007 in the area of DSO i [pu]

Fe^i Scale factor for DSO i [pu]

It can be seen that the mechanisms to encourage DSOs to gain in efficiency or to determine the RAB that should be embedded in the computation of the initial allowed revenues or the X factors were not adequately described in the RD. Nonetheless, a detailed proposal for the computation of the reference remuneration is described in Article 7 of the RD, seemingly to be applied in subsequent regulatory periods. Therein, it is proposed to compute the reference remuneration as the sum of investment costs, comprising linear depreciation and a return on investment computed through a representative WACC (same for all DSOs); O&M costs and other distribution costs such as billing, metering, etc. The two last terms would be benchmarked across DSOs using the information from the regulatory accounting system.

$$R^i_{ref} = IC^i_{ref} + OMC^i_{ref} + ODC^i_{ref} \tag{5-22}$$

Where:

IC^i_{ref} Remuneration of investment costs of DSO i [€]

OMC^i_{ref} Operation and maintenance costs of distribution assets of DSO i [€]

ODC^i_{ref} Other distribution costs of DSO i [€]

In March 2012, the energy regulator issued a report to the Ministry of Industry, Energy and Tourism proposing several measures to tackle the tariff deficit existing in the Spanish power sector (CNE, 2012b). Therein, a critical evaluation of the economic regulation of DSOs in Spain was presented. Several measures to amend current regulation were delivered, both for the short and the medium term. The short-term measures aimed at reducing the costs borne by end-consumers in the immediate years. These comprised subtracting the assets already depreciated from the remuneration of the cost of capital, which was not contemplated in RD 222/2008, and updating the allowed OPEX in line with the cost reductions achieved by DSOs.

The medium-term measures contained more comprehensive and profound regulatory changes. The report urged for a revision of the incentives to improve quality of service, adding mandatory requirements on meter reading periodicity, and energy losses. Nevertheless, the major recommendations were related to the determination of the reference remuneration and the annual update of the allowed revenues. The regulator's report advocated for the introduction of the concept of RAB into the Spanish regulation. Consequently, the CAPEX remuneration would be updated annually considering new investments and the depreciation of assets. Additionally, it is stated that DSOs should elaborate ex-ante yearly investment plans for the whole regulatory period that would be assessed by using the RNM. Note that Article 4.2 of RD 222/2008 already mandates DSOs to submit these investment plans. However, their use in regulation is quite unclear as they are not explicitly taken into account when determining the allowed revenues. The allowed revenues would be corrected ex-post according to certain rules fixed ex-ante. Finally, CNE suggested a revision of the allowed OPEX to account for efficiency gains and the reduction in metering costs thanks to the implementation of AMR and AMM.

In conclusion, it can be seen that the Spanish regulatory framework for electricity distribution presents several intrinsic deficiencies and lacks significant methodological justifications. Considering the framework defined in RD 222/2008 and the regulator's analysis on measures to reduce the tariff deficit previously described, the following shortcomings have been identified:

– A methodology to define the RAB to be considered in the determination of the reference remuneration is required and in the annual update of DSOs remuneration.

– New investments were added to the remuneration, but no subtraction of depreciation was made. This could lead to excessive CAPEX allowances. Nonetheless, asset replacement investments were not explicitly included in the Y factor in formula 5-27, thus mitigating the deviation between CAPEX allowances and actual costs. Hence, a more clear methodology to determine new investment needs, including network expansion and asset replacement investments, is required.

– The Y factor that accounts for new investments required to meet growing demand is calculated annually with a one-year lag. The frequent revisions and ex-post nature of this term deter create regulatory uncertainty and deter DSOs from planning their networks with a long-term view or even from investing at all. Moreover, this imposes a significant burden on the regulator as the RNM has to be run every year for all DSOs. Finally, in case the RNM alone is used to compute this Y factor irrespectively of the actual investments of the firms, this can create incentives to game the regulator or may lead to litigation against the use of the model.

– DSOs are required to periodically elaborate detailed investment plans. However, these are not considered in the determination of allowed revenues.

– The values for the efficiency factors x and y included in the update index (5-19) are set in the RD without further justification. It should be clearly stated that these factors should be determined according to efficiency criteria or to smooth the annual allowed revenues over the regulatory period. Moreover, the regulator should be able to modify the actual values of these parameters between regulatory periods, which may not be possible if these are fixed in a RD.

5.3.2 Proposed implementation

Several of the drawbacks of Spanish distribution regulation identified in the previous subsection, can be solved through the implementation of some of the proposals presented in section 5.2. The proposed amendments will focus on the computation of the reference remuneration, and more specifically the RAB, as well as the implementation of menus of contracts for new investment requirements.

5.3.2.1 Computing the reference remuneration

The method to compute the reference remuneration essentially consists in implementing the proposed formula included in Article 7 of RD 222/2008 (5.31). This formula comprises three terms, one accounting for CAPEX remuneration, and two accounting for OPEX (asset maintenance and other costs).

Regarding CAPEX, following the CNE recommendation, the concept of RAB should be introduced into the Spanish regulation. Among the potential approaches for its determination, in section 5.2.1 it was stated that asset consolidation provided higher stability and regulatory certainty. Moreover, asset consolidation is advisable should one desire to implement the menu of contracts approach for new investments. Nonetheless, the actual situation of Spain has to be considered when determining the best approach to compute the RAB. Up to now an adequate record of investments and depreciation seems to be missing. For example, the regulator itself in the aforementioned report on measure to tackle the tariff deficit (CNE, 2012b) used the implicit RAB approach in its calculations.

In spite of its simplicity, the implicit RAB method relies on the assumption that current remuneration is adapted to the actual asset bases of DSOs. However, considering the lack of justification of the figures provided in the first additional statement of RD 222/2008 and subsequent documents issued by the Ministry of Industry, Energy and Tourism, it is hard to evaluate the accuracy of this assumption. Therefore, for the sake of transparency, it is proposed to perform an in-depth revision of the RAB, at least for the first regulatory period, through a combination of reproduction and replacement costs. The approach suggested derives from the concept of relative reference networks in (Paulun et al., 2008). The proposed approach intends to benefit from the existing experience in the use of RNMs in Spain together with the inventories of DSOs, which have been considerably improved during the last regulatory period. The implementation proposed herein would follow these three steps:

1. Calculate an asset reproduction cost by considering the assets from DSO inventories at the beginning of the regulatory period and the unit costs that are audited and used by the regulator as an input to run the RNM.
2. Calculate an asset replacement value by using the greenfield RNM. The model used in Spain allows fixing the location of the substations to avoid too large deviations between the topology of actual and reference grids. The input data would correspond to the load conditions at the beginning of the regulatory period. For the remaining non-network assets, other form of reference benchmarking or a reproduction cost approach would be followed.
3. Lastly, similar to the Chilean approach in (CNE, 2006), both values would be combined to obtain the starting RAB for the regulatory period. However, contrary to the Chilean case, a fixed weight for both asset base estimations will not be used. Instead, the concept of relative reference networks described in (Paulun et al., 2008), and already presented in chapter 4 of this thesis, will be applied. The proposed implementation is illustrated in Table 5-13 with five hypothetical DSOs. The main idea is to compare the two cost estimations. The DSO whose reproduction cost is closer to the replacement cost will be remunerated according to the former, whereas the rest of DSOs will paid a percentage of the reproduction costs that will decrease homothetically with the difference between both cost estimations.

DSO	Reproduction cost [M€]	Replacement cost [M€]	Ratio replacement to reproduction cost	Difference in % of reproduction cost	Share of reproduction included in RAB
A	2500	1980	79,20%	20,80%	85,96%
B	1780	1450	81,46%	18,54%	88,22%
C	740	690	93,24%	6,76%	100,00%
D	600	510	85,00%	15,00%	91,76%
E	3200	2960	92,50%	7,50%	99,26%

Table 5-13: Relative reference networks to determine the RAB

The main advantage of relative reference networks over fixed weights is that, in addition to the efficiency signal deriving from the use of the RNM, some form of yardstick competition is introduced. Hence, the distortions caused by the historical evolution of the actual grids that cannot be taken into account in a greenfield RNM are mitigated.

A final consideration that must be made is that the proposed method may, in some cases, yield a higher RAB than the implicit RAB approach. This can be particularly true for those DSOs whose reproduction cost is very close to the replacement cost. Owing to the need to avoid cost increases in order to mitigate the tariff deficit problem, these cases should be identified and proper corrections made. Notwithstanding, the risk of finding these situations is minimized if the results obtained through the previous methodology are corrected for asset depreciation. Doing this, the resulting method would be a hybrid between the relative reference network approach in (Paulun et al., 2008) and New Zealand's ODRC described in chapter 4.

5.3.2.2 Implementing the menus of contracts

Two of the major drawbacks of current Spanish regulation identified in section 5.3.1 were that the frequent ex-post revisions deterred an efficient long-term network development and that the investment plans elaborated by DSOs were not taken into account to determine their remuneration. The menu of contracts approach previously described would be suitable to address these problems, while benefiting from the experience gained in the use of RNMs to regulate electricity distribution utilities. Two main questions arise in the implementation phase, i.e. how to construct the menu matrix, and how to determine the regulator's revenue estimation.

1. What values ought to be used to construct the menu matrix?

As described in subsection 5.2.2.2, the regulator would have to set just four discretionary parameters when constructing the menu matrix. The weight placed on the regulator's estimation should depend on how reliable this forecast is. In order to facilitate the acceptance of the menu system by DSOs, during the first regulatory period, this parameter could be set close to a 60%. Regarding the remaining parameters, it must be born in mind that one of the major concerns of the Spanish regulator nowadays is to reduce the costs of the power system and mitigate uncertainty of future prices. Hence, a high value for the slope of the sharing factor and relatively low additional incomes would be preferred. Nonetheless, a very low value for the reference sharing factor should not be set so as not to discourage efficiency gains.

The final values used should be chosen by the regulator according to the information available at the price review. Table 5-14 shows a possible matrix that fulfils the previous characteristics.

Ratio DSO/Regulator	95	100	105	110	115	120	125	130	135	140
Allowed revenues	98	100	102	104	106	108	110	112	114	116
Sharing factor	55.0%	50.0%	45.0%	40.0%	35.0%	30.0%	25.0%	20.0%	15.0%	10.0%
Additional income	3.5	2.5	1.5	0.4	-0.7	-1.9	-3.1	-4.4	-5.7	-7.1
85	10.6	10.0	9.1	8.0	6.6	5.0	3.1	1.0	-1.4	-4.0
90	7.9	7.5	6.9	6.0	4.9	3.5	1.9	0.0	-2.1	-4.5
95	5.1	5.0	4.6	4.0	3.1	2.0	0.6	-1.0	-2.9	-5.0
100	2.4	2.5	2.4	2.0	1.4	0.5	-0.6	-2.0	-3.6	-5.5
105	-0.4	0.0	0.1	0.0	-0.4	-1.0	-1.9	-3.0	-4.4	-6.0
110	-3.1	-2.5	-2.1	-2.0	-2.1	-2.5	-3.1	-4.0	-5.1	-6.5
115	-5.9	-5.0	-4.4	-4.0	-3.9	-4.0	-4.4	-5.0	-5.9	-7.0
120	-8.6	-7.5	-6.6	-6.0	-5.6	-5.5	-5.6	-6.0	-6.6	-7.5
125	-11.4	-10.0	-8.9	-8.0	-7.4	-7.0	-6.9	-7.0	-7.4	-8.0
130	-14.1	-12.5	-11.1	-10.0	-9.1	-8.5	-8.1	-8.0	-8.1	-8.5
135	-16.9	-15.0	-13.4	-12.0	-10.9	-10.0	-9.4	-9.0	-8.9	-9.0
140	-19.6	-17.5	-15.6	-14.0	-12.6	-11.5	-10.6	-10.0	-9.6	-9.5

Table 5-14: Matrix with a possible menu of contracts for Spain (ω=0.6, SF_{ref}=50%, SF_{roc}=-0.01, AI_{ref}=2.5)

2. How is the regulator's estimation computed?

First of all, the regulator should determine what costs are included under the mechanism. Network related costs, both CAPEX and OPEX, could be easily included within the incentive scheme since these are controllable costs which the regulator has been monitoring over the last regulatory period and some standard costs have been already been audited and used to run the RNMs. Nevertheless, the regulator may opt for including only CAPEX during the first regulatory period and incorporate OPEX in subsequent periods so as to facilitate the transition. As explained in the previous section, the latter alternative would require defining a sharing factor to divide total expenditures into CAPEX and OPEX, e.g. OFGEM utilized a 15%-85% OPEX-CAPEX division in DPCR5. In the case of Spain, the regulator already resorted to such a ratio when computing the implicit RAB of DSOs in (CNE, 2012b), which corresponded to a 35%-65% assignment of OPEX-CAPEX.

Capital costs should include not only the costs driven by load growth and new connections but also the asset replacement costs. Assets that are built by third-parties but operated by DSOs should not be included in CAPEX allowances. Other expenditures related, for instance, with control centres or buildings could be included provided that these can be considered controllable. Non-controllable costs should be excluded from the incentive system and be recovered through a pass-through.

Hereinafter, the emphasis will be placed on network-related costs since they constitute the most relevant cost component and the harder to analyze. The main tool to obtain the regulator's estimation is suggested to be the expansion-planning RNM. The remaining controllable costs could be benchmarked across DSOs using the regulatory accounting information. Despite the fact that this partial benchmarking can fail to capture existing tradeoffs between alternative expenditure alternatives, RNMs are deemed to capture more easily the heterogeneity across distribution areas and the effects of new DER connections. Running this model requires defining the initial network that will be taken as a starting point, the load and generation scenarios that will be analyzed and define the standardized library of equipment that will be used.

In order to estimate the real investment needs as accurately as possible, the initial grid used to run the expansion-planning model should correspond to the actual assets operated by each DSO. Therefore, this initial grid would be constructed on the basis of the inventories of DSOs. Those assets that are put out of service and should be replaced must be excluded from this initial grid. Therefore, the assets retired should be specified within the investment plans submitted by DSOs, something which is not explicitly stated in RD

222/2008. Thus, the models would provide both the network costs driven by load growth and by asset replacement.

An estimate of load growth and connections of new network users is required to determine investment needs. DSOs should be the ones providing this information since they have the most complete information. Hence, the investment plans submitted at the beginning of the price review should contain this type of information. Nonetheless, significant deviations could occur throughout the regulatory period, particularly with DG penetration as this is much more uncertain and subject to the design of regulatory incentives for CHP and RES. Moreover, as described in subsection 5.2.2.3, DSOs could try to inflate their load prognoses should they think that this could result in a higher revenue estimation of the regulator. Notwithstanding, this incentive is much less important than in a purely ex-ante regulation. These problems can only be mitigated by defining certain thresholds on variables such as load growth or number of connections (per DSO, region, etc.) which if surpassed would trigger a partial revision of the revenue estimations.

Additionally, how DER (DG, EVs or demand response) are modelled when running the RNM can influence the results (Cossent et al., 2010; Conchado, 2011; Cossent et al., 2011b; Mateo and Frías, 2011; Pieltain Fernandez et al., 2011; Yap, 2012). Through the modelling assumptions, DSOs could be implicitly encouraged to incorporate the potential contribution of DER in network planning. This is an issue that will become more relevant in the long-term. Nonetheless, it would be necessary to provide appropriate mechanisms for DSOs to contract out services from DER, such as the mechanism described in (Trebolle et al., 2010) for DG or the ones proposed in (Belhomme et al., 2009) for consumers.

Another issue related to the previous one that should be considered is whether network users pay deep or shallow connection charges and, in the former case, whether these costs are included or not in the revenue allowances. The costs recouped through connection charges should not be included in the revenue determination when this is used only to define the use-of-system charges. Therefore, when network users pay deep connection charges and these are excluded from the allowed revenues included in the remuneration formula (an in the case of Spain), the RNM should be run in such a way that it is avoided to remunerate these costs twice. This can be achieved by using the coordinates of the point of connection instead of the actual location of network users. Nonetheless, when the previous installations are operated by DSOs, operation and maintenance costs should be remunerated to DSOs.

Lastly, the regulator should pay attention to the library of standardized equipment (lines, transformer, protections, etc.) that is used as an input to the RNM. These data comprise technical information (overhead/underground, voltage level, capacity, failure rate) as well as economic information (investment cost, maintenance cost). Technical information should adequately characterize the real investment alternatives that DSOs may find. On the other hand, the cost information should correspond to efficient unit investment costs benchmarked across DSOs. Thus, using the RNM would encourage DSOs to carry out efficient investments, whereas using the same library of equipment for all DSOs would encourage them to make these investments at efficient costs.

5.3.2.3 Remuneration formula and calculation of annual revenues

Firstly, the length of regulatory periods could be extended to at least 5 years to provide DSOs with a longer term view. In order to mitigate the effect of uncertainties, the regulator could set several conditions under which the price review could be partially reopened due to, for example, abnormal load growth, significant change in financial conditions, sudden technological changes, etc.

Furthermore, it would be needed to change the remuneration formula on (5-18) to the one shown in (5-23). The update factor used in this case only includes price effects, as a weighted sum of the two price indices currently used (see 5-24). On the other hand, the X^* factor is used as smoothing factor as described in section 5.2.4. Efficiency requirements on controllable costs (non-controllable costs should be passed-through) would already be included in the annual revenue allowances used to compute the initial revenues and X^* factor. Moreover, by comparing the two formulas, it can be seen that the ex-post Y factor has been removed from the formula as the investments required during the regulatory period would be already embedded within the annual allowed revenues.

$$R_n^i = \left(R_{n-1}^i - Q_{n-2}^i - L_{n-2}^i\right)\cdot\left(1 + IA_n^* - X^{i*}\right) + Q_{n-1}^i + L_{n-1}^i \qquad (5\text{-}23)$$

Where:

IA_n^* Update factor (inflation only) in year n [pu]

X^* Smoothing X factor during the regulatory period for DSO i [pu]

$$IA_n = W \cdot IPC_{n-1} + (1-W)\cdot IPRI_{n-1} \qquad (5\text{-}24)$$

Where:

W Weight for price index IPC [pu]

$1\text{-}W$ Weight for price index IPRI [pu]

As shown in Figure 5-5, the regulator has two main options when setting the smoothing X factors, either a progressive revenue path or a one-off price adjustment could be made. The latter alternative seems more suitable for the Spanish context given the need to cut power system costs in the short-term in order to tackle the existing tariff deficit.

5.3.3 Advantages expected

The previous regulatory amendments present several potential advantages over the current framework. Among the benefits that could be expected from their implementation, one may mention some of the intrinsic characteristics of the menu system itself, such as the incentive to provide accurate investment plans while promoting efficiency gains. Moreover, the existing experience in the UK with the application of such a scheme mitigates possible implementation risks. Nevertheless, the following benefits can be considered as specific to the Spanish context:

- Much experience in the use of RNM for regulation has been already gathered in Spain. This required regulators to spend significant resources in the development and application of these models and DSOs to revise their databases so as to accommodate to a new regulatory accounting system. The proposed approach builds on this experience and resources, thus not requiring a profound change in regulatory practices and tools. Moreover, RNMs are particularly suitable for the case of Spain where just a few DSOs supply most consumers and these DSOs face very different environmental conditions, e.g. coastal versus mountain areas. These specific conditions seriously hamper the application of black-box benchmarking for CAPEX regulation. This issue will be addressed in more detail in chapter 6.

- Since the RAB is consolidated at the end of each regulatory period, except for the first period after the implementation, price review processes are deeply simplified. Moreover, DSOs perceive higher regulatory stability.
- The investment plans of DSOs are carefully analyzed and taken into account to determine the allowed revenues of DSOs. Hence, DSOs would be actively involved in the price reviews and encouraged to elaborate detailed and adequately justified investment plans. Consequently, price reviews stop resembling a regulator versus DSO game or an actual grid versus reference grid competition.
- The definition of more transparent regulatory methodologies enhances the regulatory stability and credibility perceived by DSOs and prevents potential regulatory capture and problems derived from the Ministry intervention, which may not always be driven by objective technical criteria (Glachant et al., 2012).
- The annual fully ex-post revisions of allowed revenues are substituted by a one-off ex-ante revenue determination at the beginning of the regulatory period together with an ex-post evaluation based on pre-defined rules. This shift to an ex-ante regulation with a horizon of several years mitigates uncertainty and encourages DSOs to carry out a more efficient network development with a longer-term view. At the same time, the ex-post profit-sharing revisions reduce the incentives to overinvest and mitigate regulatory uncertainty.
- Distribution costs are more predictable and stable during the regulatory period. Therefore, the impact of tariff deficit mitigation measures on final retail tariffs, which is critical nowadays in Spain, becomes easier to estimate.
- Under the current remuneration formula, the RNM has to be run every year to obtain the value of the Y factor for each DSO. On the other hand, under the proposed mechanism, RNMs only need to be run at the beginning of the regulatory period. Consequently, the regulatory burden of running the models is significantly reduced.

5.4 Summary and conclusions

The chapter has been devoted to proposing a suitable framework for the determination of the allowed revenues of DSOs in an environment with high uncertainties in the demand and technological sides. Even though a holistic approach has been followed, the focus has been placed on CAPEX remuneration, more specifically on new investment needs. Within the proposed approach, the four chronological steps to follow are:

i. Determine the opening RAB
ii. Calculate the new investment needs and OPEX allowances
iii. Define the remuneration formula and DSO annual ex-ante revenue allowances
iv. Ex-post review of actually incurred costs and computation of revenue adjustments

In principle, adding the investments carried out since the last price review, or the fraction of them deemed efficient, to the RAB should be the preferable alternative in order to avoid regulatory uncertainty. This is known as consolidating the RAB. However, existing information about past investments and current assets may not always be consistent and suitable to reflect the true value of network assets. Consequently, in practice, regulators frequently need to reopen the asset base so as to determine a new starting point during price control processes. There are several methods to evaluate the RAB, being the book value and new replacement value approaches the two extreme methods and existing intermediate approaches. The different alternatives have been presented and compared. Nevertheless, the decision about the most suitable alternative would depend upon each specific context and the information available about the DSOs' assets and cost accounting.

Concerning the remuneration formula, a revenue cap regulatory framework has been selected since this is considered to be better adapted to the characteristics of the electricity distribution sector, particularly under the presence of DER and smart grid technologies. Furthermore, the X factor is computed as a smoothing factor instead of an efficiency factor. This approach gives more flexibility to the regulator in order to define the most convenient revenue path while avoiding large fluctuation in cash flows received by DSOs. Thus, a stable and certain remuneration is provided which implies a more favourable environment to attract investments.

The central mechanism proposed in this thesis is the use of an incentive compatible menu of contracts, which has already been used in the UK to regulate electricity DSOs. However, a deep discussion of how to construct the matrix of contracts was not available in the literature. In this chapter, clear guidelines to obtain such matrices have been provided, including the parameters that have to be defined by the regulator, their regulatory implications and the conditions which ensure incentive compatibility. Under this mechanism, the ex-ante revenue allowances are determined as a weighted average of the investment needs estimated by each DSO and the forecast performed by the regulator on the basis of benchmarking studies. Moreover, an ex-post correction is made depending on the actual expenditures of each DSO by following the formulas embedded within the matrix of menus. This scheme encourages DSOs to provide accurate forecasts of their investment needs while encouraging cost reductions through efficiency gains.

In order to illustrate how such an approach could be implemented, Spain was selected as a case study. Firstly, a critical assessment of the existing remuneration framework has been performed. The major problems identified comprise the fact that the Spanish regulation does not include the concept of RAB, investment allowances are subject to very frequent (annual) ex-post reviews and there is an important lack of transparency on the regulatory decisions. For example, the initial revenue allowances for the latest regulatory period have been published in an annex of a royal decree without providing any justification at all. As a consequence, the current regulation deters DSOs from investing and, according to a recent report issued by the regulator; it has led to an unreasonable increase in the costs of distribution. In order to overcome these limitations, the aforementioned proposals have been adapted to the situation of Spain.

Since the concept RAB is not present in the current regulation, it is not possible to consolidate past investments. Therefore, it seems necessary to re-assess the RAB through any of the existing methods. The regulator has already used the implicit RAB approach for some preliminary calculations. This is a very simple method, albeit it is implicitly assumed that the current remuneration appropriately reflects the actual DSO assets. Given the lack of transparency on regulatory decisions, this assumption presumably does not hold. Therefore, it is proposed to perform an in-depth revision of the RAB, at least for the first regulatory period. Implementing the concept of relative reference networks is proposed. Thus, the RAB is determined by combining a reproduction value, based on DSOs' inventories, and a replacement value, calculated with the greenfield RNM. The relative weight of both estimations depends on the gap between the reproduction and the replacement values. The proposed approach intends to benefit from the experience gained during the last regulatory period.

Lastly, the menu system seems to fit perfectly within the Spanish context since DSOs already have to periodically submit investment plans to the regulator, which are not considered nowadays when determining distribution allowed revenues. Additionally, the incremental RNM can be a powerful tool to help estimate the regulator's forecast for investment requirements. During the first regulatory period, a relatively low-powered matrix with a moderate weight on the regulator's estimation could facilitate the acceptance of this mechanism.

As a result, a modified remuneration formula is obtained. The annual ex-post revenue additions would be removed since now the investment allowances are embedded within the initial remuneration. Moreover, the update factor which accounts for inflation and efficiency gains is substituted by a factor accounting for inflation and a smoothing X factor that can be used by the regulator to determine a suitable revenue path.

The regulatory amendments proposed for the Spanish context can potentially deliver significant benefits. Firstly, the lack of regulatory certainty and transparency is mitigated by removing frequent ex-post reviews by ex-ante assessments which incorporate the viewpoint of DSOs with ex-post adjustments based on predefined rules. Additionally, the menu system together with the use of a smoothing X factor creates a more stable and predictable distribution remuneration. This is a much needed characteristic given the important need of reducing the tariff deficit in Spain over the next few years. Moreover, sudden changes in regulatory practices are avoided since the investment plans already developed by DSOs as well as the use of RNMs are incorporated in the new framework. Lastly, the burden on the regulator within the regulatory period can decrease since the annual revisions, which required significant efforts in data gathering and model running every year, are eliminated.

Main conclusions:

- Consolidating the RAB provides greater regulatory certainty. However, due to the lack of suitable and reliable information, reopening the RAB is frequently needed. The most appropriate method depends on the conditions in each country/region
- Revenue cap remuneration is considered to be more suitable under the presence of DER and smart grid technologies.
- Computing the X factor as a smoothing factor is proposed so as to gain in flexibility when defining the revenue path while avoiding large fluctuation in DSO cash flows.
- Using an incentive compatible menu of contracts to determine DSO revenue allowances, especially network investments, is proposed. This scheme encourages DSOs to provide accurate expenditure forecasts while encouraging cost reductions
- Building of the existing literature, clear guidelines to obtain such matrices have been developed
- Spain has been selected as use case to evaluate the implementation of the previous proposals. A critical assessment of current regulation has allowed identifying several shortcomings which deter DSOs from investing and has presumably led to an unreasonable increase in distribution costs
- The following proposals for the Spanish context were made:

– Perform an in-depth revision of the RAB, at least for the first regulatory period. The proposed alternative is based on the concept of relative reference networks

– A menu system fits within the Spanish context since DSOs already have to periodically submit investment plans to the regulator. The incremental RNM can be a powerful tool to help estimate the regulator’s forecast

– The annual ex-post revenue additions would be removed from the remuneration formula and revenues would be updated following inflation and a smoothing X factor

– Potential benefits include: lower regulatory uncertainty and higher transparency, a more stable and predictable remuneration, avoidance of sudden changes in regulatory practices and decreased regulatory burden

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6. Regulatory benchmarking: critical comparison of approaches

A comprehensive review of the existing benchmarking approaches has been presented in chapter 4. Despite the wide range of methods and experience in their application, there does not seem to be an agreement on the most appropriate tool to use when regulating electricity distribution companies. This question is very relevant to implement any mechanisms such as the one proposed in chapter 5.

In order to shed some light on this, several comparisons among different benchmarking techniques will be presented below: The pros and cons of each method will be highlighted, bearing in mind the new challenges faced by DSOs previously described. These comparisons are relevant in order to understand the limitations of each technique and select the most suitable one or ones for each case.

Firstly, the well-known parametric and non-parametric frontier benchmarking approaches will be discussed in section 6.1, summarising the main topics that can be found in the literature. Secondly, the Spanish RNM and the Swedish NPAM, which are the two main norm models that can be found, will be compared in section 6.2. This will be followed by a discussion about the merits and disadvantages of engineering RNMs against frontier benchmarking methods in section 6.3. These two latter comparisons have not been done in such detail by other authors, presumably due to the lack of understanding between economists and engineers working in the field of regulation (Grifell-Tatjé and Kerstens, 2008). Finally, the chapter ends with some conclusions in section 6.4.

6.1 Comparison of frontier benchmarking methods

Two main categories of frontier benchmarking methods can be found, namely parametric and non-parametric. Owing to the fact that these are the most widely used approaches both in the scientific literature as well as by practitioners, the major pros and cons of the different methods are clearly identified and agreed upon. The main sources for this comparison are (Jamasb and Pollitt, 2001; Agrell and Bogetoft, 2003; Jamasb and Pollitt, 2003).

DEA is generally preferred over parametric methods, especially by regulators, as shown in the reviews presented (Jamasb and Pollitt, 2001) and (Agrell and Bogetoft, 2003). The main reasons for this are that DEA is simpler to apply, more understandable and more flexible. Moreover, it is possible to decompose the efficiency scores obtained into scale and pure technical efficiency as well as measure the frontier shift. Additionally, in non-parametric methods, firms are compared against real firms instead of some statistical estimation. This makes it easier to interpret and justify the efficiency ranking. Furthermore, non-parametric benchmarking requires minimal previous assumptions regarding cost/production functions and technologies. Finally, DEA performs minimal extrapolations and can handle multiple outputs more easily than parametric methods.

On the other hand, the major shortcoming of DEA is that it is very sensitive to outliers, and data errors. The model specification can also significantly influence the results as the number of variables rapidly increases the number of efficient firms or the firm ranking can change when some variables are modified. Therefore, the robustness of its results must be carefully analysed. Finally, performing statistical analyses on the results is not as straightforward as in parametric methods. Nevertheless, as explained in chapter 4, some solutions can be found for these shortcomings such as implementing SDEA, using panel data or performing bootstrapping.

Regarding parametric benchmarking, COLS is relatively simple, although SFA is used more frequently due to its superior behaviour against outliers and noise. The MOLS method is hardly ever mentioned in the literature and, as far as the author is concerned, it has never been applied to assess the efficiency of distribution firms. The main advantages that can be highlighted are that statistical analyses can be easily performed and that the existence of noise and errors in the data is taken into account (in SFA). In regulation, the fact that parametric methods are based on anonymous peers can be desirable as firm to firm comparisons can be avoided (Agrell and Bogetoft, 2003).

However, all parametric methods require the specification of a functional form for the production/cost frontier. Hence, they can lack generality and there is a higher risk of specification error. For example, the parameters estimated may not have engineering significance or some inefficiency may be wrongly considered as noise (in SFA). The quality of the results obtained depend on how well the actual noise and inefficiencies follow the distribution functions assumed for them (Jamasb and Pollitt, 2003).

Summing up, both parametric and non-parametric approaches present advantages and shortcomings. There are no reasons to assume that one approach is essentially superior to the other. As shown in Figure 6-1, the method selection faces tradeoffs which require discretionary decisions by the model user.

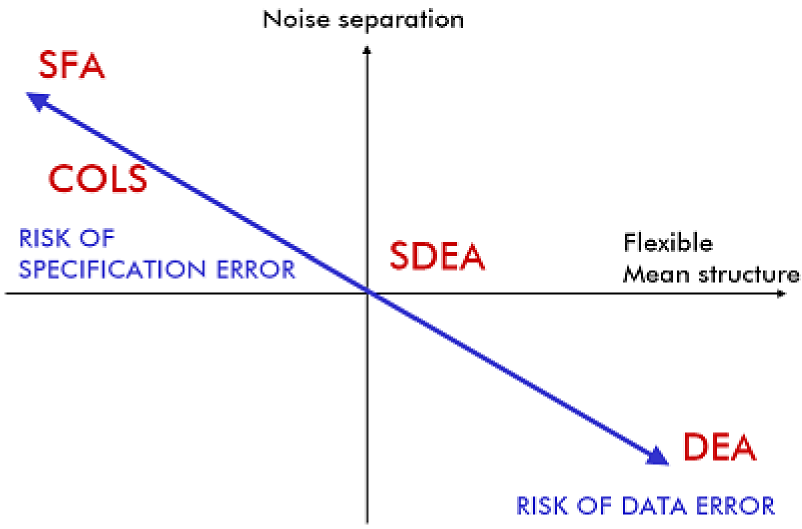

Figure 6-1: Tradeoffs in frontier benchmarking method selection (Agrell and Bogetoft, 2003)

6.2 Comparison of different reference network models

This kind of comparison is scarcely done in the literature as most publications tend to consider all engineering approaches as a homogeneous group, see for instance (Turvey, 2006; Jamasb and Pollitt, 2008). However, it is relevant to highlight that each application is unique. Since the models are not generally made available, it is complicated to perform quantitative comparative analyses, which are indeed possible for frontier benchmarking methods. Thus, only a few qualitative comparative assessments are available, generally made by the authors presenting some kind of reference benchmarking model.

(Larsson, 2005) describe the Spanish and Chilean use of RNMs, albeit the comparative analysis is rather scarce. The author limits the comparison on the fact that both the

Chilean and Spanish models perform optimization, whereas optimization is not carried out in the NPAM. On the other hand, (Ajodhia, 2005) compares the NST with previous engineering models on the basis of two parameters: the overall solution-seeking approach (optimization, simulation, etc.) and whether and how quality of service is taken into account (see Table 6-1). Finally, (Mateo Domingo et al., 2011) simply states the Spanish RNMs are more detailed than NPAM and that, contrary to NPAM, they allow considering the presence of DG.

Model	Basic Approach	Treatment of quality
Sweden (NPAM)	Cascading algorithm	No
Chile	Unknown	No
Spain (BULNES)	Optimisation algorithms	Indirectly
Spain (Peco and Gómez 2000)	Optimisation algorithms	Second stage optimization
NST	Simulation	Integrated with price

Table 6-1: Comparison of reference benchmarking models in (Ajodhia, 2005)

Our comparison is based solely on the descriptions of the Swedish and Spanish models provided in chapter 4. The problems associated with the lack of robustness and the inappropriate regulatory design will not be discussed herein. These two models have been selected since, despite the fact that RNMs have also been used in Chile, it seems that up to now former versions of the Spanish model have been mostly used in this country. Moreover, Ajodhia's NST is not exactly a RNM, but a model based on representative networks.

The use of detailed geographical information permits both models to capture the heterogeneity among the distribution areas served by different companies. However, important differences exist among both models. As mentioned in (Mateo Domingo et al., 2011), the NPAM is less detailed than the Spanish RNMs. The simplifications that may potentially affect more significantly the results obtained, provided that a comparative quantitative assessment could be performed, are the following:

- The NPAM does not consider street maps or geographical constraints. Therefore, the results can be significantly underestimating the cost of the network. For example, (Mateo Domingo et al., 2011) performed a test on an urban area serving one million consumers with and without considering street maps. The test showed that the increase in network length deriving from considering street maps amounted to 17% for the LV grid and almost 38% for the MV grid.
- The technical analyses and the economic evaluation are completely separated in the NPAM. Therefore, the resulting network will be insensitive to potential tradeoffs in costs that may exist. For instance, it may be more economical to build thicker conductors or install more expensive transformers when this allows reducing network losses. Similarly, depending on the cost of network elements, shorter MV networks could be compensated by longer LV conductors and vice versa.
- Despite the fact that (Ajodhia, 2005) states that quality is not considered by the NPAM, this is not the case. Spare capacity is added to the initial radial network in order to reduce the cost of NSE. However, the alternatives to improve reliability are limited to additions of new branches and new transformers, which are considered the same for all voltage levels, and protection equipment is taken as given. The Spanish RNMs, besides these alternatives, also consider the installation of additional protection equipment (sectionalizers, signalizers, breakers, fuses, etc.) and simulates

the location and behaviour of maintenance crews. Additionally, different reliability requirements are set for the MV and the HV grids, which are designed according to the N-1 reliability criterion, following the usual practices in the industry.

- The NPAM considers that all lines are underground cables, thus the actual reliability and cost could be different from the model estimations in case overhead lines are used by actual utilities. On the other hand, the Spanish RNMs can handle both types of lines according to a set of parameters set by the user.
- Finally, continuous cost functions are used in the NPAM. Consequently, the Swedish model neglects the intrinsic lumpiness of investments. This becomes particularly relevant for higher voltage levels. Moreover, these cost function basically depend on load density and voltage level. However, actual costs may depend on many additional issues such as height over sea level, overhead or underground elements, etc.

The main advantage of NPAM over the Spanish RNMs seems to be its lower computational requirements. The main reason why NPAM presents the previous simplifications is that the developers placed the focus on reducing the burden of running the model (Larsson, 2005). On the other hand, running the Spanish RNM to regulate DSOs is performed by powerful dedicated servers due to their computation burden. In addition, several distribution areas are analysed separately and parallel computing techniques are used (Gómez et al., 2012). Nevertheless, the lack of comparative quantitative assessments of both models does not allow drawing definite conclusions.

6.3 Black-box frontier benchmarking and norm models: two apparently opposing views

6.3.1 What the literature says

Frontier benchmarking has become very popular among regulators over the years. More recently, RNMs or norm models have been adopted as an alternative approach to regulate electricity distribution companies. These two types of methods are frequently treated as two opposite approaches to regulation. The former approach is generally advocated by economists, whereas the latter approach is more widely supported by engineers. However, few authors really perform in-depth comparisons among both approaches. This is presumably because economists and engineers do not seem to know in detail each other's approaches (Grifell-Tatjé and Kerstens, 2008), even though a survey presented in (Haney and Pollitt, 2009) show that regulators frequently engage both types of consultants.

Generally, those authors that state that frontier benchmarking is inferior to reference benchmarking tend to see black-box methods as subjective and unreliable. Nonetheless, they also tend to neglect the most advanced developments such as the use of panel data or environmental variables. On the other hand, other authors deem RNMs as being too inflexible and static and limit their applicability to a few cases, for example where data is scarce (Agrell and Bogetoft, 2003; Jamasb and Pollitt, 2008). The ensuing review intends to pave the way for future understanding between advocates of both approaches to regulatory benchmarking. Furthermore, the appropriateness of the different methods in the light of the upcoming challenges faced by DSOs in the next years will be discussed.

Despite the popularity of frontier benchmarking, some authors strongly criticize these methods (Irastorza, 2003; Shuttleworth, 2005). (Irastorza, 2003) states that the application of frontier benchmarking "*is subjective, lacks transparency, foments disputes and puts utilities at financial risk*". Similarly, (Shuttleworth, 2005) states that *"benchmarking has* *proven either troublesome or irrelevant to the regulatory process"*. The basis for the previous assertions can be found in the existing limitations of frontier benchmarking methods. The main shortcoming of frontier benchmarking lies in the fact that the inefficiency computed with any model should not be directly interpreted as such because the results will inevitably reflect to some extent the effect of omitted variables and data errors, regardless of the method used. Therefore, the existence of a large heterogeneity across firms, which is likely to be larger for network activities than in other sectors, undermines the suitability of frontier benchmarking to regulate electricity distribution companies.

The immediate solution for this would be to add more variables to the model. However, the number of variables that can be considered is strongly limited. In non-parametric methods, adding more variables would cause all firms to approach the frontier, whereas in parametric methods problems related to multicollinearity or lack of significance of certain parameters could arise. These problems can be solved by increasing the sample size. However, since the number of firms within a single country can be insufficient to consider a large number of variables, international benchmarking would be required to keep enlarging the number of observations. Nonetheless, doing this, besides other difficulties, worsens the problem as much higher heterogeneity is introduced, thus requiring to increase the sample size even more (Shuttleworth, 2005). The sources of this heterogeneity may be found on geographical and climatic conditions, input prices, environmental regulation, energy policies or the voltage levels comprised in distribution networks. Furthermore, companies outside the jurisdiction of the regulator, but included in the benchmarking sample, cannot offer explanations about the results and provide further information if required to clarify the results (Shuttleworth, 2005).

Additionally, these authors argue that there may be some features that are unique to each DSO that cannot be included in any frontier benchmarking model or that frontier benchmarking shows lack of robustness (see chapter 4 for a deeper discussion about the robustness of frontier benchmarking methods). The last major drawback of frontier benchmarking is that strong discretionary decisions are needed from the regulator in order to translate benchmarking results into revenue allowances over the regulatory period. This is the main reason why frontier benchmarking is seen as being highly subjective in its application. (Irastorza, 2003; Shuttleworth, 2005) illustrate this by comparing the cases of the UK, The Netherlands and New South Wales (Australia).

The previous authors conclude that relying too much on the results of benchmarking is not advisable due to the aforementioned limitations. Notwithstanding, they acknowledge that frontier benchmarking may indeed play a role in regulation, mainly as a preliminary assessment to identify particular aspects or DSOs that should be investigated in more detail by the regulator.

Nonetheless, the previous authors do not provide clear alternatives to the use of frontier benchmarking. (Shuttleworth, 2005) argues that using an estimation of the long-term TFP growth as an X factor applied on current costs, as done in some states of the US, may be a superior (less intrusive) approach to frontier benchmarking. The regulator may only disallow certain costs in "clear-cut cases" through detailed and justified judgement.

However, it is unclear why this alternative is not partially subject to some of the same criticism as frontier benchmarking related to heterogeneity across firms (in case TFP estimates are compared across DSOs), need to identify inputs and outputs and translate them into common units (input and output prices), need of tight informational requirements, discretionary decisions from the regulator (even if reduced, they would still be needed), etc. It seems that part of the difficulties in benchmarking would be overcome by not assessing the efficiency at all. Nevertheless, some further knowledge and tools seem necessary to address asymmetries of information. Furthermore, the TFP approach may be unsuitable in situations when significant investments are required to upgrade or modernise the grid, when technologies change rapidly or when the operating environment is changing due to the connection of DG or EVs, as it is envisioned for the coming years.

Consequently, it seems difficult to completely avoid resorting to some kind of regulatory benchmarking tool. Reference benchmarking would be the most immediate substitute to frontier benchmarking. (Turvey, 2006) states that methods relying on engineering knowledge seem superior to other approaches, mainly due to the limitation in reflecting the influence of environmental variables on distribution costs. Moreover, Turvey argues that most (black-box) benchmarking studies use the amount of energy distributed as an output when this is merely a throughput. According to Turvey, the real output of a DSO would be the capacity provided to the network users, which can only be adequately measured through reference benchmarking methods. (Turvey, 2006) discusses two different approaches, which he names “scorched earth” and “scorched node”. These basically correspond to norm models and New Zealand’s ODV approach respectively.

However, criticism of the engineering benchmarking approaches can also be found in the literature. (Jamasb and Pollit, 2008) analyse the application of the NPAM in Sweden and conclude that norm models should not be used as the primary benchmarking tool to regulate electricity distribution. The use of RNMs according to (Jamasb and Pollitt, 2008) should be limited to the assessment of large new investments, design and overseeing of access charges, in situations where the number of comparators is limited or countries where the information available to the regulator is limited or of poor quality. A significant share of this criticism is related to the particular Swedish regulatory design based on an ex-post regulation with annual reviews that may create regulatory uncertainty thus hindering long-term efficiency. Nonetheless, these authors point out to some drawbacks of the NPAM itself.

- Firstly, NPAM requires several cost functions that only depend on the load density whereas actual costs can depend on several other environmental variables. It is true that NPAM models environmental variables in a simplified way. However, it is arguable that frontier benchmarking may capture their effect in a better way by performing second stage regressions or adding additional variables to the models. Moreover, this limitation is specific of the NPAM. RNMs can indeed model in much more detail environmental variables, as shown in the description of the Spanish model of chapter 4. In fact, this is probably the main advantage of RNMs over frontier benchmarking.
- Probably, the most relevant issue pointed out by (Jamasb and Pollit, 2008) is that NPAM, and RNMs in general, cannot reflect all inner complexities of real firms and the potential tradeoffs faced by real DSOs, as they may choose different mix of inputs to provide the same service to their network users. The reason for this lies in the fact that the reference network is built deterministically according to certain predefined rules. Moreover, since the results of RNMs is an optimal grid design that does not consider the past conditions under which actual grids were developed, an inappropriate application of RNMs could penalise DSOs for issues outside their control. This is particularly true if a short-term approach to regulation is implemented, as in the case of Sweden where annual reviews were carried out. Despite the fact that these arguments are quite true, several observations could be made in this regard.

On the one hand, the purpose of RNMs should be to provide an estimation of efficient network costs for each DSO taking into account the particularities of its distribution area. However, similarly to the fact that inefficiency results obtained with frontier benchmark should not be directly translated into X factors, these results should never be seen as mandatory design rules or final revenue allowances. Notwithstanding, since the rules implicit to the RNM being used are common to all DSOs, this information can be very helpful for regulators willing to overcome asymmetries of information. In any case, it seems inevitable that regulators make discretionary decisions when determining the final revenue allowances.

On the other hand, the assumptions implicit in any frontier benchmarking model can be much more stringent than those needed in RNMs. For instance, in non-parametric frontier benchmarking each firm is compared against a hypothetic linear combination of other firms which may not be attainable by the real firm, depending on whether the implicit assumptions regarding convexity, free disposability or returns to scale hold in reality. Similarly, parametric frontier benchmarking assumes that the form of the cost/production function is known and each firm is compared against another which will not have the same combination of inputs and outputs. What is more, the selection of variables and the form of the cost/production function is frequently influenced to a certain extent by convenience and data availability.

- An additional source of criticism raised by (Jamasb and Pollit, 2008) is that periodical updates of the inputs to norm models present a limited capability to reflect the innovation achieved by DSOs since this information will be at best based on recent past technologies. The authors argue that an ex-ante estimation of the TFP growth to measure the frontier shift may indeed reflect this process. In this case, this is partly motivated by the consequences of ex-post regulation rather than the intrinsic properties of RNMs. Although it is true that the update of input data to norm models will be mainly based on past technologies, it seems inevitable that the TFP estimates also suffer from this shortcoming. In fact, engineering knowledge could be used in order to incorporate future technology improvements into the RNMs in order to promote innovation from DSOs. However, this does not seem possible when using the TFP growth approach.
- Furthermore, (Jamasb and Pollit, 2008) state that replacement costs will be the only asset valuation methodology that can be used by norm models without incurring in significant added costs, whereas frontier benchmarking allows using either replacement costs or book values as done in Norway. However, this depends to a certain extent on how the RNMs are applied by regulators. Two main issues are relevant in this regard. On the one hand, either greenfield or expansion-planning RNMs can be used. The regulator may implement the former alternative to reassess the asset base or only to estimate the future investments needs of each DSO. The latter option could be applied to determine a yearly update of the allowed revenues, as done in Spain (Cossent et al., 2011b), or to determine future investment needs, for example as a substitute of OFGEM's reinforcement model described in chapter 4, similarly to the proposal made for Spain in chapter 5. On the other hand, the investment cost of assets used as input to the RNMs can be either defined, for each type of asset, according to book values, replacement costs or even benchmarked across DSOs to promote further efficiency gains.
- An additional weakness of the former Swedish regulation is that the information contained in the database used to value network assets is provided voluntarily by

DSOs, which may provide these firms with perverse incentives. However, the incentive for DSOs to game the regulator is present in any regulatory accounting system, including when frontier benchmarking is applied as discussed in (Jamasb et al., 2003; Jamasb et al., 2004). In order to minimise these problems, precise definitions of the information required, clear obligations and auditing mechanisms should be established by regulators (Jamasb et al., 2003; Jamasb et al., 2004).

- Moreover, (Jamasb and Pollit, 2008) discuss about the extensive information burden and resources devoted to developing and maintaining the NPAM. These requirements will increase with the number of firms to be regulated. They argue that the benefits from the more detailed information of the use of NPAM may be outweighed by the increased resources needed. Finally, they state that RNMs could be used when adequate relevant technical data from the firms may not be available.

  The large information requirement of any RNM, and particularly of expansion-planning RNMs, is one of the main practical drawbacks of applying RNMs in regulation. Gathering these data requires significant effort both from DSOs and regulators. Nonetheless, it is hard to prove that this is not worth the deeper knowledge about the regulated firms gained thanks to the RNMs. The issue of the quality of technical data of DSOs is partly true as greenfield RNMs can be used when detailed information about the network or part of it is not available. For example, a greenfield RNM is used in Spain for LV grids (using actual MV/LV transformers as input) because DSOs do not have the complete data about the existing LV network. However, this would not be possible when running expansion-planning RNMs. In any case, very detailed information about consumers and network assets would be needed.

- Another aspect pointed out by (Jamasb and Pollit, 2008) that is inherent to any RNM is the high complexity and detailed modelling may reduce transparency and deter third-party participation. An advantage of frontier benchmarking over RNMs is that the results are more easily reproduced by independent stakeholders. However, it seems arguable that other stakeholders, presumably except for some academics or consultants, may actually do this in practice. It is equally arguable that frontier benchmarking models could be more easily understood than RNMs by, for example, consumers' representatives. In fact, frontier benchmarking methods are becoming more and more complex, e.g. panel data models in SFA or the different DEA models described in chapter 4, to overcome their limitations. Therefore, other aspects such as the existence of an independent regulator provided with adequate resources and the publication of regulatory decisions in a clear and transparent way may be much more relevant in this regard, than the selection of the benchmarking method itself.

- Last but not least, a subtle difference between both approaches, which provides certain superiority to frontier benchmarking, is that RNMs develop a benchmark for each firm individually. This may contradict one of the objectives of incentive regulation should be to create and promote competition in sectors where this is not likely to occur naturally. Moreover, this could lead to a vision of regulation as a cut-and-thrust between each single firm and the regulator instead of a zero sum game (Jamasb and Pollit, 2008). Nonetheless, this can be mitigated by means of an appropriate regulatory design. For instance, the distance of each DSO to its reference network could be measured and compared across DSOs, following the concept of relative reference network (Paulun et al., 2008), or by benchmarking input cost data.

(Haney and Pollitt, 2009) perform a survey across regulators in 40 countries and construct a best practice index for regulatory benchmarking. In (Haney and Pollitt, 2011), the same authors explore the factors that drive the adoption of best practice in regulatory benchmarking according to the previously constructed index. One of the criteria used to compute the best practice index is the use of advanced benchmarking tools. Nonetheless, the authors avoid discussing the superiority of any benchmarking method over others by assigning the same weight to any frontier benchmarking method and what they call process/activity benchmarking. This latter category is defined as any bottom-up methodology aimed at calculating optimal costs and efficiency. This definition is very similar to that of reference benchmarking. Hence, it seems the authors are placing both frontier and reference benchmarking at the same level. Unfortunately, the answers to the survey did not contain detailed information these models. Thus, the previous publications do not discuss reference models in detail.

As previously mentioned, (Agrell and Bogetoft, 2003) perform a review of existing benchmarking approaches for electricity distribution. Within the different approaches, they define a category named engineering, which basically refers to RNMs. The authors state that the adoption of these models is driven by the insufficient number of firms within the country or the low quality of data. In order to compare the different approaches, (Agrell and Bogetoft, 2003) illustrate the frontiers obtained with each benchmarking method in a qualitative way as shown in Figure 6-2. It can be seen that engineering models are represented as a convex frontier which is not attained by any of the regulated firms.

It is true that the results of RNMs are, in theory, optimised and therefore beyond the actual frontier which is computed by frontier benchmarking methods. In addition to the fact that RNMs and frontier benchmarking use the same inputs and outputs, the previous figure is misleading in two senses. Firstly, RNMs provide a separate benchmark for each DSO. Thus, such a frontier would not be obtained by the RNMs but a set of points, one for each firm. Moreover, the calculations carried out by RNMs are full of non-convexities and discontinuities. Therefore, even if such a frontier could be obtained, this could not be done by merely connecting the dots forming a convex hull. It would probably present a very different shape than the one shown in Figure 6-2.

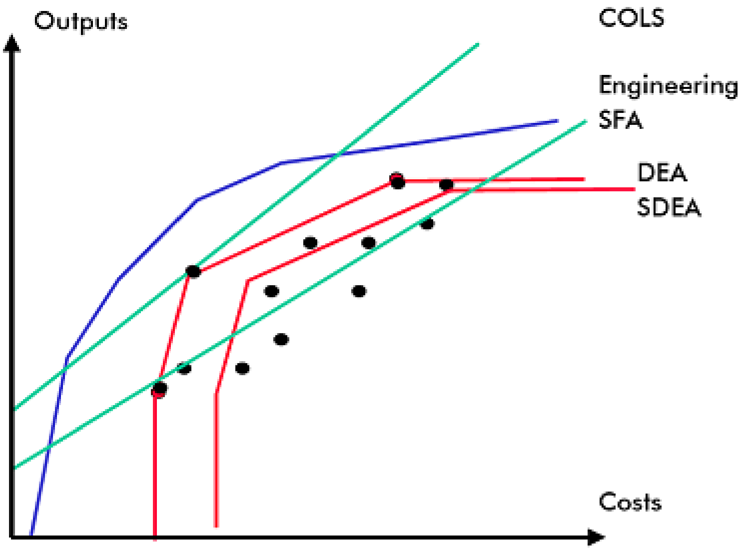

Figure 6-2: Efficiency frontiers in different benchmarking methods (Agrell and Bogetoft, 2003)

6.3.2 Contribution to the discussion

The previous review has shown that there is not a definite conclusion as to the most appropriate benchmarking approach. Most surveys reveal that frontier benchmarking methods, especially DEA, are the most common benchmarking approach (Jamasb and Pollitt, 2001; Agrell and Bogetoft, 2003). Nonetheless, the difficulties in benchmarking CAPEX has led to some regulators well known for the use of frontier benchmarking, such as OFGEM, to resort to bottom-up analyses as shown in the example in chapter 4. This may not be an isolated case given the fact that many regulators combine economists and engineers as consultants in the price review processes (Haney and Pollitt, 2009). What is more, their survey also reveals that the most common benchmarking method used both in the gas and electricity sectors was what they called process/activity benchmarking, whose definition broadly matches with the reference benchmarking term used herein. All this suggests that engineering methods are widely used as well but tend to be less publicised.

A thorough discussion about the overall merits of each approach, and not a particular application of one of them, seems to be missing in the literature. Hence, the following discussion aims at contributing towards the common understanding and closer cooperation between the regulatory approaches of economists and engineers as suggested by (Grifell-Tatjé and Kerstens, 2008). Following the methodology of (Jamasb and Pollit, 2008), this comparison has been structured according to a set of criteria. Nonetheless, a distinct set of criteria is used herein.

On the one hand, the issues that were deemed to be more related to the overall regulatory design and activities of the regulator rather than the choice of benchmarking tool have been removed. It is important to differentiate between the tool used and how it is used. For example, the possibility to attract new investments and promote long-term innovation and the transparency and certainty in regulatory decisions are largely influenced by a myriad of factors beyond the benchmarking approach used. On the other hand, additional criteria have been added to assess the suitability of each benchmarking approach given the upcoming changes and challenges in electricity distribution networks. Additionally, several authors have applied both frontier benchmarking and RNMs for purposes different than regulatory benchmarking, although many of them not unrelated to regulation. These will be briefly described so as to illustrate the possibilities offered by each approach.

i) Efficient comparators

Including environmental variables (factors that can affect costs but are uncontrollable by DSOs) in benchmarking is extremely relevant as they may be a major source of heterogeneity across firms. The main advantage of RNMs over frontier benchmarking is that they implicitly take into account the effect of the most relevant environmental variables on distribution network costs and how they affect differently to each DSO. These variables comprise the density of loads, the existence of different types of distribution areas (urban, rural), orography and forbidden areas, load factors, etc. Nonetheless, it is true that some other variables such as type of soil, wind speed, distance to coast, etc. cannot be directly considered despite the fact that they may affect distribution costs. However, the costs of network components used as input data for these areas could be modified accordingly.

In frontier benchmarking methods, this heterogeneity may be wrongly regarded as inefficiencies (Shuttleworth, 2005). In spite of increasing the size of the sample or performing international benchmarking, frontier benchmarking models cannot develop comparators that consider aspects that are exclusive of a specific distribution area or a reduced subset of firms. Therefore, DSOs supplying an area with a very scattered population or with large penetration levels of DG can be jeopardised. Notwithstanding, the use of SFA models with panel data can mitigate this problem. Moreover, non-convex frontiers (FDH models) can reduce the gap between black-box and reference benchmarking (Grifell-Tatjé and Kerstens, 2008).

(Jamasb and Pollitt, 2008) state that RNMs can penalise firms that do not follow strictly the planning rules used to develop the reference networks. However, it is unclear why RNMs would penalise firms that make trade-offs between different types of costs, as long as these are made efficiently. As mentioned previously, if the norm models are appropriately developed, they should provide a level of efficient costs for each distribution area. Actual DSOs may deviate from the design of the reference network, although if this is done efficiently the total network costs should not deviate excessively. Moreover, some of the existing tradeoffs can be taken into account when building the reference networks. For example, the Spanish RNMs use the cost of energy losses together with the maximum loading of each network component when determining its size. Thus, the models will optimise network components in order to minimise the investment cost plus the cost of energy losses. Similar tradeoffs would be considered regarding continuity of supply.

Reference networks, more specifically greenfield reference networks, neglect the historical evolution of actual networks. Consequently, the results should not be directly used as revenue allowances. The regulator may need to ask firms to explain the existing deviations. This drawback can be mitigated by using expansion-planning RNMs. (Jamasb and Pollitt, 2008) state that frontier benchmarking reflects this more adequately because actual networks are used to create the benchmarks. When saying this, the authors are assuming that all the networks have faced similar historical evolutions. Being this the case, all firms would show the same differences as compared to reference networks as it would be possible to correct for these deviations. However, the past situations faced by actual networks may differ across areas and/or DSOs. These differences may enlarge when resorting to international comparisons. Hence, both RNMs and frontier benchmarking may consider deviations caused by the historical evolution of the network as inefficiencies. Nonetheless, frontier benchmarking would only fail to incorporate the divergences across DSOs, whereas norm models may not adequately reflect any effect of historical evolution.

Lastly, it is important to remark that RNMs can only consider network related costs whereas frontier benchmarking can be applied to any context. Therefore, despite the fact that network related costs account for a major share of distribution budgets, RNMs would require additional tools to assess the remaining cost elements. These several other issues comprise corporate costs, marketing, rental costs, R&D expenditures, etc.

ii) Quality of service

RNMs can include the existing tradeoffs between costs and quality of service in different manners. The Swedish NPAM minimised the total social costs of interruptions, calculated as the sum of quality-driven investments and the cost of interruptions for consumers. On the other hand, the Spanish RNMs reinforce the reference network until the constraints imposed regarding continuity of supply are satisfied. The WTP in the Swedish model or the limits for continuity indices in the Spanish model depended on factors such as the type of consumers or the load density.

On the other hand, frontier benchmarking studies do not generally consider the quality of service provided by DSOs. Frontier benchmarking can capture the quality dimension at the cost of adding additional variables, which presents well known complexities both in parametric and non-parametric approaches. These problems may be worsened due to the fact that quality of service is greatly correlated with environmental variables such as load density or degree of undergrounding, which may be needed to account for heterogeneity. Otherwise, performing frontier benchmarking incorporating quality-related variables may benefit DSOs supplying areas where quality is easier to provide such as urban areas; especially in non-parametric methods as such a firm could appear as fully efficient due to the quality dimension. Moreover, several continuity indices are used in regulation in order to account for the frequency and the duration of interruptions. These indices are largely correlated among them, which may create problems for parametric analyses.

(Giannakis et al. 2005) and (Growitsch et al., 2009) present the few frontier benchmarking studies that consider quality of service in distribution networks, using DEA and SFA respectively. The results show how including quality of service in benchmarking can significantly change the efficiency results. (Estache et al., 2004) argue that gross national product may account for quality requirements in international comparisons. They argue that this may not be the most suitable variable for this, but data availability and homogeneity across countries make it difficult to use directly quality indices.

iii) Robustness of benchmarking results

The high sensitivity of results of frontier benchmarking to the selection of the method and the model specification has been reported in several studies (Jamasb and Pollitt, 2003; Estache et al., 2004; Farsi et al., 2007). The different solutions proposed to overcome this deficiency do not seem to adequately solve this problem. These solutions comprise using geometric averages of efficiency results (Coelli and Perelman, 1999), performing ex-post correlation tests (Estache et al., 2004; Agrell and Bogetoft, 2007) or measuring the significance of efficiency scores through the ratio of the variance of the inefficiency over the sum of the variances of noise and inefficiencies (Jamasb and Pollitt, 2003).

In principle, RNMs are more robust since they do not depend that much on model specification and data availability. However, developing these models has proven to be challenging in reality. For instance the studies performed over the NPAM in (Wallnerstrom and Bertling, 2008) show that relatively small variation in the input data regarding the location of substations and consumption profiles cause large changes in the results. Nonetheless, the authors point out that these problems are presumably caused by some of the planning rules followed by the model. Such systematic analyses have not been published for the Spanish RNM, although no major problems have been reported in this regard. Nevertheless, different analyses where the consumption levels or the inclusion of new consumption points or DG units have been presented in (Cossent et al., 2010; Cossent et al., 2011c; Pieltain Fernandez et al., 2011). These publications do not report any problems of robustness and the results do not show erratic variations.

iv) Number of firms and size of distribution areas

It is widely acknowledged that the size of the sample in frontier benchmarking methods is an essential parameter. A low sample size limits the number of variables that can be included in the specification of non-parametric models, or prejudice the significance of the results of parametric methods. Therefore, frontier benchmarking seems more suited for countries with a large number of firms. The sample size can be further enlarged by using panel data or international benchmarking, although several difficulties have to be faced in these cases.

The main limitation when using RNMs does not lie in the number of firms, but on the size of the distribution areas, in terms of square meters and number of network users. The more extensive the distribution area, the more resources will be needed to gather the input data and compute the results. Thus, from the perspective of strictly running the models, there is not a great difference in applying RNMs to 1 DSO supplying 2 million consumers and doing it to 4 DSOs supplying 0.5 million each. Notwithstanding, other regulatory processes such as the implementation of a new regulatory accounting system may indeed depend on the number of firms.

v) Regulatory burden

In general, the more complex a benchmarking tool is, the deeper information it can provide about the behaviour of regulated firms. However, an additional and important issue to consider is that actual regulators have limited human, information and financial resources (Joskow, 2010). Because of these, it is desirable to reduce the burden placed on regulators in price reviews.

In this regard, frontier benchmarking, and especially non-parametric methods, has a clear advantage over norm models since the resources required to develop and maintain the benchmarking models are much lower. Since these are generally simpler models widely applied in many sectors, several software developments are commercially available. On the contrary, RNMs are generally tailor-made models developed by external consultants/researchers, as in the cases of Sweden, Spain and Chile. Moreover, the information required to compute the efficiency estimates are reduced. Therefore, the time and resources needed to define, implement and fill in the regulatory accounting system are increased considerably. Finally, as described in section 6.2, important computational resources may be needed. The computational needs of RNMs require dedicated computers and limit the analyses that can be carried out with the limited resources of the regulator.

Nonetheless, as revealed in the survey in (Haney and Pollitt, 2009) regulators generally engage external consultants from different fields, regardless of the benchmarking approach followed. In many cases, regulators applying frontier benchmarking also hired engineers to participate in the price review processes. This is presumably needed to contrast the firms' statements about those issues that require some technical knowledge. RNMs can allow regulators to reduce the reliance on external consultants in these cases or provide additional evidence to support their decisions. Furthermore, once the norm models and the information systems have been implemented, the burden is certainly reduced. Overall, it seems clear that RNMs imply a considerable regulatory burden. However, it remains to be determined whether the extra information they provide is worth it, including the additional application of RNMs that will be described below. This probably requires a case by case analysis and may depend on subjective criteria.

vi) Readiness to contrast benchmarking results

Third-party participation and negotiation in the regulatory decisions has been advocated to reflect the interest of consumers and reduce the complexity of price reviews (Littlechild, 2011). The use of negotiated settlements and customer participation is limited by practical considerations in the energy (and water sector), albeit some of these mechanisms may be adopted in the future (Littlechild, 2011). The transparency and simplicity of the regulatory processes are essential to facilitate stakeholders' participation.

In this sense, a desirable feature of benchmarking results is to be easily replicated and validated.

RNMs are much more difficult to validate and to apply in independent studies mainly due to the difficulties related to the model replicability and data availability. Despite the fact that the RNMs could be made available to be run by external agents, the data about the location and consumption of customers are generally confidential. On the other hand, whilst it is true that the results of frontier benchmarking models can be more easily reproduced by third-parties interested in participating in the regulatory process, this is not generally performed as most stakeholders know as much about frontier benchmarking as about RNMs. Additionally, the concept of network planning inherent to RNMs can be more readily understood by stakeholders and more easily accepted by DSOs.

vii) Diffusion of best practices

Benchmarking should encourage regulated firms to adopt best practices observed in the sector. This could be done by inducing some aspects of competition among DSOs within the benchmarking approach. As mentioned before, RNMs establish separate benchmarks for each firm. This does not induce competition among firms and may be seen as a DSO versus model/regulator process. On the contrary, frontier benchmarking is based on performance comparisons across actual firms. Therefore, they would be better prepared to diffuse best practices across DSOs. Nonetheless, this drawback of RNMs can be partly overcome with an appropriate implementation. The use of relative reference networks or benchmarking certain input data, such as investment and maintenance costs or repair times, can be carried out for these purposes.

viii) Impact of DER

In chapter 2, it was shown that the large-scale connection of DG and other DER have important consequences for the economic regulation of DSOs. These include the impact of DER on distribution network costs. This effect can depend on many different factors. RNMs have proved to be a suitable tool to analyse these effects as shown in existing studies (Cossent et al., 2010; Cossent et al., 2011c; Pieltain Fernandez et al., 2011).

Frontier benchmarking can account for these effects by including additional variables in the models. DER, either their number or some energy-based parameter, could be considered as output or environmental variables. Alternatively, second-stage regressions to analyse the sensitivity of efficiency results to DER-related variables could be performed. (Agrell and Bogetoft, 2007) are one of the few examples where DG is considered in frontier benchmarking analyses. The results show that DG is significant in order to determine the efficiency of DSOs and that its effect can be different depending on the voltage level (Agrell and Bogetoft, 2007).

The previous study was conducted with data from 328 DSOs. However, such a large sample is not likely to be available in many countries. Therefore, statistically significant results may be difficult to obtain adding such variables in these countries. This is worsened by the fact that DG is generally connected more intensively in areas with more abundant resources (wind, solar technologies) or certain types of consumers (industrial CHP), which adds further heterogeneity problems. Moreover, DG can affect differently to each DSO depending on the type of consumers present in the area, load density, size of generators, generation technologies present, etc. Parametric models with panel data can be implemented to overcome this limitation. However, previous experience has shown that this large-scale connection of DG can take place very rapidly or stagnate suddenly depending on regulatory changes; see for example the case of PV in Spain before RD

1028/2008 was passed described in (Cossent et al., 2011a). Therefore, panel data may not adequately capture these effects. (Cossent et al., 2011a)

Additionally, the amount of energy distributed annually and the number of consumption points are frequently used as the most important output variables in frontier benchmarking analyses (Jamasb and Pollitt, 2001). The presence of DER, especially at large-scale, may render these variables questionable. On the one hand, DG[41] or demand response may reduce the amount of energy distributed. However, connecting DG and implementing demand response programmes cause additional costs. Therefore, if the benchmarking models remain unchanged, a reduction in the outputs would paradoxically require an increase in the inputs. This would penalise those DSOs with the higher shares of DER. In fact, (Agrell and Bogetoft, 2007) use peak load at different voltage levels as outputs instead of the energy distributed. On the other hand, it is unclear how to compute the number of consumers (frequently measured as the number of meters) in a situation where DG can be connected under net-metering schemes, different types of charging points and metering schemes can be available to EVs (Gómez et al., 2011), and demand response modifies to a larger extent the consumption profile of different consumers.

All these issues can be easily taken into account within RNMs, including the particular situation of each DSO. This requires carefully defining the input data concerning the behaviour of the consumption/generation profiles of the different network users. Nonetheless, this can be achieved with relatively simple assumptions as done in (Cossent et al., 2010; Cossent et al., 2011c; Pieltain Fernandez et al., 2011).

ix) Capture the effects of technology changes and innovation

The adoption of smarter distribution grids will bring about significant technology changes. This transition will be characterised by a more intensive use of ICT and the installation of new devices, especially at MV and LV. The technology change together with the connection of DER will cause profound changes in the way distribution networks are currently designed and operated. Under this paradigm, regulatory frameworks should aim at encouraging DSOs to innovate. Thus, regulatory benchmarking should adopt a forward looking strategy when determining the efficient costs in the near future. Otherwise, the technology risks (technical obsolescence, uncertainty over reliability of new equipment, short lives of new assets, long-term return of investments, etc.) would deter DSOs to trust new solutions for fear of being penalised by regulation.

(Jamasb and Pollitt, 2008) state that estimations of the TFP growth capture the innovation and technical progress. It is true that TFP growth allows regulators to quantify the effects of innovation and technology change. However, TFP and frontier benchmarking is necessarily based on past information, thus being intrinsically backward looking. This approach to regulation can create problems when high uncertainties about the future exist. An example that can illustrate these problems is the current situation of the European ETS currently under revision. The price of CO2 has dropped dramatically basically because that emission permits were issued on the basis of historical emissions. However, the advent of the economic crisis has caused a sudden reduction in the industrial activity thus creating a large surplus of emission allowances which are now worth virtually nothing.

[41] DG may reduce the amount of energy distributed by itself if it is measured at the frontier substations. Nonetheless, this would not happen when it is measured at the customers' meters. Notwithstanding, even in this case, under net-metering schemes relying on a single meter DG reduces the amount of energy delivered without being possible to measure this reduction independently.

Furthermore, TFP estimations require a time span of several years to adequately measure the frontier shift. For example, (Jamasb et al., 2008) analyse the productivity of US gas transmission companies with data from the period 1996-2004 (9 years), (Forsund and Kittelsen, 1998) do the same for Norwegian DSOs in the period 1983-1989 (7 years) and (Tovar et al., 2011) perform a similar analysis for Brazilian distribution utilities in the period 1998-2005 (8 years). Therefore, it seems arguable that TFP growth is appropriate to reflect and promote innovation when technology is rapidly changing (periods shorter than 5 years).

(Jamasb and Pollitt, 2008) argue that frequent updates of the NPAM input data are not a substitute of the innovation process of real firms. Nonetheless, it seems that this criticism is largely motivated by the ex-post regulatory approach implemented in Sweden. Note that a similar criticism could be made about the ex-post annual updates performed in Spain by using an expansion-planning RNM (Cossent et al., 2011b). However, contrary to frontier benchmarking, RNMs can be used both in backward and forward looking approaches depending on how the input data are defined. On the one hand, this would require resorting to engineering knowledge in order to incorporate the effect of new technologies and innovation on costs, service restoration times after an interruption, etc. Moreover, using different forecasts of new consumer connections, load growth, demand response programmes or DG connections can allow regulators to quantify the future investment needs under different technology assumptions (Cossent et al., 2010; Pieltain Fernandez et al., 2011).

x) Additional applications

All throughout this section, the focus has been placed on regulatory benchmarking. Nevertheless, both frontier benchmarking methods and RNMs can be used for some other purposes. Despite these issues are not directly related to this discussion, it is deemed relevant to mention some of these applications as they can be used in regulation.

Frontier benchmarking essentially obtains the cost/production function of a hypothetic efficient firm from the observation of past performance. The additional uses of frontier benchmarking are based on the analysis of the properties of this function. This has allowed several authors to evaluate the influence of certain factors over distribution costs and efficiency such as geographical location (Hattori, 2002; Hattori et al., 2005), recent history (Hirschhausen et al., 2006; Cullmann and von Hirschhausen, 2008), quality of service (Giannakis et al., 2005; Growitsch et al., 2009), weather (Yu et al., 2009) or who holds the ownership of the distribution companies (Hjalmarsson and Veiderpass, 1992). Moreover, some other authors have tried to determine whether mergers of distribution companies would lead to higher efficiency owing to economies of scale (Filippini et al., 2004; Tovar et al., 2011) or to quantify efficiency gains from a more intensive use of network assets (Kopsakangas-Savolainen and Svento, 2008).

RNMs calculate bottom-up the cost of building and operating a reference network with a detailed geographical representation of network assets and users. Therefore, they can be used to perform quantitative evaluations of certain issues that can affect differently to each type of distribution area. There are already several studies with immediate regulatory application such as the computation of incentives for DSOs to reduce energy losses (CNE, 2010), computing the so-called economies of scale factors (marginal increase of distribution cost with the energy distributed) in the presence of DG (Mateo et al., 2011) or assessing the reference values in quality of service incentive schemes (Fernandes et al., 2012). Moreover, RNMs allow quantifying the impact of DER on energy losses (González-Sotres et al., 2011) or distribution network costs (Cossent et al., 2010; Cossent et al., 2011c; Pieltain Fernandez et al., 2011) considering all the heterogeneity across distribution areas.

6.3.3 Lessons learnt and application to actual situations

The previous review has identified the major pros and cons of using frontier benchmarking and RNMs for regulatory benchmarking when compared among them. The previous discussions lead to the conclusion that no approach is superior in all dimensions to the other, and that it is difficult to perform quantitative comparisons due to their large differences. Nonetheless, in order to summarise the results of our review, Table 6-2 shows a qualitative comparison comprising the main performance criteria considered.

		RNMs	Frontier benchmarking
Efficient comparators	Environmental variables	green green green	amber amber
	Heterogeneity	green green green	red
	Cost trade-offs	amber amber	amber amber
	Historic evolution	red	amber amber
	TOTEX benchmarking	amber amber	green green green
Quality of service		green green green	red
Robustness of results		amber amber	red
Number of firms		green green green	red
Size of the distribution area		amber amber	green green green
Regulatory burden		red	green green green
Contrast results		red	amber amber
Diffusion of best practice		amber amber	green green green
Impact of DER		green green green	amber amber
Technology change		green green green	red

Table 6-2: Qualitative comparison of frontier benchmarking and RNMs. For each criterion and benchmarking approach: "green" means good performance, "amber" may have some difficulties and "red" poor performance.

The main advantage of frontier benchmarking models is that they require limited resources, thus minimizing the burden placed on regulators. At the same time, this simplifies price reviews and facilitates external contrasting of the results. Moreover, frontier benchmarking models can easily account for all the types of costs incurred by DSOs, including those unrelated to the network itself. Lastly, frontier benchmarking models are not limited by the size of the distribution areas and their results adequately reflect the true evolution of the grids. However, the main shortcoming of this approach is that frontier benchmarking is very sensible to the model specification and the number of firms/observations. Additionally, capturing the effects of environmental variables, quality of service and the heterogeneity among firms may be difficult. These problems are bound to exacerbate as a result of the transition towards smarter distribution grids and the large-scale connection of DER due to the intrinsic backward looking orientation of these methods.

On the contrary, the heavy burden placed on regulators is the RNMs' main drawback. The complexity of the models may additionally hamper third-party participation in regulatory processes. Furthermore, some corrections may be necessary to account for factors outside the control of DSOs that affected the past evolution of the network. Additionally, RNMs are specifically focused on the evaluation of network investments, which at the same time allows estimating the efficient network related OPEX. However, other distribution costs cannot be captured by these models in any case. On the other hand, precisely due to this characteristic, RNMs (or some form of reference benchmarking) could be essential in a context where significant network investments are expected, for instance, due to a rapid load growth or the connection of DG. Furthermore, the complexity of RNMs presents the advantage that the effects of environmental variables and quality of service as well as the heterogeneity across DSOs can be directly taken into account when determining the efficiently incurred costs. This particular feature of RNMs will presumably become especially relevant to account for the impact of DER and the rapid technology changes ahead.

The strengths and weaknesses previously identified show that frontier benchmarking and RNMs are somewhat complementary. However, it remains to be analysed in detail whether both approaches can be used jointly and how this can be done in practice. Further research and experience is needed to find potential joint applications of both approaches to regulatory benchmarking. Nonetheless, there seems to be significant scope for this cooperation among regulatory viewpoints. Furthermore, the final choice of tools is greatly influenced by a wide range of issues, many of them specific to the context of each country such as the number of firms within the country, the penetration of DG, the smart grids developing stage, the background and experience of the regulator, experiences gathered in neighbouring countries, etc. The situation and practical experience in the application of regulatory benchmarking in different countries will be discussed hereinafter to illustrate these issues.

Spain

The Spanish distribution sector was described in chapter 5. It was shown that the five major DSOs supply the vast majority of end-consumers. These firms, together with two other DSOs which supply more than 100.000 consumers, are subject to a revenue cap regulation through the use of RNMs. This context complies with many of the characteristics that make reference methods suitable. More specifically, the number of DSOs is very low and these supply very large areas which present notably different characteristics in terms of size of the area, dispersion of consumers, orography, etc. Consequently, capturing the heterogeneity and environmental variables within the benchmarking model is very relevant. Moreover, the promotion of RES and CHP has resulted in a significant penetration level of DG (Cossent et al., 2011a).

Notwithstanding, the implementation of RNMs has been a progressive process since 1997. In addition, it was facilitated by the fact that the first norm model applied in Spain (BULNES model) was developed and proposed by a distribution company at the time of liberalization (Blázquez-Gómez and Grifell-Tatjé, 2011). Alternatively, the regulator could have opted for using frontier benchmarking.

In spite of the reduced number of firms, this could be done by considering as DMUs pairs of company-province, as already done in previous analyses by the regulator when computing the economies of scale factors described in chapter 4 (CNE, 2007). Therein, the CNE identified 76 pairs DSO-province sorted into 6 clusters according to a density factor defined as the ratio of number of consumers over peak demand. Nevertheless, two of these clusters, comprising six pairs in total, were identified as very small regions that ought not to be considered. The remaining 70 DMUs could facilitate the use of frontier benchmarking. The main problems would then consist in ensuring that the frontier models are appropriately specified to reflect the heterogeneity across regions and then translating the benchmarking results disaggregated by provinces into efficiency scores for each DSO or how to apply these results to evaluate the investment plans submitted by DSOs.

On the other hand, the remaining more than 300 small DSOs that operate in Spain have been traditionally subject to a separate regulatory regime close to a light-handed regulation. Nonetheless, there are plans to progressively integrate them into the general regulatory framework. Therefore, cost benchmarking for these DSOs could become more relevant in the future. However, these DSOs are usually connected downstream of the network belonging to one of the major DSOs and only operate very small areas at the lower voltage levels. Frontier benchmarking clearly seems more suitable to evaluate the efficiency of these firms. Their number is sufficiently to build representative frontier models and may even hamper the use of RNMs for each one of them individually. In addition, due to their differential features, they can be hardly compared with the DSOs previously discussed[42].

Portugal

Portugal is another interesting case study given its particular features. The electricity distribution activity is carried out by a single DSO[43]. This alone would suggest that the regulator would be forced to use some form of reference benchmarking. However, as described in (ERSE, 2008), different DEA and SFA models were used by ERSE to set efficiency objectives on EDP Distribução for the period 2009-2011. In order to do this, EDP's network was divided into 14 distribution areas. Data from 2003 to 2006 were used, carrying out efficiency analyses for each year independently.

Up to 15 different models were developed using different techniques and model specifications. The techniques comprise DEA models both under CRS and VRS assumptions, and SFA models using different types of cost functions (linear, log-log, translog) and assumptions about the statistical distribution of the error term. A single input, i.e. controllable costs, was considered in all cases, whereas three sets of output variables were considered: i) energy distributed and network length, ii) energy distributed, network length and share of LV network, and iii) energy distributed, number of customers, network length, share of LV network, share of underground network, customer density and the TIEPI reliability index.

From the aforementioned 15 models, up to 9 were discarded by ERSE due to different problems. All the parametric models whose specification included the full set of output variables (translog cost function) were rejected because, besides presenting some multicollinearity problems, the efficiency results did not show adequate statistical significance. Other parametric models using the other two sets of variables (log-log cost functions) were cast aside due to similar problems. In the end, the only SFA models left

[42] A consequence of benchmarking all the DSOs within the same model in Spain could rapidly lead to mergers/acquisitions of the smaller firms by the major ones. For the time being, the regulator has not expressed the desire to encourage this.

[43] Only continental Portugal is being considered.

were those assuming linear cost functions and incorporating a reduced number of output variables. This suggests that one of the main causes for the previous problems lies in the limited number of observations, since linear functions require estimating a lower number of parameters and reducing the number of variables mitigates potential multicollinearity problems. Nonetheless, the parametric models finally selected could be missing out many variables that could be important to explain cost differences in real life.

Furthermore, after measuring the consistency of efficiency results among the different models through a correlation matrix and a comparison of the efficiency rankings provided by each model. As a result, three DEA models were excluded as well because they were deemed inconsistent with the rest of models. Two of these DEA models incorporated the full set of output variables, whereas the remaining one was a DEA with VRS and three outputs. These models were also those showing the highest efficiency ratings. Once again the reduced number of DMUs seems to be the major limitation. Two of these models include a total of 8 variables, whereas the number of DMUs is just 14. Therefore, the rule set in (Cooper et al., 2000) stating that the number of DMUs must be higher than three times the sum of all variables is clearly violated. Moreover, the one DEA model left does not violate this rule (four variables and 14 DMUs), although it is close to doing it. Additionally, this is a VRS model, thus limiting the number of peers for each firm.

The analysis described above shows that the efficiency analyses carried out by ERSE to set distribution revenues for the period 2009-2011 presents important shortcomings, mostly driven by the reduced number of DMUs considered. An immediate solution could be to divide EDP's network into a greater number of DMUs, e.g. into provinces as suggested above for Spain. However, continental Portugal is divided into just 18 districts. Moreover, given the reduced size and population of Portugal as compared to other countries such as Spain or the UK and its orography, heterogeneity problems may arise. Hence, alternative solutions could consist in the use of panel data models instead of merely comparing annual benchmarking results. Lastly, in spite of being a more profound change, the regulator could consider implementing some form of reference benchmarking given that it could match the characteristics of the Portuguese distribution sector.

Austria

The countries previously discussed were characterized by a reduced number of comparable firms, thus favouring the use of reference benchmarking. On the contrary, the Austrian distribution sector comprises over 130 DSOs which can be benchmarked (ECC, 2006; Cossent et al., 2009). In the regulatory period 2006-2009, the Austrian energy regulator (Energy Control Commission - ECC) performed benchmarking analyses by applying several frontier methods as described in (ECC, 2006). This case is particularly interesting because this is one of the few actual joint applications of reference benchmarking methods and frontier benchmarking methods.

The regulator used a so-called engineering economic analysis by designing and comparing a large number model networks in order to identify the relevant output variables to be considered in subsequent frontier benchmarking analyses. This approach can be considered as an application of the representative networks approach described in chapter 4. The results allowed the identification of different variables related to the peak load and the consumer connection density as major cost drivers. Separate variables were identified for different voltage levels. Moreover, regression studies were carried out so as to tests the significance of other environmental variables such as the share of underground cables over total network length.

However, ECC found it necessary to significantly reduce the sample size from 136 to 23 DMUs. This was due to the fact that several of the small DSOs did not own HV/MV substations. As a consequence, the output variable that measured the MV-LV peak load would have a value of zero for these DSOs, which would lead to numerical problems in parametric models[44]. In the end, this sample was reduced to 20 firms as a result of the removal of outliers. A problem stemming from this smaller sample was that SFA could not be applied as the sample size was not enough to ensure the significance of results. Consequently, two DEA models with CRS, including aggregate or broken down per voltage level customer density variables respectively, and a MOLS model were finally selected. The final efficiency score was computed as the weighted sum of the results of the three previous models.

The Austrian experience allows drawing several conclusions. Firstly, as mentioned above, this is an example of potential cooperation between reference and frontier benchmarking, where the results of the former feed as input data the latter analyses. This will presumably allow for the selection of the environmental variables that are more relevant to explain distribution costs. The large number of DSOs would in principle allow the regulator to use detailed frontier benchmarking models adequately reflected the heterogeneity across firms. However, it was also revealed how the differences in network architecture caused a significant reduction in the initially large sample size. Moreover, the existence of outliers in the data provided by some DSOs forced to reduce this even more. Hence, frontier benchmarking models had to be adapted accordingly.

United Kingdom

In the UK, there are 14 regional distribution companies of a similar size, which in some cases share the same ownership. This number could, in principle, limit the application of frontier benchmarking. Nonetheless, OFGEM has traditionally applied this kind of techniques to evaluate the cost efficiency of distribution companies. As an example, the cost assessment methodology applied during the last DPCR described in (OFGEM, 2009a; OFGEM, 2009b) will be discussed hereafter.

Controllable OPEX were primarily evaluated through OLS regression with three-year panel data using linear and log-log cost functions. According to the classification proposed in chapter 4, this would correspond to an average parametric benchmarking method. These cost functions were computed for several levels of cost disaggregation and cost drivers. Moreover, a frontier DEA model with VRS was used as a contrasting tool. The results yielded by the two approaches shows fairly consistent efficiency rankings. Additional comparisons were made by OLS linear regressions of OPEX and TOTEX using as independent variable a composite scale variable (CSV) reflecting the number of consumers, energy distributed and network length of each DSO. Data from Eastern US distribution companies were included as a form of international benchmarking. Lastly, several statistical tests were carried out to test the consistency of the models developed.

On the other hand, as described in chapter 4, the main regulatory tools to evaluate CAPEX efficiency, namely the asset replacement and the network reinforcement models, could be considered as a form of reference benchmarking. Since these models were already described previously in this thesis, no further details will be provided herein. Nevertheless, OFGEM's experience could be seen as another joint or complementary application of reference methods and black-box benchmarking. In this case, instead of running both types of models in series as in the Austrian approach, both techniques are

[44] The functional form selected by ECC requires calculating the logarithm of the variables values.

implemented in parallel addressing different types of costs. Despite the fact that this could imply neglecting some trade-off between OPEX and CAPEX, OFGEM deemed their necessary in order to overcome the limitations of conventional benchmarking models identified in previous price controls.

Peru

The last example that will be discussed is that of Peru, in order to illustrate the different conditions of this sector as compared to the European contexts described above. The Peruvian distribution sector comprises 20 DSOs. Five of these only operate networks in urban areas, whereas the remaining 15 operate mostly rural areas. Several of the latter companies supply less than 200000 customers, thus being unable to benefit from economies of scale and incurring in larger unitary costs. In addition to the differences in size, extremely large variations in load concentration can be found across DSOs (OSINERGIM, 2009). Another important aspect is that most Peruvian DSOs are publicly owned; private firms generally correspond to those supplying the urban areas. The relevance of these factors is confirmed by the results of an study presented in (Pérez-Reyes and Tovar, 2010) which showed that load concentration and ownership are very relevant variables to explain the efficiency of Peruvian distribution firms.

Since liberalization, the level of energy losses and the rates of access to electricity have improved significantly in Peru. Nevertheless, there is still plenty of work to do in order to ameliorate the level of continuity of supply and supply electricity to remote rural areas. Therefore, this is a context where significant network investments are required to address these limitations of current distribution grids.

The previous situation, characterized by a relatively small number of firms with great heterogeneity, creates important barriers for the use of frontier benchmarking, at least for CAPEX/TOTEX. Therefore, cost benchmarking has been conventionally based on the concept of model company, through which an adapted network for each DSO is obtained. In the case of Peru, an adapted network is obtained for each of the so-called typical network which allows the regulator to calculate standard unitary costs per kW and per customer for each sector. Note that each DSO can supply areas that correspond to different sectors. In the revision for the period 2009-2012, up to 207 distribution systems were studied resulting in the identification of 7 typical sectors through clustering techniques. This approach can be considered as another form of representative network. OPEX are remunerated on the basis of standard values for each type of asset and the efficient assets resulting from the previous analysis.

However, a consultancy work commissioned by the Peruvian regulator (OSINERGIM, 2009) suggested that this method could be jeopardizing certain firms due to the existing heterogeneity, especially considering the differences in size across firms and the intricate orography of Peru. This seems to be supported by the fact that the criteria to select the typical sectors have changed in every price review. The consultants proposed to exclude small DSOs from general incentive regulation provisions because the regulatory resources required would not compensate the potential efficiency gains. Moreover, their inclusion in benchmarking exercises could distort the results obtained. On the other hand, it was proposed to perform more individualized analyses for the remaining DSOs through a RNM similar to the ones used in Chile or Spain. Alternatively, the previous report suggests encouraging the integration of these small firms into larger ones so as to benefit from the economies of scale.

The Peruvian case shows that the specific environment faced by distribution companies can also determine the selection of the most appropriate reference benchmarking method. A potential improvement not addressed in detail by the aforementioned consultancy is how to benchmark OPEX across DSOs. The previous standard costs correspond to a form of index-based benchmarking, although it is not mentioned explicitly how the actual information gathered from the DSOs is used to determine these values. A potential modification could consist in the application of frontier methods for OPEX alone, similarly to how it has been done in the UK. The use of panel data, as done in (Pérez-Reyes and Tovar, 2010), could be helpful in this regard.

The contents of this chapter, together with the revision presented in chapter 4, allows concluding that black-box benchmarking, and frontier methods in particular, can be seen as the most conventional and widespread approach to regulatory benchmarking. Notwithstanding, in spite of the increased regulatory burden, reference benchmarking has been more recently introduced (or is being discussed) in several countries driven by the limitations of conventional methods when evaluating efficient network investments. These methods can be applied either as a direct benchmark to actual networks (e.g. Spanish experience), as relative reference networks (discussed in chapter 4) or as an input to another benchmarking technique (e.g. Austrian experience).

An additional conclusion that ought to be mentioned is that it must be borne in mind that both frontier method and RNMs are only regulatory tools which may be used in many different ways. A perfect example is that of Sweden, whose major drawbacks were inherent to the regulatory design rather than the tool itself. Since any benchmarking tool will never be capable of matching perfectly the actual situations faced by DSOs, some discretionary decisions will always be needed in real-life regulatory practice regardless of the tools used. Therefore, regulators should take into account that an appropriate regulatory design can be more important than the selection of benchmarking tool. Nonetheless, the latter must be done considering the pros and cons of each technique and analyzing in detail the conditions of the distribution sector and regulatory resources in their country or region.

6.4 Summary and conclusions

The focus of this chapter has been placed on comparing the existing benchmarking techniques, highlighting their main advantages and disadvantages. More specifically, three sets of comparisons have been performed. Firstly, frontier methods have been addressed. These techniques have been widely applied to electricity distribution and other sectors. Therefore, the pros and cons of the different frontier benchmarking approaches are very well known. On the contrary, reference methods, and norm models in particular, have rarely been compared with other methods or among them. Consequently, most of the contributions in this chapter have been devoted to the analysis of these methods.

Thus, the second analysis has focused on the comparison of the different reference methods. Comparing different reference methods is quite difficult due to the fact that scarce information is made publicly available. Moreover, quantitative comparisons are difficult to perform due to the different characteristics of the models and the inability to run them openly. In this chapter, only the Swedish NPAM and the Spanish RNMs have been qualitatively compared among them owing to the existing publications about these models. It has been shown that, in spite of being usually treated as a homogeneous group, norm models can present very distinct features. Broadly speaking, the Swedish NPAM generally performs stronger simplifications as compared to the Spanish RNMs. Notwithstanding, this is due to the fact that the model developers focused very much on the need to reduce the computational burden.

Lastly, the third study was devoted to the comparison of frontier methods versus norm models. The few publications dealing with this topic do not generally perform very detailed analyses as very little interaction seems to exist between the approach preferred by economists, frontier methods, and the one preferred by engineers, i.e. reference methods. Existing surveys suggest that in practice regulators are resorting to some form of reference benchmarking specially due to the need to assess investment needs.

Frontier benchmarking models are easier to develop and apply. This reduces the regulatory burden, facilitates price reviews and allows for easier replication of the results obtained. Additionally, they can incorporate all the different cost components into a single efficiency analysis, can take into account the historical evolution of actual grids and do not face technical limitations related to the size of the distribution area. However, the results greatly depend on the model specification and the number of firms being regulated. Furthermore, their inability to adequately reflect all the actual environmental conditions that DSOs face when planning and operating the distribution networks, the heterogeneity among firms and quality of service variables hampers their application to determine future investment needs. This limitation becomes particularly relevant as a result of the transition towards smarter distribution grids and the large-scale connection of DER.

On the other hand, the complexities of developing and maintaining norm models constitute their major drawback. This can effectively deter third-party participation in regulatory processes and transmit a lack of transparency. Moreover, norm models can only consider those aspects of the business directly related to the network. Therefore, additional analyses are required and some cost tradeoffs can be neglected. Nevertheless, the detailed modelling of network and load conditions represents a significant advantage of norm models, especially when assessing network investments. This can become particularly necessary in order to account for the impact of DER and the rapid technology changes ahead.

The previous discussions were illustrated through a description of the contexts and practical experiences with regulatory benchmarking in several countries. It can be concluded that frontier benchmarking and norm models present some complementarities, although further research and practical experience is needed to proof the potential synergies of both approaches as there is scope for cooperation among both regulatory viewpoints. Moreover, this review allows concluding that a more extensive use of reference benchmarking methods will presumably be needed in the coming future in order to evaluate investment requirements, especially due to the penetration of DER and the transition towards smarter grids. Finally, it is important to remark that both frontier method and norm models should be seen as regulatory tools to be used according the needs of regulators. No benchmarking tool can fit perfectly well the real life; hence, some discretionary decisions from the regulators will always be necessary. The actual conditions in each country or region will in the end condition the most suitable method to implement.

Main conclusions:

- The pros and cons of frontier benchmarking methods are widely known. However, reference methods have rarely been compared with other methods or among them
- Quantitative comparisons among norm models are not possible due to the different characteristics of the models and the inability to run them openly. Thus, a qualitative comparison has been made, showing that norm models can be significantly different
- Existing surveys suggest that in practice regulators are resorting to some form of reference benchmarking mainly due to the need to assess investment needs
- As compared to norm models, frontier methods are easier to develop and apply. Additionally, they can incorporate all the different cost components into a single efficiency analysis and account for the historical evolution of actual grids. However, results greatly depend on the model specification and number of firms. Furthermore, they fail to adequately capture the impact of environmental conditions and firm heterogeneity
- Norm models are complex to develop and maintain and can only consider network related aspects. Nevertheless, they are more suitable to assess network investments and account for the impact of DER and new technologies
- Further research and practical experience is needed to exploit the complementarities between both approaches. The selection of the most suitable method will in the end depend on the conditions in each country/region

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7. Continuity of supply in distribution networks and its regulation

As mentioned in previous chapters, incentive regulation has brought about the need to regulate quality of service because regulated firms may reduce their costs at the expense of quality. Therefore, specific regulatory mechanisms have been frequently introduced (Giannakis et al., 2005; Joskow, 2005; Ter-Martirosyan and Kwoka, 2010). However, this is not a straightforward task. Before going into further details about how to regulate quality of service, quality of service in the context of electricity distribution will be defined first.

Broadly speaking, quality of electricity service comprises commercial quality and technical quality or quality of supply. At the same time, the technical aspects of quality can be divided into power or voltage quality and continuity of supply (Eurelectric, 2006; CEER, 2010). These three main components of quality of service in electricity distribution can be defined as follows:

i. **Commercial quality:** this term refers aspects related to customer attention, i.e. how fast and appropriately DSOs respond to customers' requests.

ii. **Power quality:** this refers to distortions in the voltage wave shape, frequency or magnitude that may produce problems in the functioning of electrical devices and appliances.

iii. **Continuity of supply:** continuity is concerned with the reliability of electricity supply. In distribution networks, it is the lack of continuity of supply that is commonly monitored. The temporary unavailability of electricity is measured through some indicator of the number and duration of supply interruptions.

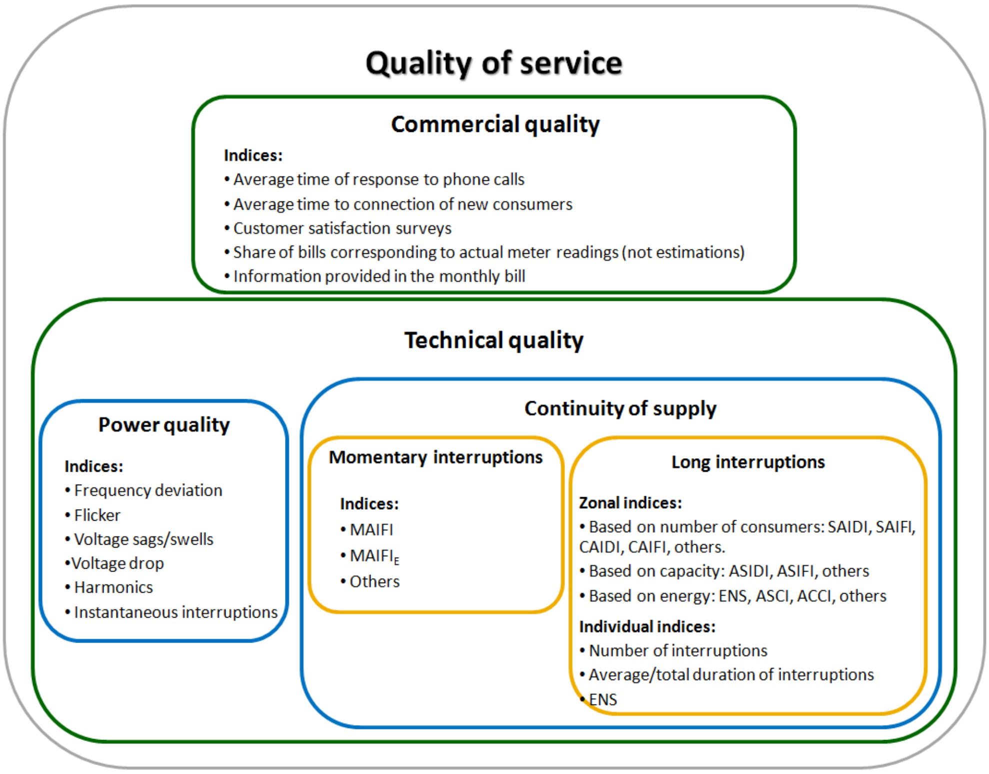

Figure 7-1: Quality of service in electricity distribution networks

Figure 7-1 shows the different aspects of quality of service and indicators that are used to measure it. The indicators related to continuity of supply will be described in more detail in section 7.1.

The lack of power supply is defined as the absence of adequate voltage levels at the point of connection to the grid. Depending on the duration of this voltage unavailability, interruptions can be sorted into three groups: transient or instantaneous, short or momentary and long or sustained interruptions. Generally, transient interruptions are associated with power quality problems, whereas momentary and sustained interruptions are associated with continuity of supply.

However, the definition of each type of interruption, and whether these are recorded, can vary among countries or regions. For instance, the most common value for the threshold between momentary and long interruptions is 3 min in European countries (CEER, 2012). Nonetheless, in the US this value is 1 min (McDermott and Dugan, 2003). Moreover, even documents published by the same institutions may present contradictory definitions. For instance, the definition of momentary interruptions provided in the IEEE Standard 1366 (IEEE, 2001) slightly differs from the one in IEEE Standard 1159 (IEEE, 2009). As mentioned in (McDermott and Dugan, 2003), the interruptions considered to compute reliability indices for momentary interruptions as defined in (IEEE, 2001), e.g. MAIFI, would comprise what (IEEE, 2009) refers to as temporary and momentary interruptions. Defining a precise threshold for the different types of interruptions falls outside the scope of this document. Therefore, hereinafter the terms instantaneous, momentary and long interruptions will be used in a generic form.

The main focus of the economic regulation of DSOs is generally placed on continuity of supply due to several reasons. Customer attention in distribution networks (meter reading frequency, time to connect a new consumer, etc.) is still an important aspect that should be monitored and regulated to prevent DSOs from neglecting it. This is why some regulators have set economic incentives for DSOs to improve customer attention (OFGEM, 2009). Nevertheless, the liberalization of the power sector has placed many responsibilities concerning commercial quality on the retailers instead of DSOs. Moreover, the regulation of commercial quality does not require such a profound knowledge of the specific network activities of DSOs. Hence, its regulation is not significantly different to that in other sectors. On the other hand, power quality problems are mostly created by certain loads connected to the distribution grid and some malfunctioning of protection and control equipment. Hence, power quality is most commonly controlled through grid codes and standards, thus falling outside of the scope of economic regulation.

Finally, continuity of supply is intimately related to the investments in distribution networks and operating and maintenance practices. Hence, continuity of supply can be significantly affected by cost reduction strategies driven by incentive regulation. Furthermore, most of the interruptions suffered by electricity consumers are originated in distribution networks, which may account for 80-95 % of the interruptions depending on the country and the time period (Gómez-Expósito et al.; Rivier, 1999). Due to all these, continuity of supply is the aspect of quality most frequently controlled through the economic regulation of DSOs under incentive regulation schemes. Consequently, this chapter will place the emphasis specifically on the regulation of continuity of supply in electricity distribution networks.

The remainder of this chapter firstly describes the main indicators used to measure continuity of supply in section 7.1. Section 7.2 provides an overview of the theoretical background and the main approaches to the regulation of continuity of supply in distribution networks. The actual implementation of the previous theoretical framework is hampered by several barriers. These barriers and possible solutions are dealt with in section 7.3. Subsequently, the implications of the penetration of smart grid technologies and the large-scale connection of DG with regard to the regulation of continuity of supply will be analysed and discussed in sections 7.4 and 7.5 respectively. Lastly, section 7.6 will summarize the main conclusions drawn from the chapter contents.

7.1 Measuring continuity of supply

The measurement of continuity of supply constitutes a prerequisite to the implementation of any regulatory mechanism. In transmission networks, it is common to compute the availability rate of each network component and its consequences on power interruptions. However, the huge number of different network components that can be found in distribution networks greatly hampers to do this. Consequently, in practice, continuity of supply itself is not easy to measure in distribution grids. Therefore, it is more common to measure the lack of continuity, i.e. supply interruptions. This is done through some reliability indices that are computed on the basis of the interruptions experienced by electricity consumers connected to a distribution network in a certain geographical area during a certain period of time, being typically one year (CEER, 2012).

Firstly, it is necessary to determine what interruptions are considered to compute these indices for regulatory purposes. Power supply interruptions can be classified according to whether their occurrence was known in advance or the degree of responsibility that can be attributed to DSOs. Thus, it is frequent to talk about planned and unplanned interruptions. Planned interruptions are those that have been foreseen in advance by the distribution company and communicated to the consumers involved. This kind of contingencies has a less severe impact of consumers as they are given time to take preventive measures. Therefore, the incentives/penalties associated with planned interruptions are generally more lenient than those related to unplanned interruptions. The conditions under which a specific interruption can be considered as planned (e.g. publication in the media, minimum notice time, etc.) should be clearly defined by regulation.

Additionally, some distribution network contingencies may be caused by severe weather conditions or external sabotage outside the control of DSOs. These are normally named force majeure interruptions and are usually subtracted from the computation of reliability indices when determining regulatory incentives. Even though that all these contingencies can be measured, it is mostly unplanned interruptions whose origin lies in the failure of distribution network components that are subject to regulatory control.

The next decision is to select what indicators to monitor and regulate. As illustrated in Figure 7-1, reliability indices can be computed at the level of each single consumer or aggregated for a wider distribution area. Both types of indices serve different purposes. Individual indices are measured and controlled to prevent the existence of consumers with very poor quality within a distribution area where average continuity of supply may be adequate. These regulatory mechanisms are normally called minimum quality standards (MQS) (Fumagalli et al., 2007) or guaranteed standard (GS) (Alvehag and Soder, 2011). The variables that can be monitored comprise the number or duration of the interruptions experienced by a specific consumer over one year or the expected amount of energy that the consumer would have demanded during those interruptions.

On the other hand, zonal or system indices allow controlling average performance across a specific region. The level of detail with which reliability indices are computed greatly varies among countries. The aspects that may differ are the voltage levels monitored, the type of interruptions considered, whether results are published per each DSO or per region, etc. An extensive review of all these issues in European countries can be found in (CEER, 2012). The major reliability indices used for regulatory purposes are defined in (IEEE, 2001). These are summarized in Table 7-1.

	Load based	Customer based		Energy based	
	All customers served	All customers served	Only customers interrupted	All customers served	Only customers interrupted
Frequency of interruptions	ASIFI, NIEPI	SAIFI	CAIFI	ENS ASCI-AENS	ACCI
Duration of interruptions	ASIDI, TIEPI	SAIDI	CAIDI, CTAIDI		

Table 7-1: Summary of the main reliability indices

The customer-based and load-based indices measure the number or duration of the interruptions experienced by an average consumer (SAIDI, SAIFI) or kW of demand (ASIDI-TIEPI, ASIFI-NIEPI) respectively. Additionally, these indices may be computed considering only those consumers that are actually interrupted (CAIDI, CAIFI). Customer-based indices are appropriate when all consumers are similar. Nonetheless, load-based indices may be more appropriate in order to account for the different sizes that can be found among consumers, for instance between residential and industrial consumers (McDermott and Dugan, 2003).

Finally, an alternative way to quantify the reliability of a distribution grid consists of estimating the amount of energy that would have been supplied to a customer if there had not been any interruption, either aggregated at system level (ENS) or averaged across total consumers (ASCI-AENS) or across the consumers that actually experienced an interruption (ACCI). The main drawback of energy-based reliability indices lies in the fact that their computation requires estimating how consumers would have behaved in case no interruption would have occurred, which requires certain discretionary assumptions. This is usually done through standard load profiles for each type of consumer.

7.2 Regulation of continuity of supply: background and major incentive mechanisms

This section describes the theoretical background that should be considered to set an appropriate framework to regulate continuity of supply and the main regulatory incentive schemes addressed to encourage DSOs to improve continuity of supply.

7.2.1 Theoretical background

Electricity consumers incur certain costs or experience some loss of comfort or utility as a result of supply interruptions. For example, industries may see their production abruptly halted with considerable economic losses, residential consumers may see the contents of their fridges ruined or bars and restaurants may not be able to serve their customers. Therein lies the importance of reducing the interruptions suffered by end consumers. Nevertheless, improving continuity of supply involves making investments in distribution networks or performing maintenance works on grid components. For example, increasing the redundancy in the grid through additional feeders or implementing preventive maintenance actions would yield better levels of reliability. This means that continuity of supply can be improved at the expense of increasing distribution costs.

The optimal level of continuity of supply would be that which minimises the total social costs of interruptions. These can be computed as the sum of the investments and operational costs incurred by DSOs to maintain or improve quality levels plus the costs for consumers caused by the supply interruptions. This increase in distribution costs needed to improve quality should in the end be borne by end consumers since they are benefiting from this quality increase. Notwithstanding, consumers should not pay for increasing the quality beyond the point where the total social costs are minimised. Hence, DSOs should not be incentivised to improve quality beyond this point either. Consequently, the regulation of continuity of supply should comply with the following requirements:

i. Encourage DSOs to drive levels of continuity of supply towards the optimal level where total social costs are minimised, and not beyond that point.
ii. Set the remuneration of DSOs in line with the levels of quality actually provided to consumers.
iii. Allocate the cost of improving continuity of supply to the consumers benefiting from this improvement, up to the optimal level of quality.

Figure 7-2 depicts these two cost curves, where the horizontal axis represents a generic quality variable that increases throughout the axis. Empirical evidence suggests that both curves are qualitatively as shown in the figure (Kariuki and Allan, 1996b; Kariuki and Allan, 1996a; Sullivan et al., 1996; Kjolle et al., 2008; Chowdhury et al., 2009; Jamasb et al., 2010; Fernandes et al., 2012). Poor levels of quality have a strong impact on consumers, thus implying very high costs. However, as quality levels improve this value steadily decreases. On the contrary, the costs required to provide a poor quality are very low, but increase as more investments and operational costs are needed to improve quality levels. Moreover, the marginal cost of improving quality will grow with the levels of quality, i.e. the higher the quality of service, the more expensive it is to improve it further. In mathematical terms, this implies that both curves and their derivatives are increasing functions with the quality variable.

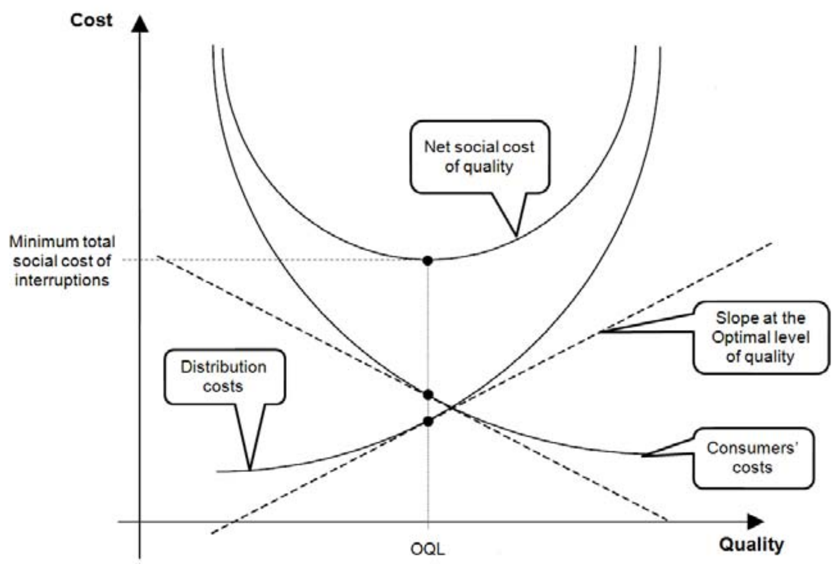

Figure 7-2: Optimal level of quality of service (OQL)

It is straightforward to prove that the optimal level of quality is reached at the point where the derivatives of both cost functions are equal in absolute terms. The net social costs (*NSC*) are obtained as the sum of the distribution costs (*DC*) and the consumers costs (*CC*) as shown in (7-1). The minimum of *NSC*, which corresponds to the optimal quality level (*OQL*), would be in the point where its derivative with respect to quality turns zero (7-2). Furthermore, the marginal cost of improving quality is always lower than the value *K* for quality levels below the optimal, whereas marginal improvement costs exceed *K* for points beyond the optimal level of quality.

$$NSC = DC(Q) + CC(Q) \tag{7-1}$$

$$\left.\frac{\partial DC(Q)}{\partial Q}\right|_{OQL} + \left.\frac{\partial CC(Q)}{\partial Q}\right|_{OQL} = 0 \Rightarrow \left.\frac{\partial DC(Q)}{\partial Q}\right|_{OQL} = -\left.\frac{\partial CC(Q)}{\partial Q}\right|_{OQL} = K \tag{7-2}$$

7.2.2 Incentive schemes to regulate continuity of supply

The regulatory approaches to continuity of supply essentially intend to make DSOs internalize the cost of interruptions for consumers so that these are included into their investment and operational decisions. Several distinct regulatory interventions related to continuity of supply can be found. The simplest mechanism would merely consist in publishing the actual levels of interruptions so as to make DSOs face public scrutiny. Another alternative approach is to include quality in black-box benchmarking models as proposed by (Giannakis et al., 2005). Similarly, reference networks can be used to set the allowed revenues in accordance to the reference levels of quality (Strbac and Allan, 2001; Ajodhia, 2005).

However, none of the previous mechanisms explicitly preclude DSOs from cutting expenses at the risk of a quality deterioration. Therefore, specific incentives to keep improving quality or at least avoid its deterioration are deemed necessary. This is generally done through some kind of output oriented incentives in line with the ones described in chapter 3. The remainder of this section will present the main incentive mechanisms used to regulate continuity of supply in distribution grids, whereas practical implementation issues will be addressed in section 7.3.

7.2.2.1 Bonus-malus mechanisms to regulate continuity of supply at system level

The main incentive mechanisms implemented to prevent DSOs from neglecting the levels of continuity of supply correspond to a bonus-malus scheme which penalizes DSOs that fail to attain a pre-determined level of quality and vice versa. These schemes aim at ensuring that DSOs prevent the existence of high overall levels of interruptions at system level. This is done through the aggregation and averaging of the effects of interruptions across all the consumers in the system or region being analyzed.

The levels of continuity of supply are measured through some reliability indices and the incentive/penalty scheme results in a lump sum that is added or subtracted from the overall revenue allowances of each DSO, usually annually. The regulator essentially needs to determine two parameters, i.e. the reference levels and the incentive rate. The design of these incentives may vary significantly across countries, as illustrated in (CEER, 2012) for the European countries. In any case, the reference values, sometimes referred to as target values, should not correspond to the optimal level of quality but to a level consistent with the current allowed revenues. Moreover, as explained in chapter 3, the reference values only affect to the distribution of the benefits from quality improvements between consumers and DSOs, not the power of the incentive itself. On the other hand, depending on the type of incentive rate implemented, these can be broadly categorized into two main categories: linear incentives and non-linear incentives. Hereinafter, the theoretical considerations that should drive the design of these two types of incentives will be presented and discussed.

7.2.2.1.1 Linear incentive schemes

The basic design of a linear incentive scheme is shown in (7-3). These are characterized by the fact that the amount of the total incentive or penalty is proportional to the deviation with respect to the reference value set for one or more reliability indices. This is the kind of design implemented in countries such as Spain, Portugal, Sweden or the UK (OFGEM, 2009; Alvehag and Soder, 2011; Cossent et al., 2011b).

$$Inc = Rate \cdot \left(Q_{ref} - Q_{real}\right) \qquad (7\text{-}3)$$

Where:

Rate Constant incentive rate expressed in monetary units per unit change in quality indicator, e.g. €/kWh$_{\text{Non-supplied}}$

Q_{ref} Reference level for quality indicator

Q_{real} Measured value for quality indicator

The appropriate design of linear incentives is described in detail in (Rivier, 1999). Therein, the author proves that the incentive rate in a linear incentive mechanism should be set equal to the marginal cost of improving continuity of supply at the optimal level of quality where total social costs are minimized. Thus, the DSOs would keep reducing the interruptions until the level where the incentive they receive falls below the marginal cost of increasing the levels of continuity of supply. At the same time, consumers would benefit from this improvement since the money they would be paying to DSOs as an incentive would be lower than the reduction in the costs of the interruptions they suffer.

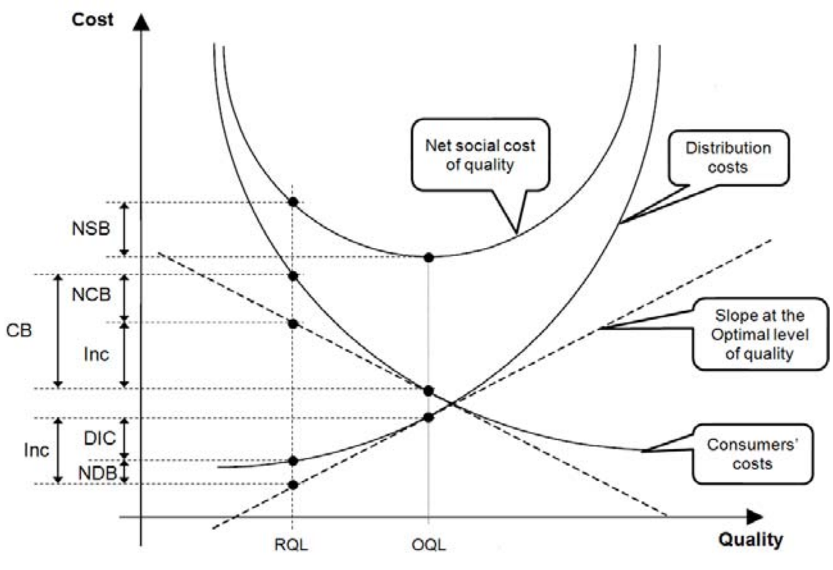

Figure 7-3: Benefit allocation with an optimal linear incentive scheme with a reference value equal to current levels of continuity of supply

This effect is illustrated in Figure 7-3, where it can be seen that the total net social benefit (NSB) is shared between DSOs, who perceive a net DSO benefit (NDB) despite incurring in certain costs (DIC), and consumers, who earn a net consumer benefit (NCB) despite paying an incentive (Inc). DSOs could be tempted to reduce the interruptions beyond the optimal level of quality in order to earn a higher incentive. However, as shown in Figure 7-4, this incentive design would effectively discourage this behaviour since the incentive they would be paid (ΔInc) would be lower than the costs incurred (ΔDIC). This figure shows that the reduction in net social benefit (-Δ**N**SB) would be borne not only by consumers but also by DSOs.

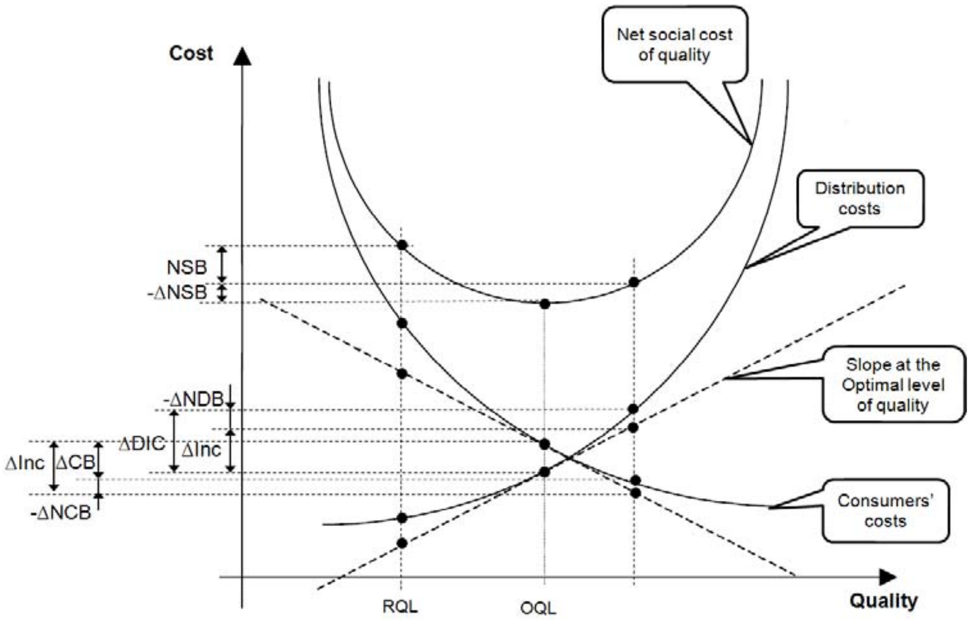

Figure 7-4: Going beyond the optimal level of quality with a linear incentive scheme

The linear incentive scheme is the most commonly applied in electricity distribution since it is easier to implement. However, the optimal design of a linear incentive rate requires knowing both cost curves in detail. Otherwise it would not be possible to know where the optimal level of quality so as to compute the derivatives of the curves at that point. These curves are unknown to the regulator. Therefore, several methods have been developed to estimate both curves. These will be described in more detail in section 7.3.1. However, whilst the approaches to estimate the costs of interruptions for consumers are widely applied, the costs incurred by DSO to improve continuity of supply have been scarcely analyzed and used by regulators. Consequently, it may be concluded that the actual incentive schemes used by regulators correspond to a suboptimal design. This makes it necessary to carefully monitor the evolution of continuity of supply indicators over time to fine-tune the incentives.

Furthermore, a linear incentive scheme allows regulators to set reference values at current quality levels as consumers will still perceive a benefit as proved by Figure 7-3. The next subsection will show that this may not be the case with non-linear incentives.

7.2.2.1.2 Non-linear incentive schemes

As shown in (7-4), non-linear incentive schemes are characterized by the fact that the incentive rate varies with the actual level of continuity of supply provided by DSOs by following the customer interruptions function estimated by the regulator, *f(Q)*. This function would be an approximation to the unknown actual customer cost function, *CC(Q)*, presented in equation (7-1). Non-linear incentive schemes are applied in countries such as Norway (Growitsch et al., 2010) or Italy (AEEG, 2011).

$$Inc = f(Q_{ref}) - f(Q_{real}) \tag{7-4}$$

Where:

$f(Q_{ref})$	Value of the customer interruption function for Q_{ref}
$f(Q_{real})$	Value of the customer interruption function for Q_{real}

Non-linear incentive schemes make DSOs internalize the full cost of interruptions for consumers into their investment and operational decisions. Therefore, the incentive rate decreases as higher quality levels are achieved and vice versa. This way, DSOs would incur in costs to reduce interruptions until the total social costs of interruptions are minimized. Beyond this point, DSOs would see their net benefits decrease owing to the fact that the incremental costs exceed the incremental incentive. Figure 7-5 depicts a non-linear incentive scheme where the incentive rate is made to follow at all times the marginal costs for consumers that are derived from power supply interruptions. It can be seen that it is possible to attain the optimal level of quality through this incentive design.

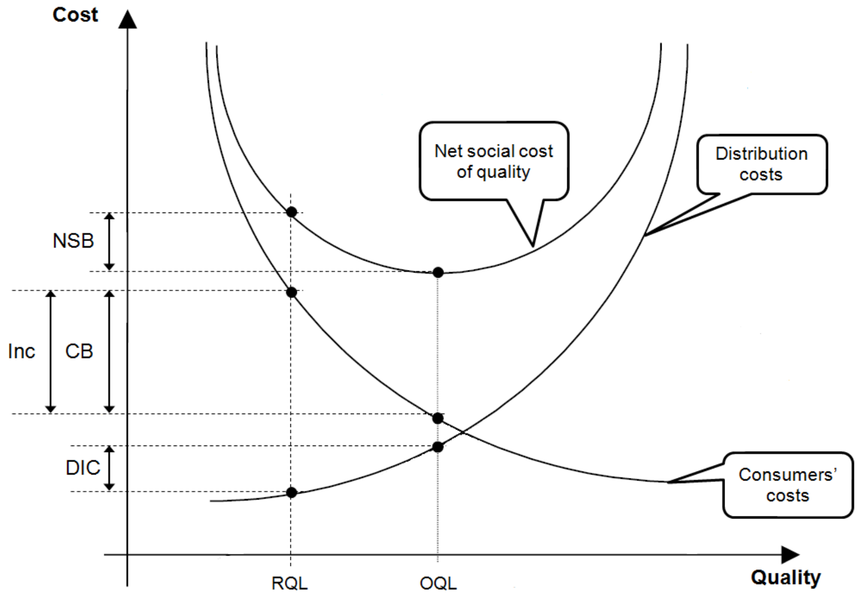

Figure 7-5: Benefit allocation with a non-linear incentive scheme with a reference value equal to current levels of continuity of supply

The design of non-linear incentives is much more complicated as the incentive rate is made dependent on several factors such as the type of consumer (domestic, commercial, industrial, etc.), the time of day or season when each interruption took place, whether interruptions were planned or unplanned, etc. Hence, a deep knowledge of the mix of consumers in each area and a more detailed record of interruptions (differentiating per time of day, type of consumer, etc.) is required. This may be challenging both to regulators and to DSOs alike. Notwithstanding, non-linear incentives presents a major advantage over linear ones. Since the incentive rate is completely independent on the cost curve of the DSO, it is not necessary to estimate this curve. Consequently, an optimal design can be ensured by estimating only the consumers' interruption cost functions. This is a relevant feature given that there is much more literature and practical experience in the estimation of these curves, as compared to the distribution cost curves.

Additionally, it can be seen that the amount of the incentive (or penalty) received by DSOs under this method is larger than in the case of linear incentives for the same improvement (or deterioration) in quality. For quality levels below the optimal, the marginal incentive received by DSOs will always be higher with no-linear incentives. These marginal values would become equal at the optimal level of quality. This would serve to provide DSOs with stronger incentives to improve continuity of supply. However, in case the reference value is set equal to the current continuity of supply (QL^0) consumers would not be benefiting from this quality improvement because DSOs would be retaining all the net benefits derived from it. As illustrated in Figure 7-5, the whole consumer benefit (*CB*) would be paid to DSOs as an incentive (*Inc*), which is equal to the DSO expenditures (*DIC*) plus the net social benefit (*NSB*).

Therefore, an equitable distribution of the gains in net social benefit between DSOs and consumers would require setting reference values higher than the initial continuity levels. Figure 7-6 shows that by doing this, consumers only pay a fraction of their total benefits (*CB*) as an incentive to DSOs (*Inc*), thus retaining a certain net consumer's benefit (*NCB*).

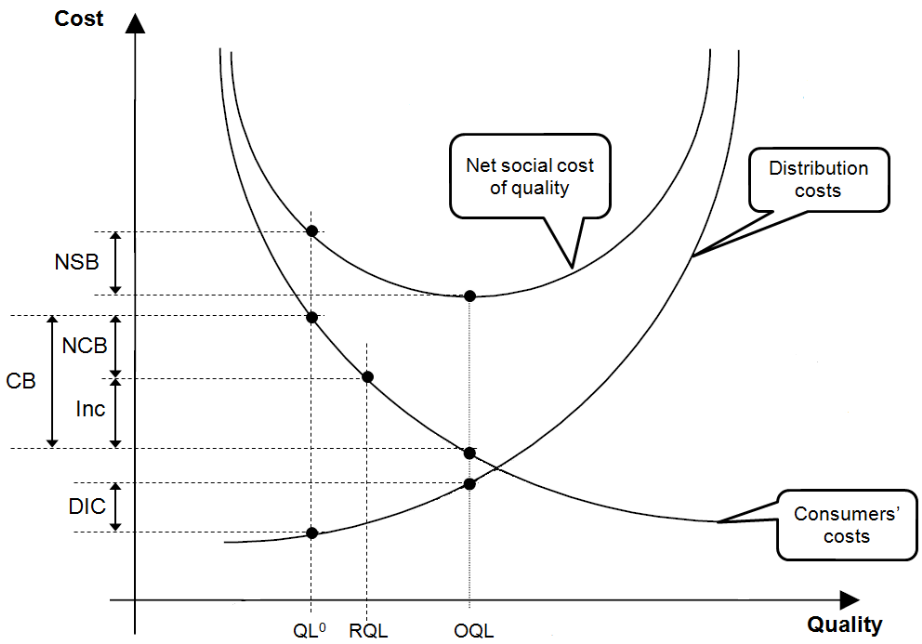

Figure 7-6: Benefit allocation with a non-linear incentive scheme with a reference value higher than current levels of continuity of supply

7.2.2.1.3 Discussion

Previous sections have described two theoretical frameworks that allow regulators to set optimal regulatory incentives for the improvement of continuity of supply. Linear incentives are the most widely used, presumably due to its simplicity. Moreover, these linear incentives can be applied by using any of the reliability indices presented in section 7.1. For example, the indices used comprise TIEPI/NIEPI in Spain, CML/CI in the UK, END in Portugal or SAIDI/SAIFI in Sweden. Nonetheless, as previously stated, the lack of analyses on the costs incurred by DSOs to improve continuity of supply, as required to ensure an optimal level of incentive, suggests that current incentive schemes may lead to suboptimal designs. Notwithstanding, significant improvements can be attained even with a suboptimal design, particularly when initial levels of quality are poor as in the case of Portugal (ERSE, 2008).

On the other hand, some countries have implemented more sophisticated incentives that are based on a function that quantifies in detail the monetary consequences of interruptions for consumers. Thus, not a single reliability index is used but a complex cost function. For instance, the Italian unit incentives depend not only on the location of the consumers (voltage level, load concentration) as it is frequent in linear incentives, but also on the frequency and duration of the interruptions suffered by consumers. Thus, the penalties faced by DSOs increase with the frequency and duration of the interruptions experienced by end consumers measured by SAIDI and SAIFI (AEEG, 2011). On the other hand, the Norwegian incentives depend on several factors such as the type of customer (residential, commercial, industrial), time of day of the interruption, day of the week or duration of the interruption (Growitsch et al., 2010; Alvehag and Soder, 2011).

7.2.2.2 Individual compensations to consumers

The existence of bonus-malus mechanisms over system reliability indices ensures that DSOs internalize into their investment and operational decisions the interruptions experienced by the consumers connected to their grids. However, there may still exist specific consumers that suffer from very frequent or long interruptions despite the fact that continuity of supply is adequate on average owing to the presence of consumers enjoying very high quality levels (Rivier and Gomez, 2000; Fumagalli et al., 2007).

In order to avoid this, DSOs should pay compensations to those consumers which are supplied under clearly insufficient quality conditions (Carvalho and Ferreira, 2005). In fact, the 5th CEER Benchmarking Report on quality of service shows that most European countries have implemented these compensations. Contrary to the previous incentive schemes, individual standards are not corrections to the remuneration of DSOs recouped through network tariffs, but as a penalty paid directly to those end consumers to compensate them for the poor quality received. Hence, due to the purpose of these compensations, it is to be expected that compensations to individual consumers do not have a major effect on the overall remuneration of DSOs under normal circumstances.

Figure 7-7 depicts the intended effects of both individual MQS and system reliability incentives. In the figure, DSO A would be subject to both mechanisms, thus achieving an optimal average level of quality and a reduced number of consumers experiencing very low quality levels. On the other hand, it is shown that DSO B presents a much larger number of consumers with poor quality levels in spite of achieving a mean optimal quality level. This is caused by the lack of guaranteed individual standards. Finally, DSO C delivers an average quality level below the socially optimal one, although the number of consumers who receive a very low quality is quite reduced. This would be the situation where only individual standards are implemented.

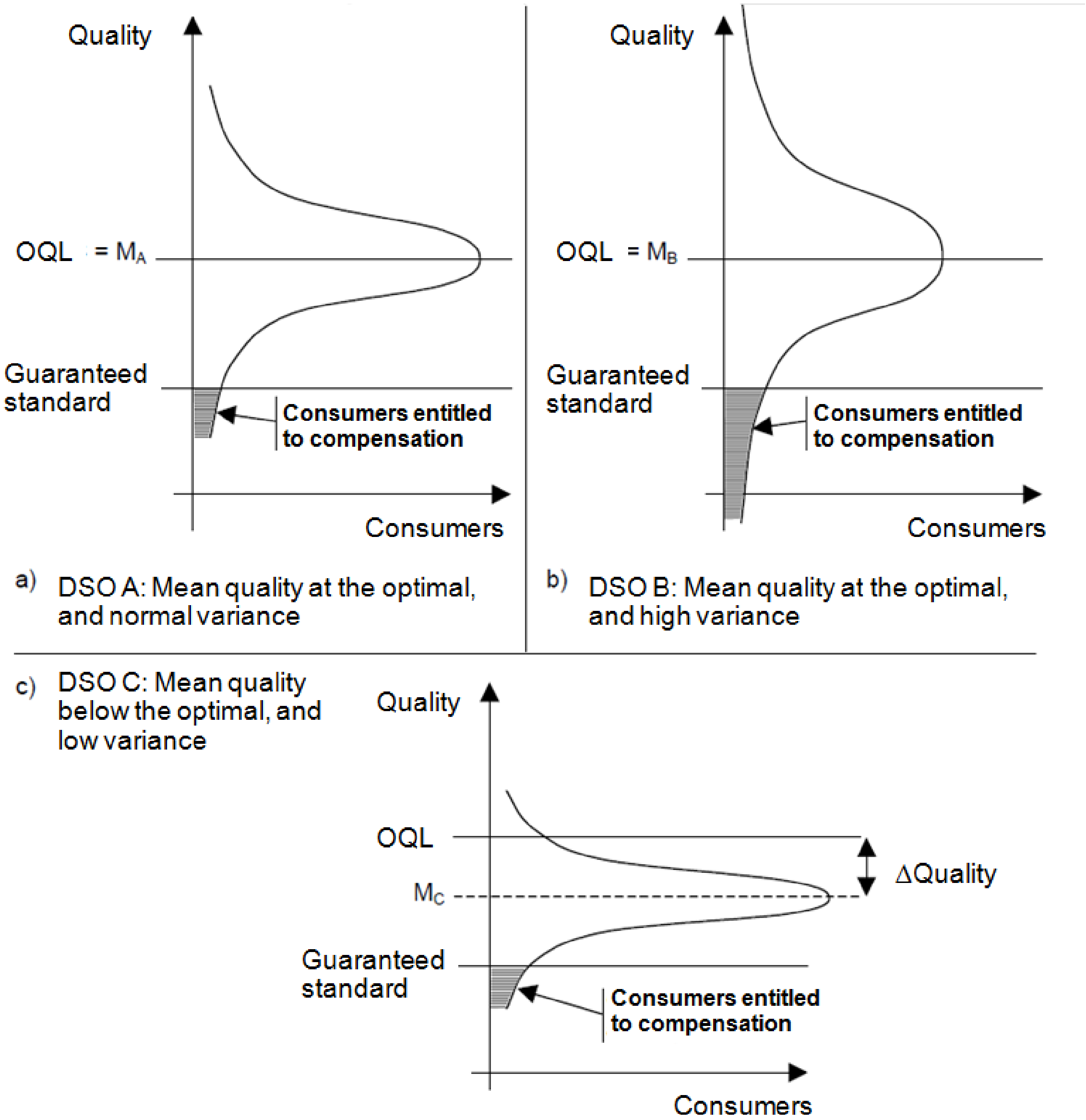

Figure 7-7: Combining system reliability incentives with individual standards (Rivier, 1999)

DSOs may have to compensate those consumers that see their power supply interrupted more than a certain number of times or longer than a certain duration per year or month. Moreover, it is frequent to differentiate between different types of consumers either according to their activity (domestic, industrial, commercial), the voltage level they are connected to or the type of area (urban, rural).

MQS are necessary when linear incentives are in place in order to prevent the existence of worst-served consumers. However, in case non-linear incentives are used, the presence of worst-served consumers can be directly taken into account into the interruption cost function used by the regulator. This is typically done by setting a very high valuation of quality for very long interruptions. Nonetheless, in this case these penalties paid by DSOs would be distributed across all consumers instead of directly compensating worst-served customers. Therefore, an alternative approach would consist in using GS to specifically compensate worst-served consumers as a complement to non-linear incentive schemes. Note that under both approaches, DSOs would face the same penalties. Notwithstanding, the distribution of this money across consumers connected to the distribution grid would be different.

7.2.2.3 Premium quality contracts

A final mechanism to regulate continuity of supply in that of premium quality contracts or reliability insurances (Fumagalli et al., 2004; Fumagalli et al., 2007). It consists in offering end consumers a contract through which they would be entitled to higher levels of quality in exchange for a premium. In case the DSO fails to deliver such level of quality, consumers are entitled to receive economic compensation. The main advantage of premium quality contracts is that consumers have to directly estimate the value of quality for them. However, they are difficult to apply extensively due to the free-riding effect that derives from the fact that DSOs may find it impossible to provide higher levels of quality only to the consumers who have signed these contracts (Fumagalli et al., 2007). For example, increasing network redundancy would affect all the consumers in that area. Hence, premium quality contracts have only been used in France and Italy for certain consumers.

7.3 Practical issues when setting incentives to improve continuity of supply

The previous section described the main regulatory mechanisms to control continuity of supply in distribution networks from a general theoretical perspective. Nevertheless, in real-life regulators have to face many practical difficulties that hamper the implementation of the former framework. This section will review the main hurdles to be confronted when computing the incentives for DSOs to reduce the number and duration of interruptions, especially concerning system bonus-malus reliability incentives.

7.3.1 On the estimation of the DSO and consumers cost curves

Estimating the curves representing the costs for consumers arising from the lack of continuity of supply and the costs incurred by DSOs to improve quality of service constitutes an essential task when regulating continuity of supply. Since these curves are unobservable for the regulator, several methods have been developed to estimate them.

7.3.1.1 Cost of interruptions for consumers

Power supply interruptions can cause several damages to end consumers. These comprise actual tangible costs (loss of production, equipment damage, material spoilage), other indirect costs (loss of market share) and other non-economic welfare loss (lack of comfort, health risk, loss of leisure time) (Linares and Rey, 2012). Ideally, all kinds of costs should be considered, although some methods are better suited to estimate direct economic effects, whereas other may capture indirect and social costs. (Ajodhia, 2005) presents a thorough review of the existing methods to estimate the cost of interruptions for consumers and their main pros and cons. Following (Rivier, 1999; Linares and Rey, 2012), three main approaches can be found:

- Macroeconomic analyses: these methods combine macroeconomic indicators such gross domestic product, electricity consumption per sector or average national wages to estimate the value of lost load for different economic sectors. This approach requires scarce resources and data. However, the accuracy of the results is arguable due to the heavy simplifications it requires.
- Direct studies of actual blackouts: these methods analyze the consequences of actual past events when major blackouts took place. The direct analysis of past

incidents makes it easier to estimate the costs of interruptions and provide fairly accurate results. Nevertheless, these will be very specific to the actual circumstances (duration of the interruption, extent, time place, etc.) and may be difficult to extrapolate.

- Surveys to end consumers: the last approach consists in carrying out surveys among end consumers to obtain information about how they value electricity supply. Several types of surveys can be found. Firstly, some surveys ask consumers about the direct costs they would incur under different types of interruptions. This method is suitable for industrial and large consumers who are more aware about the consequences of interruptions. However, residential or commercial consumers may experience less tangible consequences from the lack of power supply. That is why surveys about their willingness-to-pay (WTP) to avoid an interruption or their willingness-to-accept (WTA) a compensation for lower quality are preferable in this case. Note that the WTP and WTA should in principle be equal. However, since electricity is perceived as a public good, the WTP estimated is generally much lower than the WTA. Thus, these two parameters could be considered as a lower and upper bound of the value of quality for consumers respectively. The last of surveys one may find comprises those aiming to estimate the cost of alternative measures to mitigate the effects of interruptions such as insurance policies, back-up generation, candles, etc. Generally, survey methods are the ones that provide more accurate and reliable results. However, they require extensive resources and costs.

Survey-based methods, either based on direct worth assessment or WTP/WTA estimations, are the most widespread in the electricity sector. In fact, CEER recommends to use these methods in regulation for most consumers (CEER, 2010). Furthermore, a literature review shows that these are the most commonly applied methods (Kariuki and Allan, 1996b; Sullivan et al., 1996; Nam et al., 2006; Yu et al., 2007; Kjolle et al., 2008; Chowdhury et al., 2009; Kjolle et al., 2009; CEER, 2010; Linares and Rey, 2012). Additionally, it can be concluded that the customer valuation of continuity of supply can change significantly across different types of consumers, the duration of the interruptions, notice time, time of day and country or region.

This presents two main regulatory implications. On the one hand, it is advisable to carry out survey analyses for each country instead of relying on international studies or regulations. On the other hand, incentive schemes should take into account the different factors that influence the effects of interruptions on consumers. These can be incorporated relatively easy into non-linear schemes as shown by the progressive integration of different factors into the Norwegian continuity regulation (Kjolle et al., 2009; Growitsch et al., 2010; Alvehag and Soder, 2011). However, this is not as straightforward under the linear incentive schemes, which normally just exclude planned or force majeure interruptions from the computation of the system reliability indices. Moreover, introducing these additional differentiations in linear incentive schemes could imply losing one of their major advantages, which is their simplicity.

7.3.1.2 Distribution costs to improve continuity of supply

A reliable power supply requires DSOs to incur certain expenditures, which can be classified into two major groups: first and second order expenditures (Rivier, 1999). First order expenditures are those necessary to ensure the connectivity of all network users. Thus, first order expenditures essentially comprise substations, transformers and lines. On the other hand, the second order expenditures are those that aim to ensure adequate levels of network reliability by reducing the failure rates of network components, increasing grid redundancy, reducing fault location and restoration times, etc. Second order expenditures include investments in protection, switching and monitoring devices as well as certain operational expenditures such as maintenance crews or preventive maintenance actions.

In principle, reliability analyses should focus on second order expenditures. However, in practice it is difficult to define a sharp frontier between both categories because network configuration and topology, which would be initially related to first order expenditures, can have a significant impact on reliability. For instance, increasing the number of substations to supply the same users would also deliver a higher reliability. Additionally, underground lines are more expensive than overhead ones, but usually present lower failure rates (and have a lower visual impact). Therefore, it is unclear whether these would be considered as first or second order expenditures. Consequently, the evaluation of the relation between distribution network costs and reliability is not straightforward. This is reflected in the fact that, whilst many studies about the cost of interruptions for consumers have been carried out over the years, there are much fewer studies on the reliability costs for distribution networks.

Conventionally, this problem has been addressed through engineering analyses that combine reliability and cost assessments. Several authors have analyzed the effects of different regulatory frameworks for continuity of supply on the optimal investment decisions of DSOs (Carvalho and Ferreira, 2005; Alvehag and Soder, 2011). The main drawback of these studies is that they do not explore the overall distribution cost function but a limited amount of investment or grid configuration alternatives. Therefore, the marginal cost at the optimal quality point, which is needed for regulation through linear incentives, is not obtained. This shortcoming has been addressed by other authors who perform more detailed analyses about the investment alternatives of DSOs and the effect of different parameters on the distribution reliability costs (Rivier, 1999; Ajodhia et al., 2005). However, in all these cases, only small test feeders could be analyzed. Hence, the results are very particular to the case study analyzed and it is unclear how to extrapolate the results to a system level.

It was not until very recently that more comprehensive studies quantifying the reliability driven distribution costs of large areas or at DSO level were published. In this regard, two approaches can be found. Some authors employ econometric analyses over data samples or actual distribution companies to estimate parametric cost functions that include the effect of a specific indicator of continuity of supply. On the other hand, other authors instead of using actual observations resort to the results of a norm model to obtain data with which they perform regressions.

Within the former category two publications have been found, (Jamasb et al., 2010) perform regressions over panel data for UK distribution utilities in the period 1995-2003 using the customer minutes lost (CML) as a variable. The authors estimate a marginal cost of improving quality in the range of 0-2.5 £/min (cost vs. CML) and conclude that despite the fact that incentive to improve continuity of supply in the UK have worked over the years, there is still significant room for further improvement. (Coelli et al., 2011) carry out a similar analysis in which they estimate a distribution cost function for 92 distribution units, corresponding to areas operated by the French DSO ERDF, using a panel of data for the period 2003-2005. In this case, the variable measuring continuity of supply is the yearly number of interruptions. Their result show marginal quality improvement costs in the range of 2.7-15.7€ per consumer interrupted, which are higher when reliability levels are closer to the 0% interruptions.

Only one work using the latter approach has been found. The authors in (Fernandes et al., 2012) analyzed three large-sized distribution areas, urban, semi-urban and rural; with the RNM used to regulate Spanish DSOs varying the requirements in terms of continuity of supply. This was done by multiplying the indices TIEPI/ASIDI and NIEPI/ASIFI the reference networks had to comply with by a K factor varying from 0.2 to 1.8 with a step of 0.05. The results obtained, pairs of distribution costs and TIEPI-NIEPI, were used to fit a Cobb-Douglas function (one for each area and reliability index) whose derivative is interpreted as the marginal costs of improving continuity of supply. The results yielded maximum marginal costs of up to 14000€/MWh for ASIDI and up to 45€/customer for ASIFI in the rural area. The maximum values obtained for the urban area were 2000€/MWh for ASIDI and around 40€/customer for the case of ASIFI.

Both approaches rely on econometrics, although in one case past actual information is used, whereas engineering approaches use as input data the results of engineering network planning models. Using real observations is much simpler than using norm models, which usually require extensive input data and computational resources. However, engineering approaches may find it easier to acknowledge for heterogeneity variables such as load density, orography and other environmental variables which may affect the costs of providing reliability. In order to account for this, the previous purely econometric approaches tend to include several environmental variables measuring, for instance, the density of consumers, the size of the distribution area, assets age or weather factors. It is noteworthy that conventional cost benchmarking studies tend to include fewer environmental variables, as shown by the reviews in (Jamasb and Pollitt, 2001; Agrell and Bogetoft, 2003).

Another advantage of using actual information is that they allow observing the real strategies adopted by DSOs to improve quality, identifying, for example, tradeoffs between OPEX and CAPEX solutions or the use of preventive maintenance actions (Jamasb et al., 2010). On the other hand, the results of norm models are largely influenced by their internal and potentially less flexible algorithms. Nevertheless, contrary to engineering models, purely econometric approaches are highly susceptible to the evolution of regulatory frameworks and incentives. Thus, changes in the design of the regulatory incentives can affect the observed distribution costs. Moreover, econometric approaches only focus on the part of the cost curve that is observable with the panel data used. Therefore, engineering models seem more suitable to estimate the whole cost curve and future trends.

Finally there is an issue that has not been solved in any of the previous publications. This is how to set consistent incentives for several reliability indices at the same time. This is important since most linear incentive schemes include a component associated with the frequency of the interruptions and another related to their duration. Any of the studies previously discussed, regressions were performed for just one reliability indicator; note that (Fernandes et al., 2012) perform separate regressions for ASIDI and ASIFI despite the fact that the RNM used takes both together into account. Even though this is not discussed in any of the papers, a high degree of multicollinearity is to be expected from different reliability indicators. Therefore, in case a joint regression were performed, the parameters associated with both indicators may not be significant. Future research would be necessary to address this issue.

7.3.2 Taking into account the conditions in different areas/DSOs

The previous section has clearly shown that the cost curves, which are the basis for the definition of incentive rates and reference values in continuity of supply incentive schemes, show large variations depending on several factors. The cost of interruptions for consumers varied according to the characteristics of the consumers themselves (type of consumer, country) and of the interruptions they experience (duration, time of day, notice time). On the other hand, the expenses required to improve quality levels essentially depend on the characteristics of the distribution area (e.g. load density) and grid configuration (e.g. underground/overhead). Consequently, the design of incentive mechanisms should take into account the conditions faced by each DSO or distribution area. However, considering all the previous factors may result too burdensome for regulators. Therefore, some simplifications are frequently made.

As explained in section 7.2.2.1.2, using properly designed non-linear incentive schemes removes the need to analyze the DSO cost curve as the DSO would directly internalize the overall social costs of quality. In this case it would only be necessary to perform an adequate segmentation of the demand sector and a detailed characterization of the interruptions experienced by each demand group. An example of this regulatory approach can be found in the Norwegian incentive scheme based on the computation of the cost of energy not supplied (CENS) which is described in (Kjolle et al., 2008; Kjolle et al., 2009; Growitsch et al., 2010). Note that the reference values should indeed be set separately for each DSO or distribution area. This is because, despite the fact that the value of continuity for consumers in different areas may be the same (all residential consumers would value quality at the same price), the variation in the costs of DSOs would cause the optimal level of quality in each area to differ. This can be done on the basis of historical information as in the Norwegian case (Growitsch et al., 2010).

However, it is more common to design continuity of supply incentives according to the type of distribution area (urban rural) neglecting the detailed characterization of demand. The usual criterion to classify different distribution zones is the population of towns and cities (CEER, 2012). In this case, regulators are implicitly assuming that similar distribution areas present the same mix of different types of consumers. Note that taking into account the characteristics of the distribution grid of each DSO is necessary when linear incentive schemes are implemented (section 7.2.2.1.1). The optimal incentive rate in a linear incentive may vary across different areas, even if it is assumed that the consumers' costs remain the same for all areas, since the location of the optimal level of quality will vary as a result of the different distribution cost curves. As a consequence, the marginal cost of improving quality at the optimal level of quality, i.e. the optimal level of the incentive, would also change.

In line with this, (Jamasb et al., 2010; Fernandes et al., 2012) suggest tailoring the incentive rates to improve quality in accordance with the marginal quality improvement costs of each DSO. (Fernandes et al., 2012) prove that the cost of improving quality differs from one area to another and that the Spanish incentive design relying on a single incentive rate for all areas, in spite of setting different reference values, is insufficient for DSOs to improve continuity in rural areas. In these cases, the DSO may rather have poor continuity levels and pay a penalty than invest to improve quality. Additionally, (Jamasb et al., 2010) estimate that increasing the current incentive rate used in the UK would provide significant gains in social welfare.

7.3.3 How optimal levels of quality evolve over time

The importance of estimating the consumers and DSO cost function and the different approaches to do it have been discussed in previous sections. An added difficulty for regulators is that these curves do not remain static. Over time, the perception of consumers on the importance of reliability or the direct costs arising from interruptions can vary. Similarly, technology costs can vary due to market maturity of new technological developments. These issues will be discussed in more detail in section 7.4 for the particular case of smart distribution grids.

The main consequence for regulation of the shifts in both cost function lies in the fact that the optimal level of quality, and thus the associated optimal incentive rates, will change over time. The final position of the optimal level of quality would depend on the direction and the magnitude of the changes experienced by both curves. As shown in Figure 7-8, the optimal level of quality would tend to increase when the cost for consumers or their WTP increases as well as when the marginal costs of DSOs decrease. On the contrary, the socially optimal level of quality would decrease if marginal distribution costs increased or the consumers' WTP or costs decreased.

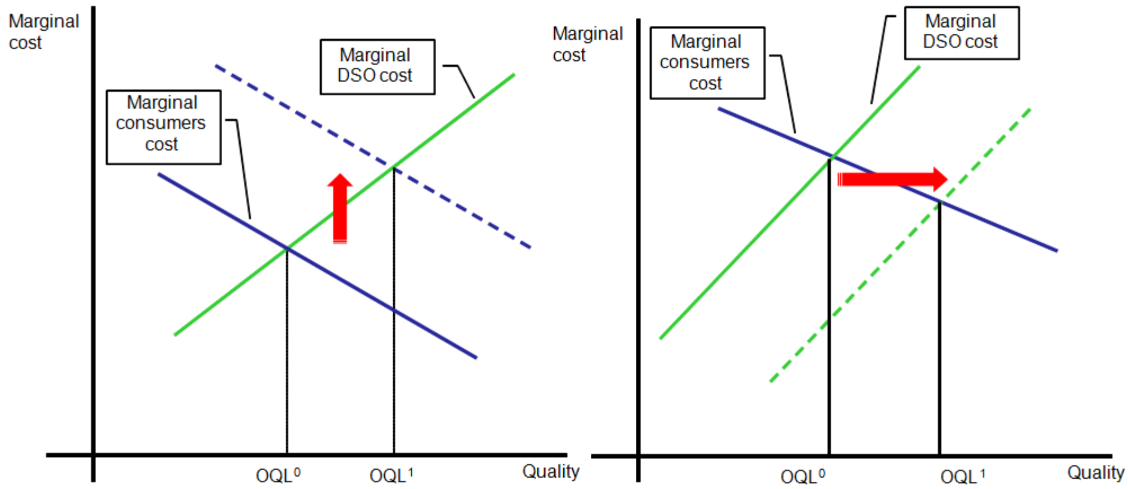

Figure 7-8: Evolution of the optimal level of quality: shift in the cost for consumers (left) and shift in the cost of DSOs (right)

7.3.4 Dealing with uncertainty and stochastic effects

Due to the limited knowledge of the aforementioned cost functions, regulators usually implement additional mechanisms that prevent large revenue deviations driven by wrong estimations of quality costs. These essentially consist in setting a cap and floor on the overall incentive/penalty received by the DSO expressed as a percentage on overall DSO revenues. Among the countries that set these limits one may find the UK, Italy, The Netherlands, Spain and Portugal (Fumagalli et al., 2007; Cossent et al., 2011b). This limit is generally set between 3% and 10% of allowed revenues and, except for the case of Italy, the cap and floor are symmetrical.

On the other hand, small variations can occur due to stochastic issues such as weather conditions. In order to mitigate the regulatory burden driven by these small variations, deadbands can be used. Thus, as long as the variation observed in the reliability indices do not fall outside a certain interval around the reference value, DSO revenues do not change (Ajodhia, 2005; Fumagalli et al., 2007). This is the case in countries such as Finland, Hungary, Ireland, Portugal and Slovenia (CEER, 2012). Similarly, some regulators take as measured values the average across several years, typically two or three years, in order to mitigate annual variations. This is done, for instance, in Italy and in Spain (AEEG, 2011; Cossent et al., 2011b).

7.3.5 Load based versus customer based indicators

Linear bonus-malus incentives are conventionally dependant on the values measured for different reliability indices. These values are generally computed according to the information provided by the firms, which at the same time ought to be audited to prevent measurement and accuracy errors (Fumagalli et al., 2007). The indices most commonly monitored are either consumer-based (SAIDI, SAIFI) or load-based (ASIDI, ASIFI). More specifically, consumer-based reliability indices are much more widely used in Europe (CEER, 2012). The main advantage of consumer-based indices is that they are easier to compute since they do not require defining a fixed load capacity. This is relevant as in several countries, consumers are charged according to the maximum consumption over a certain period of time, e.g. monthly. Nonetheless, it is being implicitly assumed that all consumers are heterogeneous. Therefore, the presence of some large consumers who are most significantly affected by interruptions is not taken into account (McDermott and Dugan, 2003).

Load-based indices may indeed overcome this drawback. However, as mentioned above, it is not straightforward to define the capacity considered to compute the indices. Several alternatives exist, comprising the capacity contracted by consumers (maximum instantaneous consumption allowed), the average capacity consumed (measured as the annual energy consumption over the 8760 hours per year) or the MV/LV installed capacity. Using the average consumption or the transformation capacity is simpler and can be implemented even when consumers do not contract a fixed capacity. However, average consumption may lead to variations in the reliability indices measured caused by demand variations driven by weather, economic context, demand response programmes or DG, instead of by actual variations in the network reliability levels.

Moreover, using the MV/LV transformation capacity would neglect the interruptions occurred at LV level since these do not affect this power. Additionally, investment decisions of DSOs can also influence the measured reliability. In principle, increasing the transformation capacity in those areas with higher reliability (e.g. shorter feeders), ceteris paribus, would result in better reliability indices (although not better actual reliability levels). Notwithstanding, the latter effect would not presumably be relevant in practice as under normal conditions DSOs would not upgrade transformer substations except in case relevant changes in demand occur.

Therefore, using some kind of contracted capacity seems to be the most appropriate as it correspond to a fixed value that appropriately represents how end consumers are affected by interruptions. However, it is more complex to use as compared to the previous alternatives as this requires more detailed connectivity models and interruption recording methods (which are equally required to implement customer-based indices). Additionally, it is arguable whether introducing the concept of contracted capacity is justified only for the regulation of continuity of supply in those countries where consumers pay only volumetric charges or pay a capacity charge in accordance to the maximum consumption recorded.

7.3.6 Setting the reference quality level and its relation with overall DSO revenues and regulatory asset base

Up to this point, the incentives aiming to improve continuity of supply have been discussed as a separate issue from the overall revenue determination. However, there is a very important relation between how the reference value for quality levels is determined and updated, the DSO allowed revenues and the strength of the incentives perceived by DSOs to invest in quality improvements.

A question that is not often addressed explicitly is whether the regulatory incentives should be enough by themselves to attract expenditures in quality improvements or whether they should serve merely as a complement to the allowed revenue determination so as to prevent quality deterioration. The theoretical framework previously presented assumes that the regulatory incentives, determined separately from the revenue determination process, are sufficient to recoup all the quality driven costs. Nonetheless, it will be shown that it may be needed to reopen this question.

The former approach would imply that incremental investments should be fully recovered before the reference value for quality is updated, usually at the end of each regulatory period. However, this in unlikely to happen in case continuity improvements are to be achieved through CAPEX which show recovery times longer than one year or even longer than a regulatory period. Under these circumstances, the time horizon considered when making investment decisions is not the useful life of assets, but the time between reference value updates (affecting the distribution cost function previously considered). Moreover, there can be a lag between the point when investment decisions are made and carried out and the point when the actual effects on continuity of supply can be observed. Therefore, this regulatory approach may deter DSOs from investing in quality improvements, especially when reference values are updated frequently.

Consequently, several authors advocate for the implementation of a quality-integrated cost benchmarking to define DSO allowed revenues (Ajodhia, 2005; Giannakis et al., 2005; Yu et al., 2007). Being this the case, quality driven investments can be, at least partly, included in the asset base and yearly allowed revenues. Thus, the continuity incentives do not need to be sufficient to cover all the quality driven investments, but to encourage DSOs to prioritize and carry out these investments and prevent quality deterioration.

Reference values would be defined in accordance with the allowed revenues, being it possible to set individually for each DSO, when there is a large heterogeneity across DSOs, or common for all DSOs serving the same type of distribution areas (classified, for instance, according to load concentration). This is usually done by using historical information and demanding a certain improvement over time. Furthermore, these reference values should remain constant for several years, for instance for a whole regulatory period, in order not to dilute the power of these incentives.

7.4 Smart grid technologies and the computation of continuity of supply incentives

As introduced in section 7.3.3 smart grid technologies will affect the cost curves that should be considered when setting regulatory incentives to improve continuity of supply. This section will go deeper into this analysis, focusing specifically on the effects of technological developments. Section 7.4.1 presents a study on the effects of new network technologies on the achievable continuity improvements and the costs involved. Simple case studies will be used to illustrate the concepts discussed. On the other hand, section 7.4.2 will assess the implications of a large-scale deployment of smart meters at residential level in terms of continuity of supply monitoring and regulation.

7.4.1 Smart grids, marginal quality improvement costs and optimal continuity of supply levels

Residential consumers may present increasing levels of WTP as a result of a stronger dependence upon a reliable electricity supply arising from the use of more digital technologies or, in the coming future, electric vehicles. Similarly, some industries may shift the use of other energy sources for electricity, such as metallurgical ovens, thus worsening the consequences of interruptions for them. On the other hand, the effects of the economic recession may cause a decrease in the consumers' WTP. Furthermore, the already high levels of continuity of supply offered in many countries may cause consumers to perceive a lower value of increasing continuity levels (lower WTP), although the negative effects of an interruption will be deemed more important (higher WTA). Overall, the net effect will presumably be that consumers will be affected more deeply thus shifting the optimal quality level upwards. Moreover, as it will be discussed in section 7.5, the potential inclusion of DG as additional network users can increase the importance of reliability in distribution networks.

However, the most important changes and main uncertainties are related to the performance and costs of the smart grid technologies and solutions. In (Ajhodia, 2005), the author mentions that as DSOs become more efficient, the marginal cost of improving quality will decrease over time. Moreover, technological developments may also shift the distribution cost function. On the one hand, existing technologies can see their costs reduced as a result of new developments and market maturity. Nonetheless, these potential gains could be rather limited for conventional technologies and operational practices as suggested by the fact that continuity of supply improvements in many European countries tend to stagnate over time (CEER, 2012). Therefore, achieving smarter distribution grids seems to be the way forward to attain higher levels of continuity of supply, should this be cost-effective for consumers[45].The penetration of smart grid technologies can imply a significant change in the strategies and costs involved in improving quality of service.

Whilst it is true that these new technologies tend to be more expensive than conventional technologies, two factors should be considered when assessing the reliability driven distribution costs under the smart grid paradigm. Firstly, conventional technologies may present a limit in the level of continuity of supply that is achievable, at least without incurring in additional first order investments. This limit may be pushed forward with the introduction of new equipment (fault detectors, telecontrolled switchers) or software and operational strategies (outage management system-OMS, intentional islanding). Secondly, smart grid technologies, despite presenting higher unitary costs, may also bring about a greater quality improvement per monetary unit spent. Therefore, this could drive marginal quality costs down.

[45] Installing new substations and modifying the grid topology is another alternative that will enhance continuity of supply. However, this involves very high costs that would probably not be justified in terms of quality improvement exclusively.

In order to find answers for these questions, the next subsections will analyze the effect on several continuity indicators of different investment alternatives for two test feeders, comprising both conventional and innovative solutions. Further details about the results obtained are provided in annex D.

7.4.1.1 Smart grid technologies in a rural test feeder

The rural overhead MV feeder shown in Figure 7-9 will be analyzed. It can be seen that consumers, both in number and demand, are evenly distributed along the feeder.

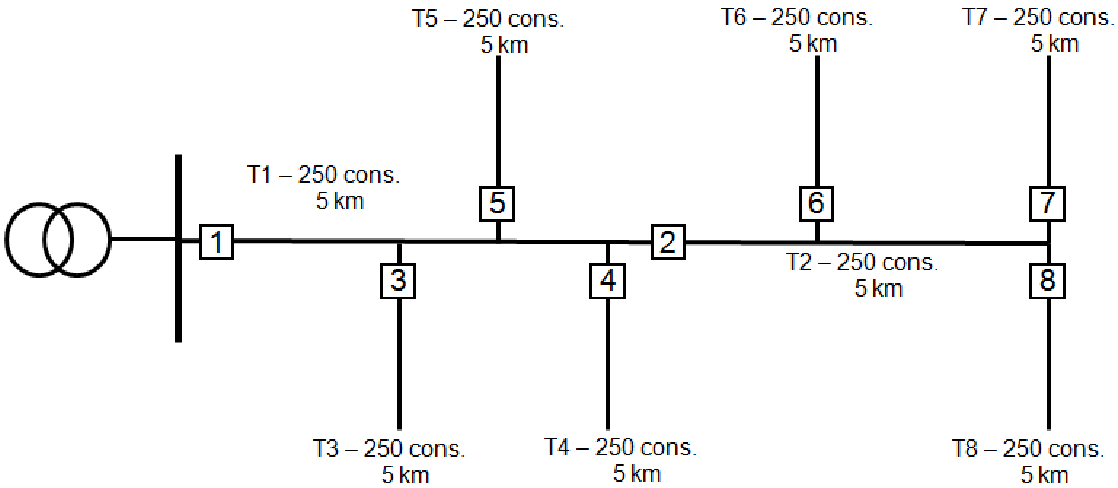

Figure 7-9: Test rural MV feeder (overhead lines). Adapted from (McDermott and Dugan, 2003)

The methodology is based on evaluating several reliability indices (SAIDI, SAIFI, ASIDI and ASIFI (IEEE, 2001)) attained in the previous test feeder under different configurations. Each feeder configuration is characterized by the installation of different control and protection devices in the locations numbered 1-8 in Figure 7-9. The devices considered and their approximate costs are shown in Table 7-2. The annualized investment costs have been computed with a 7% discount rate and a useful life of 10 years. The annual cost for fuses is computed according to the number of times per year they would have to be replaced. The costs below are in line with previous publications carrying out similar studies (Fumagalli et al., 2004; Skala et al., 2009). Investment alternatives are limited to some protection and control devices (short-term focus). Hence, other options such as alternative points of supply (Chowdhury and Koval, 2004) or changing the type of conductor (Alvehag and Soder, 2011) will not be considered for this test feeder.

Devices	Unit investment cost	Annual O&M cost	Annuity Inv.+O&M
Breaker	3.000 €	300 €	727 €
Fuse	600 €	0 €	Replacement
Recloser	15.000 €	500 €	2.636 €
Fault detector	1.000 €	50 €	192 €
Telecontrolled breaker	10.000 €	300 €	1.724 €
Telecontrolled recloser	20.000 €	500 €	3.348 €

Table 7-2: Technologies and costs for reliability analysis in rural feeder

The previous devices may reduce the number of interruptions or the area affected by an interruption. Moreover, they may lower the time required to locate and repair the faults and restore the power supply. Fuses and breakers isolate the corresponding faulted feeder sections for any fault, whereas reclosers trip only under permanent fault conditions. The implementation of telecontrol functions on these devices significantly reduces restoration times (assumed to act instantaneously). Finally, fault detectors allow DSOs to reduce fault location times. This reduction depends on the configuration of the feeder, i.e. how fault detectors divide the feeder into segments. Breakers and fuses can be considered as conventional technologies. On the other hand, reclosers and fault detectors are relatively newer technologies that are not so widespread. Finally, telecontrolled devices can be considered as smart grid technologies.

In this line, the feeder configurations analyzed have been divided into three groups or clusters, depending on the technologies available to DSOs over time (it is assumed that older technologies would always be available to DSOs). Configurations with higher costs than others which perform better have been neglected. For instance, protections in lateral branches would be placed in sections T3-5 before doing it in sections T6-8 since interruptions in these laterals would affect consumers in the second half of the feeder too. Similarly, given that momentary interruptions and voltage sags are not considered, because regulatory incentives in Europe rarely consider these interruptions (CEER, 2012), installing reclosers in series would not yield any benefits in terms of reliability. In total, the 40 configurations summarized in Table 7-3 have been analyzed.

	Configuration number	Device at each location							
		1	2	3	4	5	6	7	8
Technology cluster 1	1	B	-	-	-	-	-	-	-
	2	B	B	-	-	-	-	-	-
	3	B	B	F	-	-	-	-	-
	4	B	B	F	F	-	-	-	-
	5	B	B	F	F	F	-	-	-
	6	B	B	F	F	F	F	-	-
	7	B	B	F	F	F	F	F	-
	8	B	B	F	F	F	F	F	F
Technology cluster 2	9	R	-	-	-	-	-	-	-
	10	R	B	-	-	-	-	-	-
	11	R	B	F	-	-	-	-	-
	12	R	B	F	F	-	-	-	-
	13	R	B	F	F	F	-	-	-
	14	R	B	F	F	F	F	-	-
	15	R	B	F	F	F	F	F	-
	16	R	B	F	F	F	F	F	F
	17	R	F	-	-	-	-	-	-
	18	R	-	F	F	F	F	F	F
	19	B	FD	-	-	-	-	-	-
	20	R	FD						
	21	B	B	FD	FD	FD	FD	FD	FD
	22	R	B	FD	FD	FD	FD	FD	FD
	23	B	B/FD	-	-	-	-	-	-
	24	R	B/FD						
	25	B	B	F/FD	F/FD	F/FD	F/FD	F/FD	F/FD
	26	R	B	F/FD	F/FD	F/FD	F/FD	F/FD	F/FD
Technology cluster 3	27	TCB	-	-	-	-	-	-	-
	28	TCB	B	-	-	-	-	-	-
	29	TCB	B	F	F	F	-	-	-
	30	TCB	B	F	F	F	F	F	F
	31	TCB	TCB	-	-	-	-	-	-
	32	TCB	TCB	F	F	F	-	-	-
	33	TCB	TCB	F	F	F	F	F	F
	34	TCR	-	-	-	-	-	-	-
	35	TCR	B	-	-	-	-	-	-
	36	TCR	B	F	F	F	-	-	-
	37	TCR	B	F	F	F	F	F	F
	38	TCR	TCB	-	-	-	-	-	-
	39	TCR	TCB	F	F	F	-	-	-
	40	TCR	TCB	F	F	F	F	F	F

Table 7-3: Feeder configurations analyzed for the rural feeder (B-Breaker; F-Fuse; R-Recloser; FD-Fault detector; TCB-Telecontrolled breaker; TCR-Telecontrolled recloser)

Since the purpose of this analysis is merely to illustrate the potential impact of smart grid technologies, a simple deterministic method for reliability evaluation has been used. Following (McDermott and Dugan, 2003) several assumptions are made. Fuse saving and appropriate protections coordination is assumed to be achieved for all faults. Deterministic failure rates will be considered. Failure rates of conductors are assumed to be much higher than those of protection devices and the upstream grid, thus being possible to neglect the latter. Simultaneous failures in two branches will not be considered. Repair times are the same for all sections. Nonetheless, fault location and restoration times, as well as failure rates, are higher for lateral branches. The input data considered are shown in Table 7-4.

Failure rate [fault/km-year]	Trunk	0,15
	Lateral	0,2
Length of section [km]		5
Share of temporary faults		80%
Fault location time [h]	Trunk	1
	Lateral	2
Fault repar time [h]		1,5
Restoration time [h]	Trunk	0,5
	Lateral	0,75
Number of consumers per section		250
Average peak power [kW/cons.]		2,5

Table 7-4: Input data for reliability analysis in rural feeder

In order to present the results graphically, a customer damage function has been constructed by multiplying the SAIDI and SAIFI indices[46] by two parameters that convert them to monetary units, as shown in (7-5). The main objective is to incorporate into a single index both the number and duration of interruptions, which previous analyses have neglected when building similar curves (Jamasb et al., 2010; Coelli et al., 2011; Fernandes et al., 2012). The numerical values for the α and β parameters, 0.1325€/kW-int. and 1.17 €/kWh respectively, have been taken from a survey carried out among residential consumers in Norway (Kjolle et al., 2009)[47]. In a more detailed approach the time when each interruption occurs and the type of consumers (residential, commercial, industrial, etc.) connected to the distribution network should be considered.

$$Cost_{\text{int}} = P_{dem} \cdot \left(\alpha \cdot SAIFI + \beta \cdot SAIDI \right) \qquad (7\text{-}5)$$

Where:

$Cost_{int}$	Cost of interruptions for consumers [€]
α	SAIFI parameter [€/kW-interruption][48]
β	SAIDI parameter [€/kWh]
P_{dem}	Total power demanded [kW]

The results obtained are depicted in Figure 7-10, which shows the annualized costs incurred by the DSO versus the cost of interruptions for consumers under the 40 feeder configuration evaluated. The three technological clusters considered have been differentiated. These results prove that under different feeder configurations, reliability levels can vary significantly. Moreover, the maximum feasible levels of quality increase as new technologies are available to DSOs. In this case, the maximum reliability level achievable with cluster 1 (cost of interruptions around 40k€) is much lower than that in cluster 2 (cost of interruptions around 7.5k€), whereas for cluster 3 the maximum level (cost of interruptions around 7.3k€) is slightly higher than in stage 2. Nonetheless, the difference between the two last technology clusters is very small; in fact, this is almost unobservable in Figure 7-10.

[46] Since load is evenly distributed across all feeder sections, these indices are same as ASIDI and ASIFI for this case study

[47] Exchange rate used 1€ = 7.55 NOK (June 2012)

[48] The α and β parameters may seem not to have consistent units as they dare expressed in units of power and the SAIDI and SAIFI indices are customer-based. Nonetheless, unit consistency is ensured by multiplying the resulting quantities by the total contracted/installed power in the distribution network.

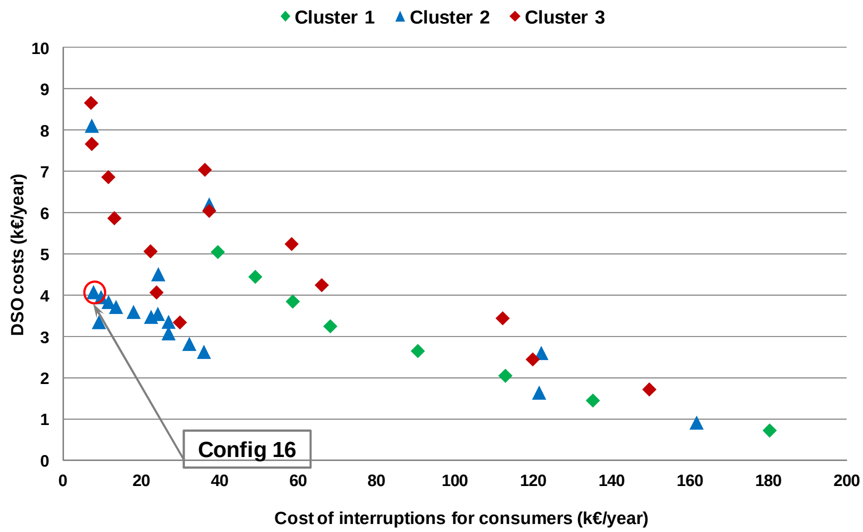

Figure 7-10: Annualized DSO costs versus interruption costs under different configurations of the rural feeder

Additionally, results show that more cost-effective solutions, having lower marginal cost of quality improvement, can arise over time. For example, the introduction of reclosers in the second cluster allowed significant reduction in the number and duration of interruptions at reduced costs. This can be clearly observed in the bottom left part of Figure 7-10, where many recloser-based configurations are located. However, this does not necessarily happen with all technologies. In this case, the implementation of telecontrol functions does not yield cost-effective quality improvements.

Finally, the results obtained also denote that the socially optimal level of quality, where the sum of the costs incurred by DSOs and consumers is minimized, can change due to technological developments. If only technologies in cluster 1 are considered, configuration 8 would yield the optimal level of quality. However, the optimal level shifts to configuration 16 (highlighted in Figure 7-10) when the all the technology clusters are considered, which results in a 73% reduction in total social costs as compared to configuration 8.

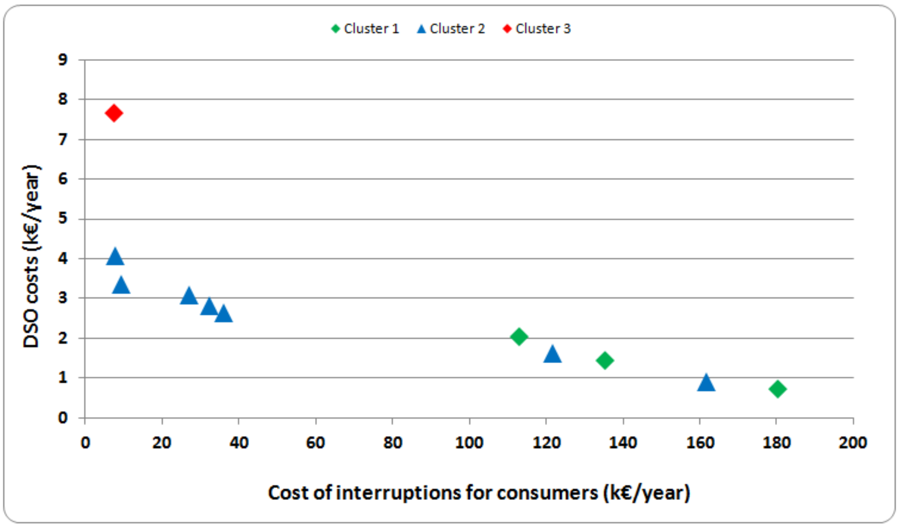

Figure 7-11: Annualized DSO costs versus interruption costs under different configurations of the rural feeder for the non-dominated configurations

The 40 configurations Table 7-3 have been studied and included in Figure 7-10. Nevertheless, some of these correspond to dominated solutions. Hence, it is possible to find another configuration with lower costs and better reliability. Only 11 of these 40 configurations are not dominated: 1, 2, 3, 9, 16, 17, 18, 19, 20, 23 and 37. The Pareto front of the problem is represented in Figure 7-11. It can be seen that the slope of the front increases sharply for the highest reliability level owing to the high costs of telecontrolled devices. The gap observed between the points for clusters 1 and 2 is caused by the significant quality improvement caused by the installation of reclosers in overhead feeders where temporary faults are very frequent.

7.4.1.2 Smart grid technologies in a urban test feeder

The results obtained for the previous case study are largely influenced by the type of feeder analyzed. Rural overhead feeders, contrary to urban underground feeders, present a high share of temporary faults. Consequently, reclosers, despite being more costly than conventional breakers, present lower marginal reliability improvement costs. On the contrary, fault detectors show scarce benefits, except for scenarios with very poor quality levels. These devices could potentially be more beneficial in underground networks where fault location and isolation times account for a high share of the total interruption duration. Similarly, telecontrolled devices would allow much faster fault isolation in urban networks, thus limiting the area affected by an interruption, thanks to the grid being meshed. Therefore, the effects of smart grid technologies can differ across different distribution networks. In order to illustrate these differences, the urban MV feeder shown in Figure 7-12 has been analyzed too.

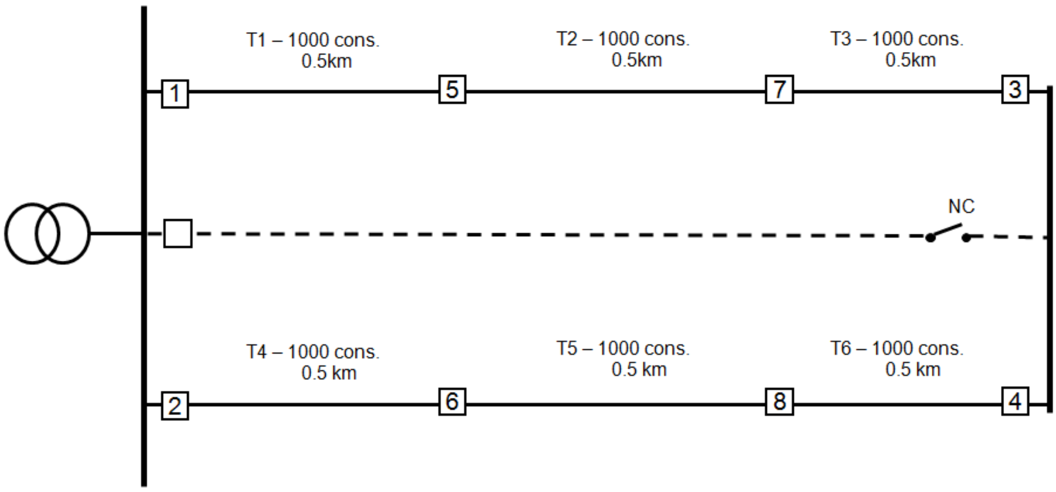

Figure 7-12: Test urban MV feeder (underground lines)

Similarly to the previous case study, consumers are evenly distributed, both in number and demand, across the feeder. As compared to the previous case study, the urban network is built completely underground and presents shorter feeders with a higher load concentration. This simplified urban feeder shows a meshed configuration by which the back-up emergency feeder provides an auxiliary path to supply part of the loads located in the two main MV feeders when a fault occurs in any of them. In order to achieve this, normally open (NO) switching devices are placed in locations 3 and 4, whereas a normally closed (NC) switch would be installed at the end of the back-up feeder. The capacity of the back-up feeder is assumed to be enough to supply the entire load of the non-faulted sections and breakers are assumed to incorporate switching capabilities.

The same methodology previously described will be followed for this case study. The reliability indices that would result under different feeder configurations will be computed. Each configuration is defined by the installation of different control and protection devices in the locations numbered 1-8 in Figure 7-12. The devices considered in this case are slightly different, due to the distinct features of urban distribution grids. Since the distribution network analyzed now is entirely underground, all faults will be considered to be permanent. Therefore, the installation of reclosers is not considered. Instead, switching operations to reconfigure the grid become much more relevant thanks to the meshed structure of the feeder. Moreover, a new device which aims at detecting possible deterioration in the cable insulation so as to prevent faults is included. All the devices considered are shown in Table 7-5 together with their approximate yearly costs (7% discount rate and useful life of 10 years).

Devices	Unit investment cost	Annual O&M cost	Annuity Inv.+O&M
Breaker	3000	300	727,13 €
Switch	900	100	228,14 €
Partial discharge detector	8000	500	1.639,02 €
Directional fault detector	1000	50	192,38 €
Telecontrolled breaker	10000	300	1.723,78 €
Telecontrolled switch	7000	200	1.196,64 €

Table 7-5: Technologies and costs for reliability analysis in urban feeder

Breakers and switches allow isolating the fault and reconfiguring the distribution network to minimize the number of consumers affected by an interruption. Switches cannot open the circuit under fault conditions, but may operate on normal loading conditions. Therefore, breakers trip after a fault and the maintenance crew could operate the downstream switches to isolate the fault and reduce the length of the interruption suffered by some consumers. Those consumers located in the faulted feeder section would have to wait for the fault to be repaired, whereas the consumers in other feeder sections separated by switches would only experience an interruption whose length coincides with the time required to isolate the fault. Estimating the number of switching operations is essential as this will determine the interruption time for consumers outside the faulted feeder sections. In order to illustrate the assumptions made for this analysis, let us consider a feeder with three sections as shown in Figure 7-13.

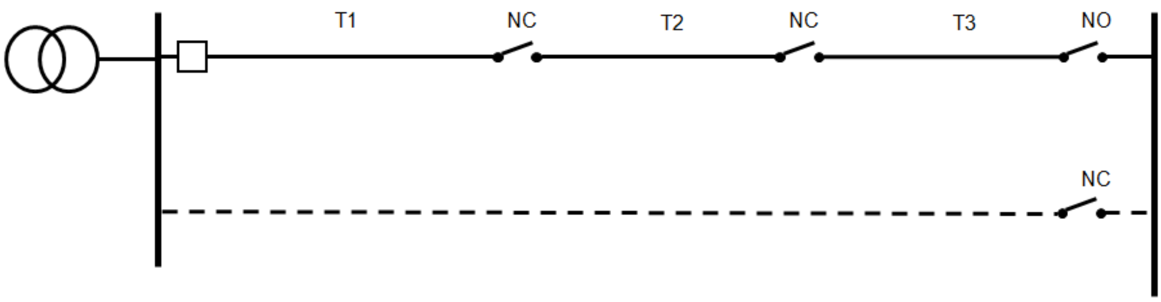

Figure 7-13: Example of switching operations in urban MV feeder

The breaker at the feeder header will automatically trip for any fault in the feeder. If this fault has occurred in the section T1, the maintenance crew would open the NC switch between sections T1 and T2 and close the NO switch located at the end of the feeder. Thus, the load in sections T2 and T3 can be restored without waiting for the cable to be repaired. On the other hand, if the fault has occur in T2, it will be assumed that the crew would first restore power supply to the loads in T1 by opening the NC between T1 and T2 and then rearm the breaker at the head of the feeder (two switching operations). Subsequently, the maintenance crew would restore the supply to T3 by opening the NC switch between T2 and T3 and then closing the NO switch at the end of the feeder (two additional switching operations). Lastly, when the fault occurs in T3, power supply will be restored to T1 and T2 by opening the NC switch separating T2 and T3 and rearming the breaker.

Regarding the remaining devices, partial discharge detectors allow DSOs to monitor the state of the underground cable insulation so as to prevent interruptions by means of preventive maintenance. Thus, for this analysis it will be assumed that installing partial discharge detectors in the feeder under study reduces the fault rates of the cables as this preventive maintenance actions would cause only planned interruptions. The range of these devices is assumed to be of 500m where a 20% reduction in fault rates is achieved. The fault detector reduces fault location times when the fault is located in the same branch as the fault detector, according to the segmentation of the feeder. Lastly, telecontrolling breakers and switches lower the time taken to perform switching operations (assumed to act instantaneously).

As done for the rural feeder, these devices have been classified into three technology clusters. Breaker and switches belong to the first cluster of conventional technologies; partial discharge monitoring and fault detectors are added to form the second cluster, whereas telecontrolled devices are only present in the third and last cluster of smart grid technologies. Accordingly, the feeder configurations analyzed have been categorized in three groups. As done in the previous analysis, high-cost configurations showing a poor reliability have not been considered. Moreover, short interruptions were not taken into account. A total of 75 configurations have been analyzed. These are shown in Table 7-6.

	Configuration number	Device at each location							
		1	2	3	4	5	6	7	8
Technology cluster 1	1	B	B	S	S	-	-	-	-
	2	B	B	S	S	S	-	-	-
	3	B	B	S	S	S	S	-	-
	4	B	B	S	S	S	S	S	-
	5	B	B	S	S	S	S	S	S
	6	B	B	S	S	B	-	-	-
	7	B	B	S	S	B	B	-	-
	8	B	B	S	S	B	B	B	-
	9	B	B	S	S	B	B	B	B
	10	B	B	S	S	B	S	-	-
	11	B	B	S	S	B	S	S	-
	12	B	B	S	S	B	S	S	S
	13	B	B	S	S	B	B	S	-
	14	B	B	S	S	B	B	S	S
	15	B	B	S	S	B	B	B	S
Technology cluater 2	16	B	B	S	S	FD	-	-	-
	17	B	B	S	S	FD	FD	-	-
	18	B	B	S	S	FD	FD	FD	-
	19	B	B	S	S	FD	FD	FD	FD
	20	B	B	S	S	S/FD	-	-	-
	21	B	B	S	S	S/FD	S/FD	-	-
	22	B	B	S	S	S/FD	S/FD	S/FD	-
	23	B	B	S	S	S/FD	S/FD	S/FD	S/FD
	24	B	B	S	S	B	B	FD	-
	25	B	B	S	S	B	B	FD	FD
	26	B	B	S	S	B	B	S/FD	-
	27	B	B	S	S	B	B	S/FD	S/FD
	28	B/PD	B	S	S	-	-	-	-
	29	B/PD	B/PD	S	S	-	-	-	-
	30	B/PD	B/PD	S	S	PD	-	-	-
	31	B/PD	B/PD	S	S	PD	PD	-	-
	32	B/PD	B/PD	S	S	PD	PD	PD	-
	33	B/PD	B/PD	S	S	PD	PD	PD	PD
	34	B	B	S	S	S/PD	-	-	-
	35	B	B	S	S	S/PD	S/PD	-	-
	36	B	B	S	S	S/PD	-	PD	-
	37	B	B	S	S	S/PD	S/PD	PD	PD
	38	B	B	S	S	B	-	PD	-
	39	B	B	S	S	B	B	PD	PD
	40	B	B	S	S	FD	-	PD	-
	41	B	B	S	S	FD	FD	PD	PD
	42	B	B	S	S	S/FD	S/FD	PD	PD
	43	B	B	S	S	S/FD	S/FD	S/PD	S/PD
	44	B	B	S	S	S/PD	S/PD	S	S
	45	B	B	S	S	S/FD	S/FD	S	S
Technology cluster 3	46	B	B	S	S	TCS	S	S	S
	47	B	B	S	S	TCS	TCS	S	S
	48	B	B	TCS	S	S	S	S	S
	49	B	B	TCS	TCS	S	S	S	S
	50	TCB	B	S	S	S	S	S	S
	51	TCB	TCB	S	S	S	S	S	S
	52	B	B	S	S	TCS	TCS	TCS	S
	53	B	B	S	S	TCS	TCS	TCS	TCS
	54	TCB	B	S	S	TCS	TCS	TCS	TCS
	55	TCB	TCB	S	S	TCS	TCS	TCS	TCS
	56	TCB	TCB	TCS	S	TCS	TCS	TCS	TCS
	57	TCB	TCB	TCS	TCS	TCS	TCS	TCS	TCS
	58	TCB	TCB	S	S	TCB	TCB	S	S
	59	TCB	TCB	S	S	TCB	TCB	TCS	TCS
	60	TCB	TCB	S	S	TCB	TCB	TCB	TCB
	61	TCB	TCB	TCS	TCS	TCB	TCB	TCB	TCB
	62	B	B	S	S	TCS/FD	TCS/FD	S/FD	S/FD
	63	TCB	TCB	S	S	S/FD	S/FD	S/FD	S/FD
	64	TCB	TCB	S	S	TCS/FD	TCS/FD	S/FD	S/FD
	65	B	B	S	S	TCB	TCB	S/FD	S/FD
	66	TCB	TCB	S	S	B	B	S/FD	S/FD
	67	B	B	S	S	TCB	TCB	TCS/FD	TCS/FD
	68	B	B	S	S	TCS/FD	TCS/FD	S	S
	69	B	B	S	S	TCS/FD	TCS/FD	TCS	TCS
	70	B	B	TCS	TCS	TCS/FD	TCS/FD	S	S
	71	B	B	S	S	TCS/FD	TCS/FD	S/PD	S/PD
	72	B	B	S	S	TCS/FD	TCS/FD	TCS/PD	TCS/PD
	73	B	B	S	S	TCB	TCB	PD	PD
	74	B	B	S	S	TCB	TCB	TCS/PD	TCS/PD
	75	B	B	S	S	B	B	TCS/PD	TCS/PD

Table 7-6: Feeder configurations analyzed for the urban feeder (B-Breaker; S-Switch; PD-Partial discharge detector; FD-Fault detector; TCB-Telecontrolled breaker; TCS-Telecontrolled switch)

The same deterministic reliability analysis drawn from (McDermott and Dugan, 2003) has been carried out for each feeder configuration. Appropriate protections coordination is assumed for all faults. Deterministic failure rates will be considered. Failure rates of conductors are assumed to be much higher than those of protection devices and the upstream network and simultaneous failures have been neglected. Repair times are the same for all sections. Nonetheless, fault location and restoration times, as well as failure rates, depend on the feeder sections and its configuration. The time of interruptions considered to compute the reliability indices does not include the time required to go back to the original network configuration as it is assumed that no further interruptions arise from this reconfiguration. The main input data used are shown in Table 7-7.

Failure rate [fault/km-year]	0,075
Length of each section [km]	0,5
Fault location time [h]	8
Fault repar time [h]	15
Switching operation time [h]	0,75
Number of consumers per section	1000
Average peak capacity [kW/cons.]	2,5

Table 7-7: Input data for reliability analysis in urban feeder

In order to quantify a single indicator of reliability, the formula in equation (7-5) has been used. The same values of the equation parameters applied to the previous case study have been considered herein. The results obtained for the urban feeder show that overall the reliability indices obtained tend to be much lower as compared to the rural one. This is to be expected due to the meshed structure of the network and the lower fault rates of underground cables. Nonetheless, several similarities can be observed as well. Figure 7-14 represents the annualized costs incurred by the DSO versus the cost of interruptions for consumers corresponding to the 75 feeder configurations evaluated. The three distinct technological clusters have been differentiated. The results show that the maximum feasible level of quality, measured through the cost of interruptions for consumers, improves thanks to the penetration of new technologies (22.0k€ for cluster 1, 18.1k€ for cluster 2, and 16.5k€ for cluster 3).

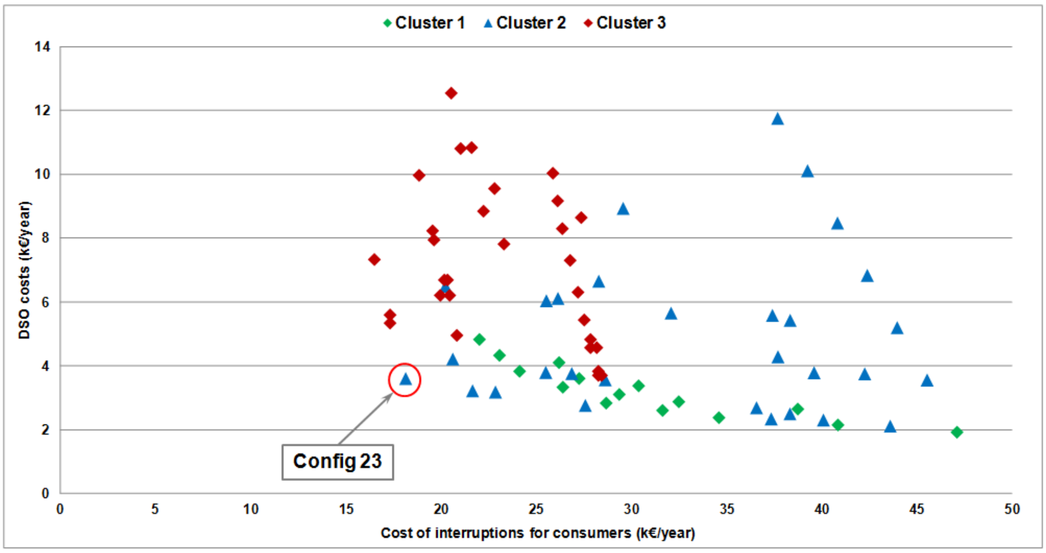

Figure 7-14: Annualized DSO costs versus interruption costs under different configurations of the urban feeder

Furthermore, the progressive introduction of new technologies brings about solutions showing a lower marginal cost of quality improvement. In this case, fault detectors allow attaining better solutions than when only breakers and switches were used given the amount of time required to locate a fault in underground grids. Partial fault detectors yield more limited reliability gains (under the assumptions made) due to the low fault rates considered for underground cables. In Figure 7-14, many of the configurations characterized by the installation of partial discharge detectors correspond to the blue triangles in the upper right part of the chart, thus being dominated solutions. Nevertheless, these devices could be more profitable in aged networks where failure rates are higher, although cost reductions (or increasing the operating range of these devices) may still be required.

Moreover, similarly to the rural feeder, the implementation of telecontrol functions does not yield cost-effective quality improvements in spite of attaining higher reliability levels. Notwithstanding, telecontrol functions are clearly more effective in this feeder than in the rural one. A 50% reduction in the investment costs of telecontrolled devices, which may be achieved if the communication network is used for other smart grid applications as well, would result in configuration 64 being the optimal one. The results obtained under these conditions are plotted in Figure 7-15. On the other hand, if the time required to perform a switching operation increased from 0.75h to 1.78h, the optimal feeder configuration would be configuration 62. Additionally, it must be born in mind that the feeder analyzed is a very simple one, where service restoration involves a very low number of switching operations. In more intensely meshed feeders, telecontrolling the sectionalizing devices may yield higher benefits.

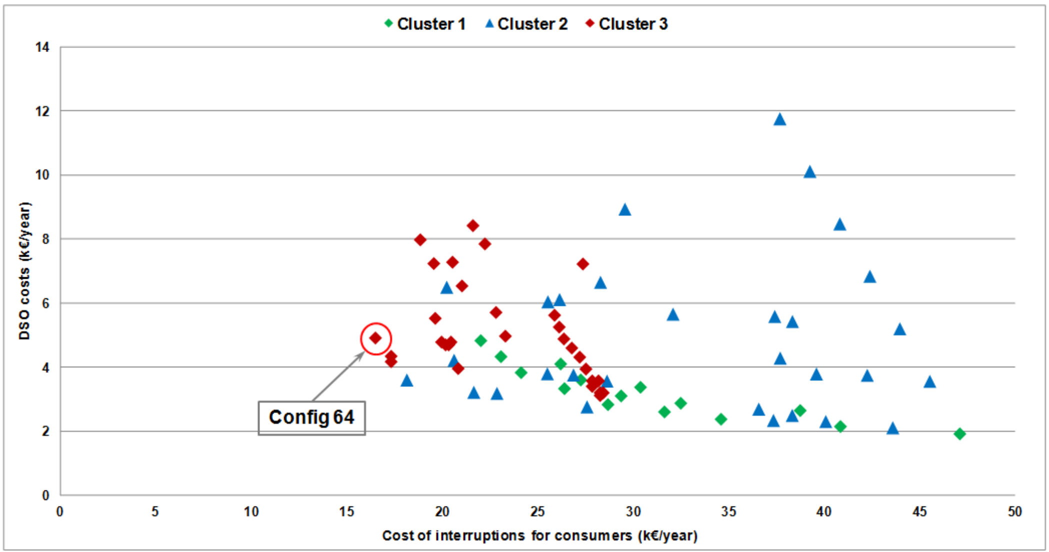

Figure 7-15: Annualized DSO costs versus interruption costs under different configurations of the urban feeder assuming a 50% reduction in investment costs of telecontrolled devices

Lastly, the optimal level of quality which minimizes total social costs (SOTEX) varies a new technologies are introduced. Considering cluster 1 alone, configuration 9 would provide the optimal level of quality. However, this point changes to configuration 23 (highlighted in Figure 7-14) when the all the technology clusters are included, resulting in a 19% reduction in total social costs as compared to configuration 9.

All the configurations in Table 7-6 have been analyzed. Nonetheless, it can be easily seen in Figure 7-14 and Figure 7-15 that several of these configurations provide dominated solutions, i.e. there are other configurations showing lower costs and better reliability.

From the initially considered 75 configurations, only 13 of them are non-dominated: 1, 2, 3, 4, 16, 17, 20, 21, 22, 23, 45, 62 and 64. These 13 configurations, which would constitute the Pareto front of the problem, are represented in Figure 7-16. It can be seen that the slope of the front increases sharply for high levels of reliability due to the high costs of implementing telecontrol functions. Moreover, this figure depicts more clearly the fact that the reliability levels attainable can be extended thanks to the penetration of smart grid technologies.

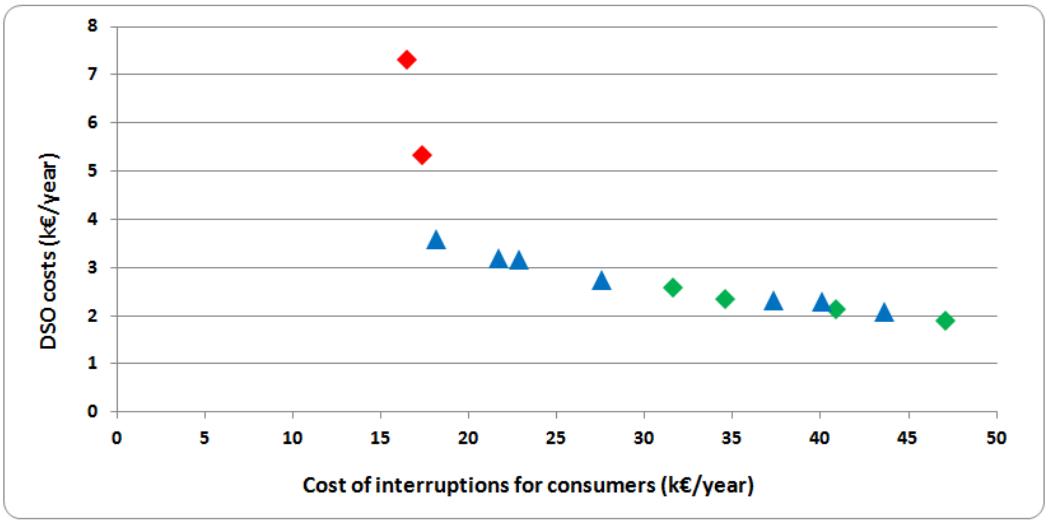

Figure 7-16: Annualized DSO costs versus interruption costs under different configurations of the urban feeder for the non-dominated configurations

7.4.2 Smart metering and the measurement of continuity of supply

The potential of smart meters, through the deployment of an AMI, to reduce the times required to locate a fault in the distribution network and to restore the power supply afterwards is frequently mentioned in the literature (Neenan and Hemphill, 2008; Depuru et al., 2011; McKenna et al., 2012). The impact would be more relevant at LV level where DSOs generally have to rely on the phone calls from end consumers to locate faults. Nonetheless, this would require DSOs to monitor in real-time the data gathered by smart meters and integrate this information within their OMS, thus incurring in additional costs. Hence, this capability would be related to the discussions presented in section 7.4.1, albeit the lack of actual experience with such an application of smart metering hampers quantitative analyses as the ones previously presented.

However, another application of smart meters in relation to continuity of supply that is much less frequently discussed is the possibility to perform a more detailed and accurate recording of power outages (Haney et al., 2009). In fact, a study performed for several Australian regions revealed that integrating quality monitoring and outage detection functions into smart meters presented significant benefits and they were considered some of the key functionalities of smart meters (NERA, 2008). The deployment of smart meters with such capabilities can have relevant consequences for the measurement of reliability in distribution networks.

Its implementation would allow DSOs to substitute current recording systems based on connectivity models, whose accuracy depends to a great extent on how often they are updated, by the smart meters data. Moreover, smart meters would allow DSOs to determine more precisely when each interruption started since this is nowadays based on the phone calls received from end consumers and to compute more precisely the number of consumers affected, which is sometimes done through approximate heuristic rules (CEER, 2012). Additionally, it would be possible to compute load based indices according to the consumers' actual contracted capacity of LV/MV consumers instead of the MV/LV transformation capacity, as done in Spain with the reliability indices TIEPI and NIEPI (see section 7.3.5). Lastly, it will allow regulator to monitor much more precisely individual quality indicators that can be used to implement MQS or facilitate the implementation of detailed non-linear bonus-malus incentive schemes similar to the Norwegian one, incorporating effects such the hour of the day or the day of the week when the interruption occurred.

Nevertheless, there are some open issues that should be analyzed. For instance, such a modification of how reliability indices are computed may cause large fluctuations in the values observed for these indices before and after its implementation. Hence, it would be advisable to set a transitory period, for instance of two years, during which the new indices are computed only for monitoring purposes. Once enough experience and data have been gathered, it would be possible to implement regulatory incentives based on the new methodology.

Furthermore, some DSOs have raised concerns about the use of smart metering data for continuity of supply monitoring[49] in the meetings of the working group on smart grids organized by the Spanish energy regulator during the first half of 2012. These DSOs claim that this methodology could lead to incorrectly considering as distribution network faults those incidents occurring in the segment between the meter and the customer premises or as a result of manipulations performed by end consumers (CNE, 2012). Nonetheless, it is still to be determined whether these effects are more important than errors in connectivity models, inaccuracies in the determination of the start of an interruption or the use of MV/LV transformation capacity instead of actual contracted capacity.

7.5 DG and continuity of supply

Existing studies about distribution reliability and DG analyze how DG may contribute to system reliability through islanded operation (McDermott and Dugan, 2003) or the potential problems that may arise as a result of unintentional islanding (Walling et al., 2008). However, in many countries, e.g. the EU, DG is not owned by DSOs but by private investors. Therefore, DG units could be seen as network users similarly to consumers. This is why it is argued that DG units should pay distribution tariffs as well (Li et al., 2008).

DG units are also jeopardized by supply interruptions since they prevent them from selling part of their production. Therefore, DG could be considered as an additional distribution network user entitled to receive adequate levels of continuity of supply. In order to ensure this, it would be needed to include DG in the computation of reliability indices. However, conventional reliability indices only consider consumers (IEEE, 2001; CEER, 2012). Consequently, DSOs may neglect the consequences of interruptions for DG units when planning and operating the grid. Given the growing penetration levels of DG, this is bound to become a relevant issue. In fact, DG units are already compensated

[49] Within Spanish regulation, RD 1110/2007 (Article 9.11) mandates that the new meters installed to keep record of the number and duration of all the interruptions longer than 3 minutes experienced by the corresponding consumers.

in case of interruptions in Italy, although only direct compensations are used (i.e. aggregated reliability indices including DG are not computed) (AEEG, 2011).

Note that this would apply as long as DG units are considered independent from existing consumers. Under net-metering, DG and consumers would be seen as a single network user from the DSO viewpoint due to the fact that they share a single point of connection to the grid.

7.5.1 DG as an additional distribution network user in bonus-malus systems with linear incentives

Linear incentives generally rely on the quantification of load-based or consumer-based indices[50]. This section will analyse the effect of including DG in reliability evaluations through the rural MV feeder studied in section 7.4.1.1 which corresponds to configuration 16 in Table 7-3 (this was the configuration which yielded the minimum total social cost). The same input data and methodology is used. The continuity indices with and without DG will be computed under several scenarios. In this case, the number and installed power of DG units will be added to that of consumers in order to compute the new indices SAIDI, SAIFI, ASIDI and ASIFI. Equations (7-6) and (7-7) illustrate this calculation for SAIDI and ASIDI respectively. Islanded operation of DG units and any potential degradation of reliability caused by the connection of DG will not be considered.

$$SAIDI_{DG} = \frac{\sum (Cons + DG)_{\text{int}-duration}}{Cons_{number} + DG_{number}} \qquad (7\text{-}6)$$

$$ASIDI_{DG} = \frac{\sum (Cons + DG)_{\text{int}-duration}}{Cons_{power} + DG_{power}} \qquad (7\text{-}7)$$

Two DG penetration levels (1MW and 5 MW) have been analyzed varying the location, size, number and concentration of DG units. In total, the 10 scenarios shown in Table 7-8 have been evaluated. In scenarios 1-2, DG is evenly distributed across all feeder sections. In scenarios 3-5, DG is concentrated in the second half of the feeder, where reliability is poorer. On the other hand, in scenarios 6-8 DG is concentrated in the first part of the feeder, which presents higher reliability levels. Finally, scenarios 9-10 show the effect of locating a large DG unit in different feeder sections.

Scenario number	Total DG capacity [MW]	Total number of DG units	Unit size [kW]	Distributed among sections
0	0	0	0	-
1	1	8	125	T1-T8
2	5	400	12,5	T1-T8
3	5	400	12,5	T2,T6-8
4	5	4	1250	T2,T6-8
5	1	4	250	T2,T6-8
6	5	400	12,5	T1, T3-T5
7	5	4	1250	T1, T3-T5
8	5	4	250	T1, T3-T5
9	1	1	1000	T1
10	1	1	1000	T8

Table 7-8: DG scenarios for reliability analysis

[50] For linear incentive schemes that rely on the concept of ENS, the proposals presented in section 6.5.2 would apply.

The results obtained are summarized in Table 7-9. These results show that including DG in the computation of reliability indices can significantly affect continuity levels, especially in areas with high DG concentration. Since consumers have been assumed to be equally distributed among all feeder sections, reliability indices do not vary in the scenarios where DG is evenly distributed. Moreover, it can be seen that load-based reliability indices tend to be more sensitive to the existence of DG than customer-based indices because DG units normally show higher capacities than residential consumers (all consumers were assumed to be residential). Finally, computing reliability indices that include DG can either improve or deteriorate the levels of continuity of supply measured. As it would be expected, reliability indices tend to improve when DG is located in the sections with higher reliability (closer to the head of the feeder) and vice versa. This is because a higher weight is being placed in those areas where DG is connected.

Note that, under the conditions assumed in this case, the presence of DG does not modify the actual number or duration of the interruptions. However, the values of the continuity of supply indices that are measured for regulatory purposes change due to a modification of their calculation formulas. Consequently, using reliability indices with DG in continuity of supply regulation can shift distribution investments towards those areas where DG is located.

Scenario number	ΔSAIFI	ΔSAIDI	ΔASIFI	ΔASIDI
1	0%	0%	0%	0%
2	0%	0%	0%	0%
3	-0,04%	-0,03%	-3,33%	-2,86%
4	3,33%	2,86%	10%	8,57%
5	0,04%	0,03%	10%	8,57%
6	0,04%	0,03%	3,33%	2,86%
7	-3,33%	-2,86%	-10%	-8,57%
8	-0,04%	-0,03%	-10%	-8,57%
9	-0,03%	-0,03%	-10%	-10,95%
10	0,02%	0,02%	5,56%	5,56%

Table 7-9: Variation in the reliability indices in rural test feeder with DG (negative values imply improvements in continuity of supply)

However, as mentioned above, customer-based indices can be rather insensitive to the presence of DG. On the other hand, ASIDI and ASIFI indices with DG are not as straightforward to compute. In some countries, consumers do not have a fixed contracted capacity since they are charged according to their actual maximum consumption in a month, which generally varies through time. Therefore, load-based indices may not be measured and compared over time. Moreover, in other countries, such as Spain, ASIDI and ASIFI (TIEPI and NIEPI respectively in Spanish) are not computed considering the contracted capacity of LV consumers but the sum of the contracted capacity of MV consumers and the MV/LV transformation capacity. Since the presence of DG at LV level may not require new transformation capacity or even, in the long-term, reduce the necessary MV/LV transformation capacity; the reliability indices computed in this way may not be suitable to account for DG.

Furthermore, incentive rates may also need some adaptations as the function accounting for the cost of interruptions for network users would also change due to the inclusion of DG. The cost of interruptions for DG units will be dealt with in more detail in the next subsection in the context of non-linear quality incentive schemes. In addition to this, similarly to the case of consumers, regulators may extend the application of GS for DG as well in order to prevent the existence of worst-served DG units.

Lastly, the implementation of such indices could be hampered by the fact that reference values are oftentimes set as an average of past reliability indices measured. Thus, modifying the methodology to compute these indices may render this approach useless due to lack of comparability with historical values. Consequently, other approaches should be investigated. This can be avoided, for instance, by correcting revenue allowances with a quality factor as done in The Netherlands (Niesten, 2010). This quality factor is higher for those DSOs whose reliability levels are higher than the average at national level. Notwithstanding, such a mechanism, as it stands now, would not incorporate the impact of geographical on quality and provides a short term view to quality improvements due to the annual revisions of the factor.

7.5.2 DG as an additional distribution network user in bonus-malus systems with non-linear incentives

As shown before, under non-linear incentive schemes distinct cost functions or damage functions are defined for each type of network user. The main advantage of such an approach, as compared to the linear incentives, is that it allows incorporating additional aspects that influence the effects of interruptions on consumers in the same incentive scheme. These issues comprise, among others, the effects of short interruptions, the existence of different types of network users or when interruptions take place.

Norway is the European country which presents the widest experience in using this approach. The formula used to compute the cost of an interruption since 2009 is shown in (7-8) (CEER, 2012). A distinct cost function is used for each of the six groups of consumers considered: agriculture, residential, industrial, commercial, public, large industry. Planned interruptions are considered in the formula through a correction factor. The reference time can be different for each consumer group and is selected to represent a worst-case scenario, usually that of peak demand. Further details can be found in (Kjolle et al., 2008). (Kjolle et al., 2009).

$$IC_j = c_{ref}(r) \cdot f_{Ch} \cdot f_{Cd} \cdot f_{Cm} \cdot P_{ref} \tag{7-8}$$

Where:

IC_j	Cost of an interruption in time j [NOK]
$C_{ref}(r)$	Cost for an interruption of duration r at the reference time [NOK/kW]
f_{ch}	Correction factor for hour of the day of the interruption (6 periods)
f_{cd}	Correction factor for day of the week of the interruption (weekday, Saturday or Sunday/holiday)
f_{cm}	Correction factor for month of the interruption
P_{ref}	Power interrupted at reference time [kW]

Including DG as a network user in reliability evaluation, as proposed in this thesis, under this regulatory design could be easily done by defining a cost function associated with DG units. This function would aim to estimate the cost of the "energy non-produced" (ENP) by DG due to the occurrence of an interruption. Adding this new ENP to the ENS to consumers would yield a total cost of interruptions for network users, both consumers and DG that would be used to compute the regulatory incentives.

Such a cost function would presumably be intimately related to, although not necessarily be equal to, the expected selling prices of the electricity produced by DG. Hence, the structure and level of support payments, if applicable, are key issues. Moreover, when feed-in premiums (FIPs), green certificates or no support payments are in place, electricity market prices are also very relevant. Consequently, similarly to what happened with the damages suffered by consumers, the DG cost function can vary significantly on a country basis. Moreover, the time component may be very relevant, except in the case of DG units receiving flat feed-in tariffs (FITs). Additionally, the interruptions costs could depend on the generation technology as it may not be possible for some technologies to restart production immediately after supply restoration, e.g. thermal units under very long interruptions may incur in additional start-up costs.

Therefore, the number of new groups of network users that should be defined depends mostly on the selling options for DG production and the technological characteristics. The parameters that regulators should set are the following:

- Value of the ENP and time-related correction factors: the value of ENP should basically be determined according to the selling prices received by DG, which essentially depend on a time component and the support payment options[51]. Start-up costs will be neglected hereinafter as these as assumed not to be significant for small DG units. The main advantage for regulators, as compared to the case of consumers, is that these costs are much easily gathered since they are publicly available and do not require carrying out surveys of other complicated analyses.
    - Units receiving a FIT: the value of the ENP for these generators would correspond to that of the FIT times the duration of the interruptions affecting them. A correction factor could be introduced in case the FITs show a time-of-use (ToU) differentiation. For instance, in the case of Spain, some DG units can opt for a two-period ToU FIT (Cossent et al., 2011a).
    - Units receiving a FIP, renewable certificates of under free competition: in all these cases, the price of electricity is the key variable. A simple yet effective approach to value the ENP could consist in estimating an average market price for each of the time periods considered. Similarly to the Norwegian formula, three time factors are proposed. Concerning intraday variations, the number of periods considered should be at least two (peak/off-peak). Moreover, weekly variations and calendar effects could be captured by defining three periods, i.e. weekdays, Saturdays and Sundays/holidays. Lastly, the market price variations across the year could be reflected by considering no less than two periods, being these winter and summer. The value of FIPs and an average yearly price of renewable certificates would then be added on top of the average market price for each of the time periods defined.
- Reference power: this parameter could be drawn from installed nameplate capacities. However, since DG technologies often present relatively low capacity factors, this could lead to an overestimation of the power interrupted. For instance, in order to compute the compensations to MV DG units in Italy, the actual power

[51] This raises an interesting discussion, which falls outside the scope of this work, about whether the full expected income should be included in this function following the principle of *lucrum cessans.* This discussion would be similar to the case of generators being curtail so as to ensure a secure system operation.

interrupted is used when this information is available and a fixed value of 70% of rated capacity otherwise (AEEG, 2011). A more precise methodology would be based on the definition of standard generation profiles for each DG technology. These generation profiles would show representative variation of DG output during the day and also along the year. This latter aspect can be particularly relevant for technologies such as solar PV, wind generation or CHP (subject to a seasonal heat demand). Furthermore, these profiles could change geographically, for example according to solar radiation levels.

7.6 Summary and conclusions

Incentive regulation normally requires specific mechanisms to prevent the deterioration of quality of service. In electricity distribution, quality of service comprises three main aspects, namely commercial quality, power quality and continuity of supply. Economic regulation of DSOs generally focuses on continuity of supply due to its strong relation with the costs incurred by DSOs. In distribution networks, continuity of supply is usually measured as the number and duration of the interruptions suffered by the consumers in a specific region over a period of time of typically one year. Existing surveys show that there is a wide variety of reliability indices that are used by regulators to monitor continuity of supply in distribution grids.

The regulatory incentives concerning continuity of supply essentially intend to make DSOs internalize the cost of interruptions for consumers so that these are taken into account in the network investment and operational decisions. The goal of these regulatory mechanisms should be to encourage DSOs to reach the optimal level of quality, in which the total social costs (sum of consumers' cost of interruptions and costs incurred by DSOs) are minimized. In this chapter, two main theoretical approaches that fulfil this requirement have been described, i.e. incentives with linear and non-linear incentive rates.

Linear incentives are the most widely applied, presumably due to its simplicity. Nevertheless, an optimal design theoretically requires accurate estimation of both the cost of interruptions for consumers and the costs for DSOs of improving reliability levels. The latter cost curve is scarcely studied. Therefore, current linear incentive schemes, in spite of being effective, may not lead to an optimal outcome. On the other hand, non-linear schemes are more sophisticated and are based on the estimation of a detailed cost function reflecting the consequences of interruptions for consumers. These are non-linear because the incentive/penalty rates faced by DSOs are a function of the frequency and duration of the interruptions experienced by end consumers.

However, several practical issues may hamper the implementation of the previous theoretical approaches. Most of them are related to the difficulties in the estimation of the consumers' and DSOs' costs curves. In real-life, these curves are not immediately observable, can evolve over time and may vary across regions. In order to overcome this limitation, several methods have been developed to estimate the curves. Conventionally, the curve corresponding to the costs for consumers has been more extensively analyzed. This is reflected in the fact that a wide variety of methods for its estimation can be found. Among these, survey based methods provide the most accurate results, in spite of being more complex and burdensome for regulators. On the other hand, the costs of improving continuity of supply seem to have been rarely studied. The main reason for this may lie in the fact that it is not possible to define a sharp line between quality driven costs and other costs. Only a few publications addressing this gap have been found. All of them rely on econometric analyses, using either actual data from real firms or the results of an engineering norm model. Further developments are needed to gain deeper insights into these cost functions and how to use this information in regulation.

As a result of the previous problems, regulators usually include mechanisms to account for uncertainties and stochastic effects that may have an undesirable impact on DSO revenues, such as deadbands and cap & floor systems. Moreover, linear incentive schemes generally incorporate a differentiation per type of region (rural, urban, etc.). Another issue, which is not usually discussed, is how incentive schemes interact with the overall revenue determination. In theory, incentive schemes should be enough by themselves to bring quality improvements. However, doing this would in practice deter DSOs from investment in quality improvements due to the frequent reviews of reference values. Consequently, continuity incentives may not be seen as a way to acknowledge for all the quality driven costs, but as a means of encouraging DSOs to prevent quality deterioration. Hence, reference values should be defined in accordance with the level of allowed revenues. This stresses the need for a quality-integrated cost benchmarking, i.e. considering quality as an additional cost driver.

After reviewing these issues, the chapter turned to the evaluation of how the penetration of smart grid technologies and DER can affect the way continuity of supply is regulated. Firstly, the effect on the penetration of new technologies on the marginal cost of quality improvement, optimal levels of quality and feasible levels of quality has been studied for two distribution feeders, a rural overhead feeder and an urban underground feeder. The results show that the introduction of new technologies can allow DSOs to attain higher reliability levels, which may be unreachable in the absence of these technologies. Additionally, this was sometimes achieved in a more cost-effective way, thus driving the socially optimal levels of quality up. However, the effectiveness of the different technologies shows a strong dependence upon the characteristics of the network and the technology costs. For example, reclosers yield significant benefits thanks to the reduction of temporary faults in the rural feeder, whereas increasing the number of sectionalizing devices proved to be essential in the urban feeder. Telecontrolled devices still seem to require significant cost reductions in most cases, although they could be efficient for some urban feeders.

Additionally, smart metering can also play a relevant role in relation with continuity of supply. Smart metering could be used to reduce fault location times through an AMI, although this would still require much more experience with smart metering data managing. Notwithstanding, smart metering could indeed play a role in the measurement of continuity of supply in the shorter term. The more detailed and accurate recording of interruptions would allow regulators to implement more advanced incentive schemes, e.g. time differentiation, and substitute approximate models by actual measurements, particularly at LV level.

Last but not least, this chapter has analyzed and discussed the potential inclusion of DG into the calculation of distribution reliability indices. Reliability indices used to regulate continuity of supply normally only consider consumers. Nonetheless, the penetration of DG may require revisiting this paradigm as DG units ought to be considered as network users which incur in costs due to failures in the distribution grid. Therefore, this thesis proposes to incorporate DG in quality incentive schemes. Furthermore, this chapter has discussed how this can be done both under linear and non-linear incentive schemes.

The former type of incentives, have been analysed by evaluating several reliability indices for the same rural feeder previously mentioned. The reliability indices that would be obtained for a certain feeder configuration with and without including DG in the computation of reliability indices under several DG scenarios were computed and compared. The results showed that including DG in the computation of reliability indices can significantly affect continuity levels, especially in areas with high DG concentration, and that this effect can be either positive or negative depending on the location and concentration of DG units. Moreover, load-based reliability indices tend to be more sensitive to the existence of DG than customer-based indices because their capacity tends to be larger. Notwithstanding, load-based indices with DG may be hard to compute when consumers do not contract a specific capacity or where the transformation capacity is used as a proxy for LV power. Therefore, DG should be included in the reliability measurement and regulation to prevent DSOs from neglecting its presence.

Accounting for DG in non-linear incentives would require estimating a new variable that has been named as the energy non-produced or ENP, whose role would be similar to the concept of ENS conventionally used for consumers. Thus, a function of the cost of ENP can be used as reliability indicator and added to the cost of ENS in order to obtain the total cost of interruptions for distribution network users. In order to implement such a scheme, two main parameters have to be determined. Firstly, the cost of the ENP would be set on the basis of electricity prices and DG-RES support payments. Therefore, the design of RES and CHP support schemes plays a relevant role in this regard. Secondly, the reference power ought to reflect the loss of DG production during the interruption. This parameter could be quite relevant to prevent overestimating the ENP for intermittent DG units.

Main conclusions:

- Continuity of supply incentives make DSOs internalize the cost of interruptions for consumers so as to encourage them to reach the optimal quality levels. An optimal incentive scheme can be design either with linear or non-linear incentive rates
- Several practical issues hamper the implementation of theoretical approaches, mostly related to the estimation of the consumers' and DSOs' quality costs curves. Further work is needed to attain deeper insights into these functions and their application
- Continuity incentives may not be solely responsible for all quality driven costs, but as a means of encouraging DSOs to prevent quality deterioration. Hence, reference values should be defined in accordance with the level of allowed revenues, thus stressing the need for quality-integrated cost benchmarking
- The penetration of new network technologies allows attaining higher reliability levels and, in some cases, increases the socially optimal quality levels. The effectiveness of the different technologies strongly depends upon the network characteristics and technology costs.
- Smart metering could improve the measurement of continuity of supply in the short term and allow regulators to implement more advanced incentive schemes in the longer term
- It is proposed to incorporate DG in quality incentive schemes as DG units can be considered as network users. This can be done both under linear incentive schemes, by defining new reliability indices, and non-linear incentive schemes, by defining a function to estimate the cost of the energy not produced

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8. Setting incentives to reduce energy losses

Another aspect of electricity distribution that is frequently the focus of regulatory incentives is that of energy losses, which can be defined as "*the difference between the amount of electricity entering the transmission system and the aggregated consumption registered at end-user meter points*" (ERGEG, 2008). Energy losses are frequently sorted into two different groups depending on what is causing the losses.

On the one hand, technical or physical losses occur as a result of the heat and noise produced when electricity flows through network components due to their inherent resistance (ohmic or copper losses), known as Joule effect, or as a result of several physical phenomena, mostly hysteresis and eddy currents, that take place in the magnetic core of power transformers. The former type of losses depends on the loading of network components as these are proportional to the resistance of network components and the square of the current flowing through them. On the contrary, the losses in the transformer cores occur whenever they are connected and are proportional to the operating voltage. Moreover, they depend on the characteristics of the material with which magnetic cores are built and its constructive features.

On the other hand, non-technical or commercial losses correspond to consumption that is not appropriately metered. These can be caused by consumptions in the DSO's premises, e.g. transformers cooling, energy theft through illegal connection and meter tampering, non-metered consumptions such as public lightning (in some countries public lighting is billed on the basis of estimated consumption) or errors in metering and billing (ERGEG, 2008).

Energy losses usually amount to 10-15% of the total electricity produced (ERGEG, 2008), most of them at distribution level. However, the amount of energy losses can be very different across countries or regions, mainly due to the inherent characteristics of the distribution areas (load density, length of lines, weather conditions) and the relevance of commercial losses. In some countries it is possible to find areas with a very scattered population and high levels of non-technical losses which present losses well above this 15%. For instance, some DSOs in Argentina or Brazil face energy losses of 40% and above. It can be seen in Figure 8-1 and Figure 8-2 that these DSOs are also those which present the highest shares of commercial losses. In some cases, these can be even higher than technical losses.

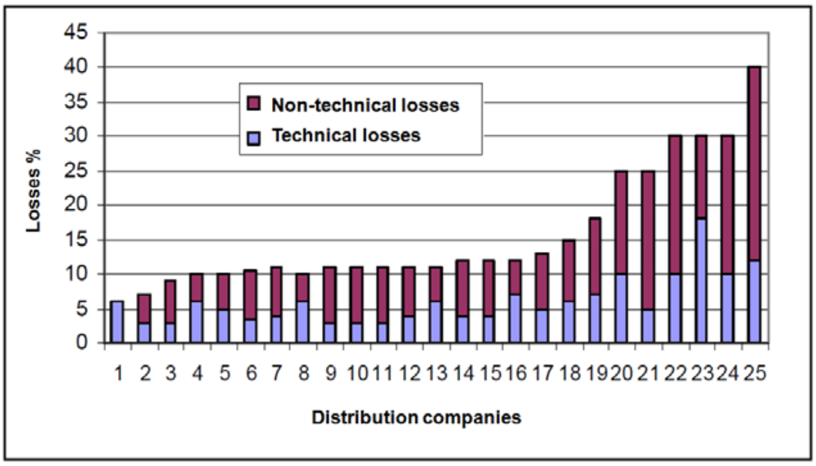

Figure 8-1: Estimation of the technical and non-technical losses of Argentinean DSOs from (International Copper Association, 2008)

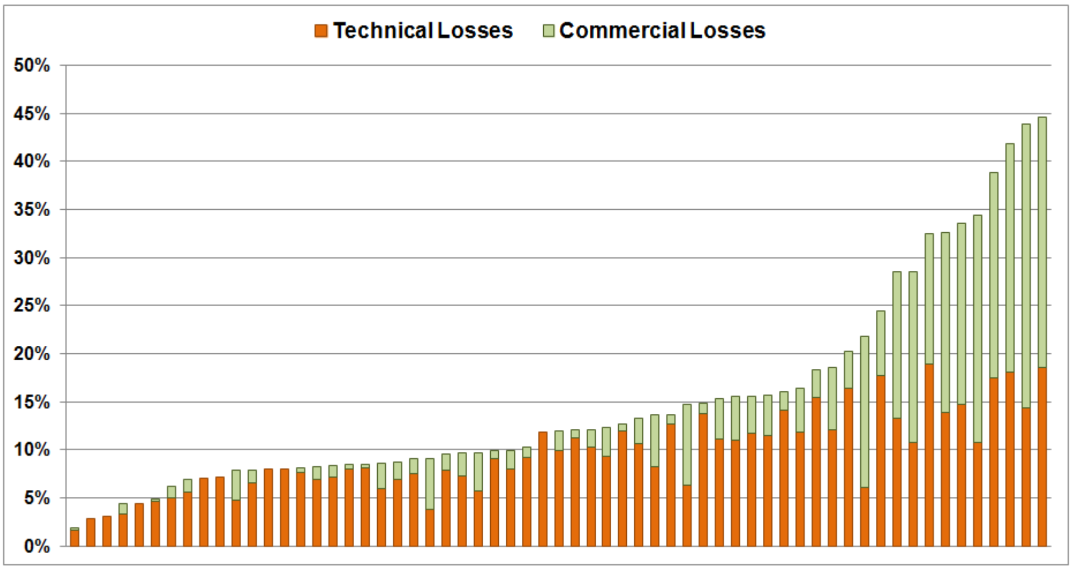

Figure 8-2: Technical and non-technical distribution losses for 61 Brazilian DSOs in 2005. Own elaboration with data from (Marqués de Araujo, 2007)

Unbundled DSOs do not produce, purchase or sell electricity to end consumers. Therefore, in the absence of specific mechanisms, such as penalty/reward schemes or the obligation to purchase losses, they would be insensitive to the occurrence of losses. However, it is DSOs which are better positioned to reduce them. Commercial losses require specific measures aiming at improving metering accuracy and preventing energy theft, whereas technical energy losses are more specific to the network activities of DSOs and the investment decisions made. Therefore, regulatory incentives have been frequently implemented to make DSOs internalize the effects of energy losses into their investment and operation decisions.

Nonetheless, the penetration of DER and smart grid technologies may require new approaches to the determination of regulatory incentives for energy losses reduction. On the one hand, smart distribution grids offer DSOs new strategies to mitigate losses. In fact, the reduction of non-technical losses is seen as one of the major drivers for smart grids implementation in Brazil (Barroso, 2012). On the other hand, as stated in chapter 2, DER can significantly alter power flows through distribution grids, thus affecting mainly technical energy losses.

The main objective of this chapter is to analyze how incentives to reduce energy losses should be designed under this new environment. Section 8.1 starts by reviewing why it is necessary to regulate energy losses, the actions that DSOs can perform to reduce (technical) energy losses and how the different parameters required in such incentive mechanisms can be determined. Subsequently, section 8.2 turns to the analysis of how smart grids and DER impact energy losses and the means to reduce them. Moreover, this section addresses the problem of how to define these incentive schemes in this new context. Lastly, section 8.3 presents some concluding remarks.

8.1 Regulating energy losses in distribution networks

This section will describe the relevance of energy losses regulation at distribution level and illustrate the most common means through which DSOs can reduce them. Furthermore, the different approaches to the regulation of energy losses from a theoretical and practical point of view will be presented and discussed.

8.1.1 Why regulate energy losses

Energy losses occurring in distribution networks increase the cost of supplying electricity to end-consumers as well as CO_2 emissions due to the need to generate more electricity to supply the same demand. Therefore, electricity companies should be encouraged to reduce them in cost-effective ways. Vertically integrated utilities face a natural incentive to reduce losses as they bear the full cost of losses. However, the unbundling of electricity distribution from generation and retail removes this natural incentive. Hence, DSOs would not receive any benefit from the reduction of losses unless specific regulatory incentives are introduced. This is relevant because network operators can reduce the volume of energy losses through specific operational and planning strategies (Arritt et al., 2009).

Concerning network operation, most measures aim at reducing the variable or copper losses. For instance, local reactive power compensation, usually through the connection of capacitor banks or setting requirements on the power factors of network users, is a conventional operational strategy that reduces energy losses (and mitigates voltage drops) by lowering the loading of network components. Additionally, DSOs may also reconfigure the network to equalize the loading across network components and reduce the length of feeders. Moreover, the optimization of voltages can also lower the variable energy losses. Generally, higher voltage levels lead to lower loading of network components. Nonetheless, the loads connected at lower voltage levels tend to deviate significantly from the constant-power load model, thus active and reactive power consumption change with the voltage. This makes it difficult to reduce energy losses through voltage optimization (Arritt et al., 2009). On the other hand, the disconnection of transformers in periods of low demand, e.g. at night, prevents the associated fixed losses from occurring.

Nonetheless, the most important actions in terms of energy losses reduction are related to the long-term network planning and design (ERGEG, 2009). A common way to achieve a reduction in energy losses is to reduce the length of the feeders and to install thicker conductors that what is strictly required to comply with capacity constraints. In fact, the optimal average utilization of network assets, including the cost of losses at the design phase, could reach a value of 30% (OFGEM, 2003). Unbalanced phase loading results in higher losses in at least one of the phases and the neutral (in 4-wire networks). Therefore, balancing the distribution of demand across the three phases when connecting new consumers can be another way to reduce losses (Arritt et al., 2009).

Furthermore, the voltage level at which the distribution network is operated can be increased to lower losses. This can be done, by replacing one voltage level with a higher one (reducing variable losses) or by removing intermediate HV/HV or HV/MV transformers (reducing fixed losses). For instance, in the UK a DSO suggested replacing the 66kV voltage level with a 132kV one, whereas another proposed to perform a direct 132/11 kV transformation instead of a two-step transformation 132/33 kV and 33/11 kV (OFGEM, 2003). Lastly, it is possible to invest in new transformers which present reduced no-load losses thanks to the use of innovative materials, e.g. amorphous iron cores.

However, many of the previous measures present tradeoffs with other regulatory objectives and incentives. For instance, disconnecting transformers at night may jeopardize network redundancy, which can potentially negatively affect continuity of supply. On the other hand, upgrading conductors may be considered inefficient due to the low utilization factors as incentive regulation has driven some DSOs to implement an asset sweating strategy. Furthermore, as previously shown, many of the actions to reduce energy losses can only be implemented in the longer-term through investment decisions. Consequently, the regulatory incentives to reduce energy losses should be carefully aligned with the overall revenue determination and other incentives ensuring the implementation of cost-efficient measures over the long-term.

Lastly, DSOs can also be responsible for reducing commercial losses, or for accurately computing energy losses, when they perform metering activities. Incorrect or infrequent meter readings can have a significant impact on the measured losses and the level of non-technical losses as incorrect billing may occur. Therefore, it is necessary to ensure that appropriate metering requirements are put in place.

8.1.2 How to regulate energy losses

Contrary to the case of quality of service, network users are neither directly affected by the occurrence of energy losses, except for the increase in overall system costs, nor worst-served consumers (in terms of losses) can be identified. In other words, whilst it is true that reducing energy losses may be more expensive in some areas, consumers in areas with higher losses do not experience worse quality. Consequently, MQS or premium quality contracts related to energy losses are not appropriate mechanisms for their regulation.

Therefore, the main approach to encourage DSOs to reduce energy losses is through a bonus-malus mechanism. The theoretical foundations for the determination of these incentive schemes that have been presented in chapter 6 in the context of quality of service regulation are also relevant for the regulation of energy losses. Therefore, the socially optimal level of losses would correspond to the point where the marginal cost of energy losses for consumers and the marginal cost of reducing losses are equal in absolute value. Notwithstanding, several of the practical issues discussed regarding continuity of supply are not immediately applicable to energy losses regulation. The remainder of this section will review the major practical difficulties faced by regulators specifically related to the promotion of energy losses reduction and the most common incentive schemes actually implemented by regulators.

8.1.2.1 Practical issues in energy losses regulation

Firstly, contrary to continuity of supply for which it was common to monitor two indices related to the frequency and duration of interruptions respectively, the measurement of energy losses can be done through a single indicator. This indicator is generally either an absolute value expressed in energy units or a percentage representing energy losses as a share of the total energy injected into the distribution grid or the total energy consumed. In order to facilitate the comparison across DSOs, particularly when they supply areas of a very different size, the latter option is generally preferred.

Nevertheless, (ERGEG, 2008) shows that, when expressed as a percentage, there is not a common standard as to whether energy losses are to be computed as a percentage of the energy distributed (input) or the energy consumed (output). According to this document, there is even one European country (Poland) where a different approach is used to compute losses in transmission and distribution. These two alternatives are illustrated in (8-1). In principle, neither of them is superior to the other as both correspond to different variables. Mathematically speaking, the difference lies in whether losses are included in the denominator or not. The former alternative would provide the share of the energy injected into the distribution network that is lost in the distribution network, whereas the latter would provide the additional amount of electricity that needs to be injected into the distribution grid in order to supply the demand.

$$Losses_{ref}^{in}(\%) = \frac{E_{injected} - E_{Consumed}}{E_{injected}} \quad ; \quad Losses_{ref}^{out}(\%) = \frac{E_{injected} - E_{Consumed}}{E_{consumed}} \qquad (8\text{-}1)$$

As compared to the case of continuity of supply, the curves representing the value of losses for consumers and the costs incurred by DSOs to reduce them have not been as analyzed in as much detail. In practice, the marginal cost of losses for consumers is generally assumed to be independent of the level of losses, although it indeed can vary according to other variables. This is because the value of losses for consumers is conventionally linked to the electricity price and the cost of CO_2 emissions. The main advantage of this is that electricity prices are publicly available and can be considered to adequately reflect the value of the excess of electricity that needs to be produced to cover energy losses. Moreover, some regions have also implemented market mechanisms for CO_2 emissions, e.g. the European ETS[52].

Nonetheless, as a result of this, the time component which was sometimes neglected in continuity of supply incentives, especially when linear schemes were implemented, becomes much more relevant. This happens because electricity prices normally vary significantly during the day and along the year, except for systems with flat prices such as those dominated by hydro power generation. It can be argued that distribution losses present some additional costs, besides the cost of generating the energy, such as the additional capacity required from the transmission system[53] (OFGEM, 2003). Nonetheless, estimating these costs would be very complicated due to the need to identify the specific amount of spare capacity that is specifically driven by energy losses at transmission level, which would be particularly hard given the significant lumpiness of transmission investments. Therefore, using only electricity market prices is considered to be a much simpler and transparent approach (KEMA Consulting GmbH, 2009).

On the other hand, the curve representing the distribution costs to reduce energy losses has been rarely studied in the literature. Several publications identify the strategies that DSOs can follow to reduce energy losses (OFGEM, 2003; Arritt et al., 2009), and some even perform cost-benefit analysis of the implementation of these measures under different regulatory incentive designs (KEMA Consulting GmbH, 2009). Nonetheless, according to the author's knowledge, (Jamasb et al., 2010) is the only publication which specifically evaluates the costs incurred by DSOs to reduce energy losses. Through regression analyses on a set of panel data of UK's distribution companies in the period 1993-2005, the authors estimate a marginal cost of losses reduction averaged across all the observations of 2.8p/kWh[54]. Nevertheless, the results presented therein show a high

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[52] Note that in those countries where generators can trade emission allowances, the cost of CO_2 will be internalized into the electricity prices as part of the opportunity cost of electricity production.

[53] The additional costs incurred at distribution level to accommodate losses should not be included in the valuation as incentive rates should only include the costs exogenous to DSOs. When faced with incentives based on this valuation, DSOs would internalize the exogenous cost of losses and minimize the total social costs.

[54] Assuming an exchange rate of 1€ = 0.8£ (approximate value at mid-September 2012), this would correspond to a value of 3.5 c€/kWh.

variability among DSOs with values ranging from 11p/kWh to -11p/kWh (the meaning of the negative values is not discussed).

Despite the lack of research in this area, this may not be considered a critical issue. As explained in chapter 6, continuity of supply regulation required estimating the distribution cost curve only in the case of linear incentive schemes as it was necessary to know the optimal level of quality. Otherwise it would be impossible to obtain the marginal cost of quality at the point where social costs are minimized because these marginal costs changed with the level of quality attained. However, due to the fact that the marginal value of losses can be assumed to be constant with the level of losses[55] (albeit it changes through time), knowing this value is enough to the design of (theoretically optimal) incentive schemes. Notwithstanding, further research on this topic would provide a deeper understanding of the strategies adopted by DSOs to reduce energy losses and the effectiveness of regulatory incentives. Thus, it would be possible to answer questions such as the extent to which DSOs could be expected to reduce losses with a given level of incentives.

Owing to the fact that energy losses do not have an immediate impact on network users, setting separate incentives for each type of distribution area (urban, rural) is not relevant. In this case, DSOs should be encouraged to reduce energy losses at system level, taking action wherever it is more cost-effective to decrease losses, since the risk of having worst-served consumers does not exist.

Moreover, the discussion presented in chapter 7 about the effect of stochastic effects and uncertainty is relevant for energy losses too. Load profiles and electricity prices can be show great variability as a result of variables outside the control of DSOs, which at the same time will affect the level of losses and their value. Therefore, it is common to set deadbands or cap/floor mechanisms on the incentives for energy losses reduction to mitigate these risks.

Finally, chapter 7 presented a discussion on the relation between the regulatory incentives and the overall revenue determination and updating of the RAB. As described in section 8.1.1, several of the measure that DSOs can take to reduce losses required long-lived investments e.g. low-loss transformers or conductor upgrading. Consequently, the aforementioned discussion is also applicable to the case of energy losses regulation. Hence, incentives to reduce losses may not be seen as a stand-alone tool that should compensate for all the losses-driven expenditures but as a complement to the determination of overall allowed revenues. In order for both regulatory tools to be consistent, cost benchmarking should consider the levels of energy losses too.

8.1.2.2 Regulatory mechanisms promoting reductions in distribution energy losses

The main goal of energy losses incentive schemes is to make DSOs internalize the cost of energy losses for the power system into their operational and planning decisions. Note that an alternative would consist in implementing an input based regulatory mechanism through which DSOs are directly remunerated for installing certain kinds of equipment. Nonetheless, this would require regulators to identify the most cost-effective solutions

[55] Due to this, the function representing the value of losses would be linear. Consequently, it would be needed to set reference values beyond current levels in order to share tha gains with consumers. Otherwise, similar benefit allocation problems as described in chapter 7, section 7.2.2.1.2 could arise.

and evaluate their impact on energy losses. This would yield a large regulatory burden and a preference of CAPEX solutions over OPEX solutions (OFGEM, 2003). Nonetheless, this could be partly addressed by including in the RAB those investments adequately justified in terms of losses reduction in the investment plans submitted to the regulators by DSOs that were proposed in chapter 5. In the last DPCR, OFGEM has adopted a similar mechanism to encourage investments in low-loss equipment (OFGEM, 2009).

Thus, on the ensuing the focus will be placed on bonus-malus incentive schemes. Several approaches for their implementation, being it possible to broadly categorize them into:

- Setting a reference value, either in absolute (kWh lost) or relative terms (% of losses over energy distributed), and an ex-ante fixed incentive rate in €/kWh. This is the scheme implemented, for instance, in the UK or Portugal (OFGEM, 2009; Cossent et al., 2011).
- Setting a reference value and incentive rate that varies over time. This time differentiation can range from a simple two-period scheme (peak/off-peak) to an hourly valuation of the cost of losses. Moreover, the incentive rate can be either fixed ex-ante by regulation or be computed ex-post on the basis of actual market prices. This option is the one currently in place in Spain (Cossent et al., 2011).
- In several countries, DSOs have to buy the expected amount of energy losses through market mechanisms such as spot markets, bilateral trading or specific auctions. This is done, among others, in Austria, Czech Republic, Finland, France, Norway or Sweden (ERGEG, 2008). If only a pre-defined amount of the losses purchased is included into the allowed revenues, this is de facto a bonus-malus incentive scheme. Among the aforementioned countries, this is the case in Austria, Czech Republic, Norway and Sweden (ERGEG, 2008).

When deciding upon the most suitable incentive scheme, regulators should consider several factors. The first relevant characteristic is whether the incentive rates show a time differentiation. The main advantage of fixed incentive rates is their simplicity. Nonetheless, time-independent incentives fail to reflect the true cost of losses for the system as the value of losses at peak periods may be much higher than during off-peak periods. However, introducing a time differentiation in incentive rates requires a more detailed measurement of energy losses. Since hourly consumption/generation data for all network users is not generally available, this frequently requires performing estimations about load/generation profiles through empirical assumptions or software models based on actual aggregated metering information (ERGEG, 2008; ERGEG, 2009).

Moreover, depending on how the mechanism is implemented, it may be needed to set reference values for each one of the periods considered. For example, the Spanish regulator defines for each DSO specific loss coefficients (used to define the reference losses) depending on the time of day. A detailed description of the methodology and the results obtained can be found in (CNE, 2010). On the other hand, some countries define time-dependent incentive rates (e.g. by mandating DSOs to buy energy to compensate for distribution losses at the market) but a single reference value expressed either in monetary terms or as the percentage of losses over the total energy distributed. For example, Swedish DSOs had to buy energy losses at the market but the allowed losses were computed ex-post using the NPAM described in chapter 3 and valued at the average market price of the preceding year.

An additional aspect that regulators should consider is how to provide DSOs with enough certainty to drive investments in energy losses reduction. For instance, when incentive rates are linked to ex-post market prices, DSOs would not know ex-ante the level of the incentive. Furthermore, if DSOs have to purchase energy losses at the market, besides the added complexities of becoming market agents, they would also have to forecast the level of losses and operate in balancing markets. All these factors can create uncertainties and hamper this type of investments. Therefore, part of this risk can be shifted to consumers by fixing incentive rates ex-ante. These fixed regulated values may provide higher stability as DSOs would be capable in advance of forecasting the level of the incentives they will be given.

Another source of uncertainty can be related to how the reference values are measured. DSOs cannot influence the overall demand or market prices. Hence, setting reference values expressed as a cost of losses (in €) or in energy units (kWh) can cause windfall profits/losses for DSOs. In the survey presented in (ERGEG, 2009), several respondents claimed that it would be a fundamental error to set incentives to reduce the price at which energy to cover losses is procured because this cannot be influenced by grid operators. Therefore, expressing reference values as relative values, e.g. percentage of energy distributed, seems better suited to provide a stable investment environment.

Lastly, several methodologies to determine the numerical value of these reference values can be found. A common approach is to monitor the evolution of losses overtime and set the reference values in such a way that progressive improvements are required from DSOs. This is the case, for example, in the UK or Portugal (OFGEM, 2009; Cossent et al., 2011). On the other hand, some regulators have opted for the application of different benchmarking tools to determine the level of efficient losses that is to be expected from the different DSOs. For instance, the NPAM has been used in Sweden to compute ex-post the energy losses that will be included into the revenue allowances of DSOs (ERGEG, 2008). Similarly, the Spanish RNMs have been used to define loss coefficients specific to each DSO that determine the reference value (called objective values in the Spanish regulation) (CNE, 2010; Cossent et al., 2011). Another example could be that of Norway, where energy losses are benchmarked across DSOs together with the remaining cost components included in the revenue allowances (ERGEG, 2008).

8.2 Setting incentives to reduce energy losses in the new environment

This section will firstly analyze how the penetration of DER and smart grid technologies can affect the distribution energy losses. Subsequently, several guidelines to determine the regulatory incentives for DSOs to reduce energy losses considering the upcoming changes will be discussed.

8.2.1 Impact of DER and smart grid technologies on distribution energy losses

The presence of DER in distribution networks can significantly change the power flow patterns. At the same time, this affects energy losses, particularly variable technical losses. Copper losses generally account for the highest share over total losses, which can range between 66% to 75% of total distribution losses (OFGEM, 2003; KEMA

Consulting GmbH, 2009)[56]. Therefore, the impact on energy losses of high penetration levels of DER should not be neglected when determining the associated regulatory incentives for DSOs.

In principle, the connection of DG units allows supplying demand with local generation resources. Thus, the distances at which electricity is transmitted diminish and energy losses are reduced. However, it has been shown that the effect of DG is not as straightforward to asses due to the influence of several variables comprising DG concentration, type of network, size and location of DG, DG penetration level or voltage control strategy (Chiradeja and Ramakumar, 2004; Méndez et al., 2006; Ochoa et al., 2006; Ochoa et al., 2008; González-Sotres et al., 2011). Moreover, many of the small-sized generators located at LV level are connected to a single phase, creating phase imbalances and increasing losses.

The general conclusion that can be drawn from all this research is that DG may indeed cause losses reductions, but only to the extent that DG is located close to consumption points and DG units produce during the same periods as energy is consumed. Therefore, very large DG penetration levels (generation exceeding local demand), DG located far away from consumers, or DG technologies whose production profiles do not match local consumption profiles can increase energy losses.

Demand side management is generally believed to lead to a reduction in losses. On the one hand, load curtailment and energy efficiency decrease overall consumption. On the other hand, since variable losses are proportional to the square of the current, load shifting from peak to valley hours also reduces distribution losses. Nonetheless, existing research has shown that energy losses may not be a major driver for demand response. For instance, (Shaw et al., 2009) estimate the value for DSOs of losses reduction through domestic load shifting. Their results show that energy losses indeed decrease although in such a small amount that the expenditures required are not justifiable in terms of losses reduction. In fact, several publications describing the benefits of demand side management do not even consider distribution losses as a relevant factor, focusing on generation costs, CO_2 emissions, and network investments (DOE, 2006; Strbac, 2008).

Nonetheless, significant losses reductions can be obtained under more extreme assumptions regarding consumers' elasticities, as in (Venkatesan et al., 2012). The results presented in this paper also show that demand response may even lead to an increase in losses due to a higher consumption during valley hours when electricity is cheaper. Hence, it can be concluded that the actual impact of demand response on energy losses will mainly depend on the extent to which consumption profiles are modified.

The relevance of demand response to reduce distribution losses may be enhanced if electric vehicles are widely adopted. Charging the batteries of PEVs constitutes an added load connected to the distribution grid, which is bound to cause an increase in energy losses. For instance, (Pieltain Fernandez et al., 2011) show that charging PEVs during off-peak hours results in a significant increment in energy losses at these periods, mainly because most PEVs were assumed to charge at off-peak hours to prevent incurring in additional investments. Nonetheless, the authors pose the need to perform more detailed time-domain simulation to attain a deeper understanding on the effect of PEVs. Several publications following this approach can be found (Peças Lopes et al., 2009a; Peças Lopes et al., 2009b; Clement-Nyns et al., 2010; Peças Lopes et al., 2011). All these

[56] These figures are not applicable to systems where commercial losses are very important, such as the aforementioned cases of Argentina and Brazil.

studies show that PEVs cause overall increases in energy losses, particularly in those areas which have reached a high penetration level. Nevertheless, coordinating the charging of PEVs, either through ToU tariffs or more advanced control strategies (aggregators, direct management from grid operator), can mitigate this increment[57].

In conclusion, it has been shown that DG and demand response have the potential to reduce energy losses in distribution networks, whereas PEVs are bound to cause the opposite effect. Nonetheless, this impact is only expected to become relevant once penetration levels reach high values. Moreover, existing research has found that the magnitude of this impact depends on a number of variables, many of which can vary significantly among distribution areas. Therefore, carefully analyzing the local conditions faced by each DSO is extremely relevant as DER penetration levels grow.

Smart grid technologies can also help DSOs reduce the energy losses in their networks thanks to a more intensive monitoring and automation. On the one hand, several operations conventionally carried out manually can be automated or extended to lower voltage levels and wider areas. For example, telecontrolling switching devices can facilitate network reconfiguration creating shorter paths to electricity flows and disconnecting transformers at night. Moreover, advanced voltage control strategies could be adopted by automating the connection and disconnection of capacitor banks and power electronic devices (presumably limited to HV levels), or by using DG in voltage control, either through power factor modulation or through direct voltage control. Nonetheless, these actions, even if they lead to a decrease in losses, are mainly motivated by quality of service concerns because their effect on losses is potentially limited.

The most important or immediate benefits of smart grids in relation with energy losses are those deriving from the enhancement of network monitoring and consumption metering. On the one hand, energy losses can be more accurately measured thanks to the implementation of smart metering. Actual meter readings could substitute different estimation methods used nowadays such as standard load profiles or simulation methods (ERGEG, 2008). Furthermore, AMR will allow DSOs to obtain metering information more easily avoiding the need to use meter readings from different periods in order to estimate the losses. Lastly, this enhancement of measurement accuracy will facilitate the estimation of non-metered supplies (e.g. public lighting) and detect illegal connections through local energy balances.

On the other hand, phase imbalances could be detected more easily so as to connect new consumers more efficiently. Nowadays, new consumers are generally connected to the phase with the lowest loading at the exact moment of connection. However, this phase is not necessarily the most lightly loaded on average. Therefore, network monitoring will allow distributing new consumers more evenly across phases, achieving lower energy losses.

However, it should be born in mind that smart distribution grids can lead to a more intensive use of the network capacity in order to defer or prevent onerous grid reinforcements. Consequently, distribution losses may increase due to the higher average loading of network components. Therefore, investment decisions should be made in such a way that the sum of the investment costs and the cost of losses is minimized throughout the lifetime of the assets.

[57] Coordinated charging is also intended to reduce other system costs such as variable generation costs or distribution network reinforcements. In fact, these aspects may be more important drivers than energy losses alone.

8.2.2 Adapting regulatory incentives to reduce energy losses to the penetration of DER and smart grid technologies

- **Smart grid technologies:**

The previous section has shown that, as compared to the case of continuity of supply, smart grid technologies would have a rather limited impact on the alternatives for DSOs to reduce energy losses. In many cases, the decrease in losses would be a by-product of measures to improve quality of service. Notwithstanding, it will indeed be possible to record more accurately the energy losses, including their variation during the day and throughout the year. This will not only allow DSOs to determine the actions that will yield the most cost-effective losses reductions by identifying the areas and periods with highest losses, but also will it allow regulators to implement more advanced regulatory incentives, e.g. by incorporating time-dependence. As discussed above, the latter issue is essential to make DSOs internalize the true cost of losses.

- **Incorporating the effect of DER on technical losses:**

Despite the fact that the variation of losses caused by DER cannot be directly controlled by DSOs, grid operators could be either rewarded or penalized as a result of the connection of DER. (de Joode et al., 2009) propose several alternatives to compensate DSOs for DG-driven costs, being energy losses among them; including revenue drivers or cost pass-throughs. Nevertheless, advanced regulatory frameworks should focus not only on compensating DSOs for incremental costs, but also on promoting efficiency. Since this cannot be achieved by means of the previous mechanisms, it is recommended to incorporate their impact of DER on energy losses into the methodologies used to determine the reference value of losses (Cossent et al., 2009).

Reference values are usually determined on the basis of DSO performance over a number of years, as done in UK or Portugal (ERSE, 2008; OFGEM, 2009). This approach seems reasonable as long as the allowed revenues are consistent with these reference values. Notwithstanding, the penetration of DER may diminish the suitability of historical values since these may not adequately reflect the presence of DER. The impact of DER, especially DG, can be much more relevant for DSOs operating small regions where, for instance, DG has growth rapidly due to favourable wind or solar irradiation conditions (Cossent et al., 2011). Therefore, alternative or complementary approaches are required.

For example, in the UK, a site-specific loss adjustment factor (LAF) is used to subtract the losses caused by large DG units connected in remote areas (OFGEM, 2009). Note that, strictly speaking, this LAF is not reflected in the reference values but correcting the level of observed losses. However, this approach does not truly internalize the actual effect of all DER, particularly any potential positive impact.

Another interesting example is that of Spain, where DSO-specific loss coefficients are used to determine the reference values for each DSO. These coefficients are computed by using RNMs which are capable of modelling the impact of DG (CNE, 2010; González-Sotres et al., 2011). However, since these models can only analyze a limited number of scenarios, accurate estimations of loss factors (ratio of average to peak losses) are necessary to estimate yearly losses. The uncoordinated charging of EVs and DG producing in off-peak periods would increase loss factors. On the contrary, demand response, coordinated EV charging and DG producing during peak hours would drive loss factors down. These effects can different for each distribution area. Hence, loss factors used in regulation may need to be fine-tuned.

Alternatively, the Norwegian approach based on benchmarking (black-box approach) losses together with the remaining cost components could be adapted by incorporating DER-related variables. Nonetheless, in order to avoid using a very high number of variables and the significant multicollinearity problems that may arise, it is required to identify the DER-related significant variables through testing several model specifications, performing second-stage regressions or factor analysis techniques. Some of the few studies that include DG (other DER are not deemed relevant nowadays) can be found in (Agrell and Bogetoft, 2007; Growitsch et al., 2012).

It can be concluded that incorporating the effect of DER on losses will presumably become more relevant. In fact several regulators have already implemented different approaches to do this. Nonetheless, further experience should be gained in order to identify potential improvements and best practices.

- **Measuring energy losses:**

The measurement of energy losses in the presence of DG also deserves some attention. The most straightforward precaution to be taken is to add the energy injected by DG into the distribution network to the electricity coming from the transmission network and connections with neighbouring DSOs when calculating the total electricity entering the distribution system. Otherwise, DG production would reduce the amount of energy entering the system and energy losses would be underestimated (Cossent et al., 2011) (even negative losses could be obtained). Note that the energy injected by EVs under V2G schemes would produce a similar effect. Additionally, very large DG concentrations may cause reverse power flows in some distribution networks during periods of high DG production. These should be measured as negative injections when computing the amount of energy distributed.

Furthermore, (Shaw et al., 2010) state that even when DG reduces the amount of physical energy losses in the distribution grid, DSOs could be penalized due to the existence of fixed losses which are not affected by DG. This could happen when the reference values are determined as a percentage of the energy consumed and DG is assumed to affect both the amount of losses and consumption. Under these conditions, DSOs would be penalized when DG reduces losses in a higher percentage than the reference value for losses. The authors illustrate this with an example taken from the UK's context. Assuming that fixed losses account for 30% of total losses and that these are 6.5% of energy consumption, the approximate reduction in losses caused by a DG unit producing 100kWh would be obtained as shown in (8-2).

$$\Delta Loss = (100\% - 30\%) \cdot 6.5\% \cdot 100kWh \approx 4.5kWh \tag{8-2}$$

On the other hand, assuming a reference value of losses of 5.48% (value corresponding to the DNO Electricity North West for the DPCR4) the reduction in the reference value for losses, expressed in units of energy, would be computed as follows (8-3).

$$Loss_{ref}^{wDG} = 5.48\% \cdot \left(E_{cons}^{woDG} - 100kWh\right) = 5.48\% \cdot E_{cons}^{woDG} - 5.48kWh \tag{8-3}$$

In the previous example, the DSO analyzed would be penalized even if DG has actually reduced energy losses due to the fact that energy losses have decreased to a lower extent than the reference value (4.5kWh versus 5.48kWh). Because of this, the authors in (Shaw et al., 2010) conclude that the incentives to reduce energy losses should be oriented in an input-based fashion to be more effective. Nonetheless, the drawbacks of input-based regulation previously addressed are not discussed in detail by the authors. Moreover, this would only occur when it is assumed that DG is reducing the volume of energy consumption that is metered, i.e. net-metering schemes relying on a single meter[58]. Hence, it is worth analyzing the conditions under which the previous analysis remains valid and potential alternatives in the design of incentive schemes that allow retaining an output based design.

In order to do this, a similar calculation has been carried out through an excel spreadsheet that computes the impact of DG of DSO revenues under different approaches to measure energy losses. Following similar implicit assumptions to those in (Shaw et al., 2010)[59], two situations with and without net-metering for DG are compared. The main differences are related to the measurement of energy consumption and energy injected into the distribution network, which will be used to compute the share of losses and the level of the incentives. These two situations are modelled as follows:

- With net-metering: the amount of energy consumed that is metered is equal to actual consumption minus DG production. The only energy injected that is seen is that coming from the upstream grid which is equal to the metered consumption plus the energy losses.
- Without net-metering: the amount of energy consumed that is metered is equal to the same consumption that would be metered in the absence of DG. The amount of energy injected is computed as the sum of the energy flowing from the upstream grid (metered consumption plus energy losses) and DG production.

Two different indicators of energy losses are computed: energy losses over energy consumption and energy losses over energy injection into the distribution grid. Accordingly, two different incentives have been calculated as shown in (8-4).

$$\begin{aligned} Inc_{cons} &= (Loss_{ref}^{out} - Loss_{meter}^{out}) \cdot E_{cons} \cdot Rate \\ Inc_{inj} &= (Loss_{ref}^{in} - Loss_{meter}^{in}) \cdot E_{inj} \cdot Rate \end{aligned} \tag{8-4}$$

Where:

$Inc_{cons/inj}$	Incentive computed on the basis of energy consumed/injected
$Loss_{ref/meter}$	Reference and metered value of energy losses
$E_{cons/inj}$	Yearly energy consumed/injected in the area operated by the DSO
Rate	Incentive rate set by the regulator

The input data used to calculate the previous indicators and incentives are provided in Table 8-1. For the sake of simplicity, it has been assumed that the reference value for losses presents the same numerical value regardless of whether energy losses are measures as a percentage of the energy input or output. Otherwise, it would have been necessary to modify this parameter for each scenario, depending on how DG modifies the metered level of energy injected and consumed, following equation (8-5). The main drawback of this assumption is that the values of the input based and output based

[58] An alternative would consist in the installation of two separate meters, one for the DG unit and another to record consumption. The network user would be charged according to the net consumption, but the disaggregated information could be used for other purposes such as the computation of the total energy injected to the grid.

[59] DG is located at the exact location of end-consumers and distributed proportionally to the demand of each consumer. Thus, it is possible to neglect the geographical distribution of load and demand when estimating variable energy losses. Moreover, the variation of losses over time is neglected for the sake of simplicity.

incentives and penalties calculated hereinafter are not consistent among them and, therefore, cannot be directly compared. Moreover, this reference value is kept constant regardless of the level of penetration of DG to allow for comparisons to be made. Nonetheless, as explained before, reference values should be adapted to account for the impact of DER on losses.

$$Loss_{ref}^{kWh} = Loss_{ref}^{in}(\%) \cdot E_{inj} = Loss_{ref}^{out}(\%) \cdot E_{cons} \tag{8-5}$$

Energy consumption [MWh]	5000
Energy losses wo DG of output	7%
Share of iron losses wo DG	30%
Reference value for incentive	7.5%
Incentive rate [€/MWh]	60
Energy displaced by DG [MWh]	200

Table 8-1: Input data for energy losses analysis

Firstly, it has been assumed that fixed losses remain constant whereas variable losses decrease proportionally to the energy that is produced by DG, i.e. losses are proportional to net demand. The latter assumption is not very realistic as variable losses tend to vary in proportion to the square of demand. However, this was assumed so as to allow comparability with the results in (Shaw et al., 2010).

The results obtained for a situation without DG and those obtained for the two different approaches to measure energy losses described above are shown in Table 8-2. It can be seen that the DSO can be indeed penalized (lower incentive) when net-metering is in place despite the fact that DG has caused a reduction in losses, regardless how energy losses are measured. This is because DG is not only reducing the energy losses, but also the level of demand that is recorded by the consumers' meters. Consequently, the share of losses will increase when the decrease in the amount of energy consumed/injected is higher than the decrease in losses as a result of DG offsetting demand. Whenever this happens, the incentive received by the DSO is lower than in the absence of DG.

	Without DG	Net-metering	Independent DG
Total losses [MWh]	350	340.2	340.2
Iron losses [MWh]	105	105	105
Copper losses [MWh]	245	235.2	235.2
Energy consumed metered [MWh]	5000	4800	5000
Net-energy consumed [MWh]	5000	4800	4800
Energy coming from upstream grid [MWh]	5350	5140.2	5140.2
DG injection measured [MWh]	0	0	200
Energy injected measured [MWh]	5350	5140.2	5340.2
Share of losses over energy consumed	7.00%	7.09%	6.80%
Share of losses over energy injected	6.54%	6.62%	6.37%
Incentive for DSO energy consumed [€]	1500	1188	2088
Incentive for DSO energy injected [€]	3075	2718.9	3618.9

Table 8-2: Impact of DG on the measurement of losses (variable losses proportional to load)

Therefore, the most relevant factor determining whether DG has a negative impact on the incentive paid to the DSO is the extent to which losses are reduced by DG. For instance, a high share of fixed losses causes a lower proportional reduction of total losses as compared to the energy consumed. Hence, the higher the weight of fixed losses, the more jeopardized the DSO will be. On the contrary, the greater the decrease in variable losses caused by DG, the better-off the DSO will be. In order to illustrate this, the same analysis was carried out considering that variable energy losses are proportional to the square of (net) demand (being constant the factor of proportionality, which could be interpreted as the grid equivalent resistance). The results obtained are summarized in Table 8-3.

	Without DG	Net-metering	Independent DG
Total losses [MWh]	350	330.792	330.792
Iron losses [MWh]	105	105	105
Copper losses [MWh]	245	225.792	225.792
Energy consumed metered [MWh]	5000	4800	5000
Net-energy consumed [MWh]	5000	4800	4800
Energy coming from upstream grid [MWh]	5350	5130.792	5130.792
DG injection measured [MWh]	0	0	200
Energy injected measured [MWh]	5350	5130.792	5330.792
Share of losses over energy consumed	7.00%	6.89%	6.62%
Share of losses over energy injected	6.54%	6.45%	6.21%
Incentive for DSO energy consumed [€]	1500	1752.48	2652.48
Incentive for DSO energy injected [€]	3075	3241.044	4141.044

Table 8-3: Impact of DG on the measurement of losses (variable losses proportional to the square of the load)

It can be seen that in this case the DSO would not receive a lower incentive despite attaining a reduction in losses. Nonetheless, the incentive perceived by the DSO under a net-metering scheme would always be lower than when DG is considered as an independent network user, assuming DG reduces energy losses in absolute terms. Note that this may not be the case when DG is not connected next to consumption points or load and generation profiles show important mismatches in time.

In order to analyze the effect of the remaining parameters, a sensitivity analysis was performed by varying the annual energy consumption, DG production, incentive rate, reference value and initial level of losses. The main outstanding interactions that have been observed are the following:

- Even though DSOs may not always be prejudiced by DG as compared to the scenario without DG, the incentive received by the DSO is always lower under net-metering than when DG is connected through a separate meter.
- Under the assumptions made, high DG penetration levels significantly reduce variable losses. However, under net-metering, this can increase the share of losses since iron losses become comparatively much more relevant. Furthermore, in some cases, the DSO can be penalized even if the share of losses does not increase as compared to the no-DG scenario. This is because the difference between the reference value and measured losses is multiplied by a much lower amount of energy distributed. None of this happens when DG is metered independently.
- If the initial levels of losses without DG are rather low, the negative effect of DG for the losses incentive for DSOs under net-metering becomes greater. This is due to the fact that DG attains scarce benefits in terms of losses reduction, as these are very low,

whereas the amount of consumption metered is significantly reduced. The same effect is observed for high values of the reference value.

In conclusion, it can be said that the connection of DG under a net-metering scheme relying on a single meter can have a negative impact on the incentives received by DSOs to reduce energy losses, even if actual losses decrease. This negative impact is particularly noticeable when the share of fixed losses is high, DG penetration rate increases, the initial level of losses without DG is very low or the reference value for losses is high as compared to the actual initial share of losses without DG.

In order to prevent this from happening, it is recommended to meter DG production independently from consumption. Note that this does not necessarily rule out net-metering as a viable scheme since a two-meter configuration is possible. Being this the case, consumers would pay an energy charge according to the net energy consumption, and a fixed charge according to the maximum net power consumed to pay for the network and other tariff components. Besides providing a much more reliable measure of distribution losses, this approach would present other advantages such as avoiding the problems related to charging only volumetric charges, DG and cost recovery. Detailed discussions about volumetric charges and stand-by rates for DG (charges per kW) in the US can be found in (Casten, 2003; Morrison, 2003; Casten and Karegianes, 2007; Goulding and Bahçeci, 2007). An alternative solution would consist in setting the incentive reference values in absolute term, i.e. in units of energy. However, DSOs may face uncertainties over future demand, thus discouraging investments in losses reduction.

8.3 Summary and conclusions

Energy losses can be defined as the difference between the energy entering the distribution network and the energy flowing out of it. This difference can be driven by two very different causes. On the one hand, the term commercial losses is used to refer to losses that result from their incorrect measurement due to meter failures, theft or non-metered supplies. On the other hand, technical losses are caused by physical phenomena through which electricity is dissipated as heat or noise in grid components. Under normal circumstances, commercial losses generally correspond to a low share of total losses.

Energy losses do not constitute a direct cost for DSOs in an unbundled environment since these agents do not sell, purchase or produce electricity. Nonetheless, regulation focuses on the distribution side because most of energy losses occur at this level of the power supply chain and because DSOs are the ones with the capabilities to reduce them. Consequently, similarly to the case of continuity of supply, incentive schemes intend to make DSOs internalize the cost of losses. In fact, the theoretical framework described in the previous chapter concerning continuity of supply is immediately applicable to the regulation of energy losses. Hence, the optimal level of losses would be such that minimizes the total cost of reducing losses and the cost of losses for consumers.

Additionally, some of the practical considerations previously described are also relevant in this context. Notwithstanding, energy losses incentives can be much simpler since the value of losses for consumers can be assumed to be independent on the level of losses, thus being enough with linear incentive schemes. Moreover, the value of losses itself can be indexed to energy prices and CO_2 emissions, which are generally public data. Lastly, the occurrence of losses does not directly impact consumers. Thus, contrary to quality of service, the concept of worst-served consumers is not relevant. This makes minimum standards or premium quality contracts unnecessary. Furthermore, incentive schemes do not need to incorporate a geographical differentiation. It is only the total amount of losses that matters. However, due to the variation of electricity prices and emissions over time, incorporating a temporal differentiation in losses incentive schemes is particularly important to adequately reflect the value of losses.

The penetration of DER can substantially modify power flow patterns throughout the distribution grid. DG and demand response can potentially reduce energy losses, although this depends to a great extent on several factors that may change from one DSO to another. Moreover, EV charging may constitute a significant added load at MV and, especially, LV level. The effect of EVs can be particularly important if battery charging is not coordinated due to the increase in the peak load. As a result, DSOs could be penalised (or rewarded) due to factors outside their control. Therefore, the reference values for losses embedded in incentive schemes should incorporate the effect of DER in order to mitigate these problems while encouraging DSOs to do their share in the reduction of energy losses. Several approaches can be followed for this, such as modelling DER in engineering models or adding losses as an output variable in black-box benchmarking models. Further research and experience is needed to identify improvements to existing practices and develop detailed guidelines.

New technologies can also affect how DSOs seek to reduce technical energy losses by offering them new possibilities. Nevertheless, it is the enhanced grid monitoring and advanced consumption metering that can affect more deeply the regulation of energy losses thanks to a more accurate measurement of energy losses. In countries with a large share of commercial losses, smarter distribution grids have the potential to help tackle this problem. Furthermore, better information about how much, when and where technical losses occur can substitute current approximations based on standard load profiles or connectivity models and allow the implementation of more advanced incentive schemes, e.g. by implementing further time differentiation.

A final aspect that ought not to be neglected is what indicator regulators should use to measure losses. Energy losses are generally measured as a percentage of the energy injected into the distribution grid (input) or as a percentage of electricity consumption (output). This is because, in case losses were measured in absolute terms (kWh) or in economic terms (monetary units), DSOs would be exposed to the full uncertainties over demand behaviour or electricity prices. Since DSOs cannot control these two elements, this should be avoided. However, even this recommended approach could lead to some problems as DG penetration rates increase. DG can create a paradoxical situation in which DG reduces actual losses but increases the share of losses, thus having a negative impact on the incentives received by DSOs to reduce energy losses.

It has been shown that net-metering relying on a single meter could jeopardize DSOs as the level of measured losses can increase in spite of the fact that actual physical losses decrease. This happens due to the fact that DG would not only reduce the amount of losses but also the amount of energy injected or consumed from the network. This effect is particularly noticeable when the share of fixed losses is high, DG penetration rate increases, the initial level of losses without DG is very low or the reference value for losses is high as compared to the actual initial share of losses without DG. In order to avoid this problem, it is advisable to have separate meters for DG and loads. Nevertheless, this does not necessarily prevent the implementation of net-metering schemes because a two-meter configuration is possible. Doing this, consumers would pay an energy charge for the net energy consumption and a fixed tariff component according to the peak net demand.

Main conclusions:

- Energy losses are not a direct cost for unbundled DSOs. Therefore, incentive schemes are necessary to include the cost of losses into DSO decisions
- Linear incentive rates are sufficient because the value of losses for consumers can be assumed to be independent on the level of losses. Moreover, minimum standards or premium quality contracts and a geographical differentiation are unnecessary. On the other hand, a temporal differentiation in losses incentives is particularly important
- The reference values for losses in incentive schemes should incorporate the effect of DER. Several approaches for this have been discussed. Nonetheless, further research and experience is needed to identify required improvements to existing practices
- Enhanced grid monitoring and advanced metering that can deeply affect energy losses regulation thanks to a more accurate measurement of energy losses that allows implementing more advanced incentive schemes and losses mitigation strategies
- Measuring losses in absolute terms (kWh) or in monetary units exposes DSOs to the full uncertainties over demand or electricity prices. This is not advisable because DSOs cannot control these two factors
- Under net-metering with a single meter, DG can create a paradoxical situation in which DG reduces actual losses but increases the share of losses due to the reduction in the amount of energy distributed measured. Therefore, it is proposed to implement net-metering schemes with a two-meter configuration

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9. Conclusions, original contributions and future work

Power sector deregulation and liberalization introduced competition in the generation level and, in some cases, in the retailing level as well. Nevertheless, network activities, i.e. transmission and distribution, remained subject to economic regulation due to their being considered as natural monopolies. The main goal of regulation is to encourage efficiency to attain lower tariffs for end consumers while ensuring the financial viability of regulated firms and adequate levels of quality of service. However, the existence of strong asymmetries of information between the regulator and network companies creates important difficulties.

Nowadays, incentive regulation has become a popular way to regulate distribution companies, usually referred to as DSOs in a European context. Despite the fact that several different approaches can be found, the main common feature is that the firms' revenues are decoupled from their actual costs for a number of years. Hence, DSOs may retain the difference should they manage to reduce their costs. The effects of incentive regulation seem to be positive according to existent empirical evidence. However, distribution networks are currently experiencing profound changes driven by technological developments and the transformation of distribution network users.

Energy sector decarbonisation has driven growing penetration levels of distributed energy resources (DER). DER mainly comprises small sized generators connected at distribution level (DG), but may also include other distribution network users such as electric vehicles, controllable loads or storage units. The penetration of DER at a large scale produces significant effects on distribution networks, which require the adaptation of conventional operational and planning practices. Therefore, smarter distribution grids are nowadays considered necessary in order to efficiently integrate DER whilst providing the quality of service level required by distribution network users. Nonetheless, this transition will not be possible to achieve in an efficient and effective manner without an appropriate regulatory framework.

Addressing this need, this thesis has presented an in-depth revision of the practices and methods for the economic regulation of electricity DSOs and evaluated their suitability for the new context. This last chapter summarizes the contents of the thesis and its main conclusions. Furthermore, the actual new findings and contributions are presented to illustrate the relevance of the work done. Finally, the chapter identifies some potential future lines of research that can result from the thesis developments.

9.1 Summary and conclusions

Economic regulation of electricity distribution: a paradigm shift

The thesis started with a review of the conditions under which the regulatory intervention is required to protect end consumers from monopolistic behaviour. It was shown that electricity distribution broadly complies with the characteristics of natural monopolies and that the increasing uncertainties over the technologies and demand faced by DSOs hamper the implementation of alternatives to economic regulation. As the basis of subsequent discussions, the theoretical and practical approaches to the economic regulation of natural monopolies, and electricity distribution in particular, were reviewed. It was seen that, supported on theoretical developments, incentive regulation has been widely applied in electricity distribution, although there are still important challenges to tackle information asymmetries, especially when regulating long-lived network investments.

Distribution networks are experiencing a transformation characterized by the penetration of new technologies and the changes in the type and needs of grid users. Existing studies state that this process can have a significant impact on the distribution grid, which create additional and manifold challenges both to DSOs and regulators. This document has particularly focused on the implications for the economic regulation of DSOs, showing that it is needed to revisit the processes and tools used to determine the allowed efficient revenues as well as the determination of regulatory incentives related to energy losses and quality of service. The goal is to provide DSOs with incentives to innovate and efficiently integrate DER. In the early stages, specific incentives may be necessary, as the ones currently in place in several countries. Notwithstanding, in the long-term, a regulatory framework that removes regulatory uncertainties and provides a stable environment for investments will be required.

In order to prevent disruptive changes, any regulatory amendment should be implemented starting from today's regulation. Revenue cap was taken as a reference for subsequent analyses because it is more suitable to encourage the adoption of energy efficiency measures and DG. Distribution networks are characterized by an extremely large number of individual potential investment alternatives in distribution networks. This intrinsic feature greatly hampers the determination and evaluation of the efficient level of costs, especially network investments, required to accommodate load growths, replace aged assets or improve quality of service. Information asymmetries can be mitigated through the use of certain tools and through appropriate regulatory incentives. The first group mainly comprises regulatory accounting, and benchmarking, whereas the regulatory incentives that can be used for different purposes include bonus-malus systems, ex-ante/ex-post mechanisms such as sliding scale of profit sharing schemes, revenue drivers, cost pass-through, etc.

Regulatory benchmarking in electricity distribution

Regulatory benchmarking plays an increasingly important role in the evaluation of the efficiency of DSOs, which is a central step in the determination of allowed revenues. Consequently, many distinct approaches have been developed over the years to meet the needs of regulators. Notwithstanding, in spite of the several attempts to classify the different benchmarking methods, inconsistencies among the different classifications were found. It was found that scarce attention has been paid to the categorization of reference methods, presumably due to the fact that, contrary to frontier methods, these models are almost tailor-made. A new comprehensive taxonomy of benchmarking methods for electricity distribution was proposed. According to the intrinsic characteristics of the techniques applied and the assumptions required, two main groups were identified: black-box benchmarking and reference benchmarking. Frontier benchmarking methods stand out within the former group, whereas norm models represent the main reference benchmarking method.

Both types of benchmarking approaches show different origins. Black-box methods originated from theoretical developments in the fields of operations research and econometrics intended to evaluate the productivity of any activity in a general way. On the other hand, reference methods arise from the practical difficulties of evaluating efficient distribution network investments with conventional models. Existing surveys suggest that some form of reference benchmarking is used much more frequently than suggested by the reduced number of publications available on this subject.

This is also reflected in the fact that the pros and cons of the different black-box approaches, especially frontier methods, have been analyzed in detail in the literature. However, reference methods have rarely been compared with other methods or among them. Due to the lack of available information about reference benchmarking methods, quantitative comparisons could not be carried out. Therefore, only qualitative comparisons could be performed. Firstly, the differences and similarities of the Swedish NPAM and the Spanish RNMs were discussed. It was concluded that, contrary to what it is usually done, norm models are not a homogeneous group. In general, the Swedish NPAM generally performs stronger simplifications as compared to the Spanish RNMs, albeit this allowed reducing the computational burden. Nonetheless, the comparison of frontier methods versus norm models is particularly interesting, as there is usually very little interaction between economists (frontier methods) and engineers (reference methods), despite the fact that regulators require the knowledge of both groups.

The simplicity of frontier methods reduces the regulatory burden, facilitates price reviews and allows for easier replication of the results. Moreover, they can take into account all costs in a single analysis, reflect the historical evolution of actual grids and do not face technical limitations related to the size of the distribution area. However, the model specification and the number of observations have a strong influence on the results obtained. Furthermore, their more important limitation is that they generally fail to adequately account for the heterogeneity in the environmental conditions faced by DSOs, which can be enhanced as a result of the transition towards smarter distribution grids and the large-scale connection of DER. Consequently, they may not be fully suitable to determine DSO investment needs.

On the contrary, norm models require extensive resources to be developed and maintained. As a result, this can hamper third-party participation and lead to opaque regulatory processes. Additionally, norm models are limited to the analysis of those aspects directly related to the network. Therefore, additional analyses are usually required and some cost tradeoffs can be neglected. Nevertheless, the detailed modelling of network and load conditions represents a significant advantage of norm models when evaluating investment requirements.

In conclusion, both approaches can be useful for regulators as they present complementary characteristics. Hence, the synergies of both approaches could be further explored by regulator. Notwithstanding, norm models or other forms of reference benchmarking will presumably become more frequently used in order to assess investment requirements, especially to account for the penetration of DER and new technologies. It should be remarked that any benchmarking tool is imperfect and its results cannot be directly translated into revenue allowances. In any case, some discretionary decisions from the regulator will always be required. In fact, practical experience suggests that the way benchmarking tools are applied within a more general remuneration framework can be at least as important as the selection of the benchmarking model. In the end, the situation in each country or region (number of firms, regulator's know-how, practices in neighbouring countries, etc.) will influence the most suitable method to implement.

Regulating distribution network investments and determining allowed revenues

Owing to the aforementioned importance of the overall regulatory framework design, this thesis has also proposed a suitable framework for the determination of the allowed revenues of DSOs with uncertain demand and technology. The general remuneration framework was reviewed; nonetheless, the emphasis was placed on the process to set the new investments included in the DSOs' remuneration. The price review was organized into four successive steps: i) determination of the opening RAB, ii) calculation of new investments and OPEX allowances, iii) definition of the remuneration formula and ex-ante annual revenue allowances, and iv) ex-post adjustment based on actual costs incurred.

The opening RAB is used to determine the CAPEX allowances, both depreciation and return on assets, during the whole regulatory period. Consolidating the RAB is considered the best alternative to provide regulatory certainty. Nonetheless, the lack of reliable or suitable information frequently forces regulators to perform an in-depth evaluation of the asset base. Several methods ranging from book value to new replacement value can be found. In the end, the most suitable alternative would depend upon each specific context and the information available about the DSOs' assets and cost accounting.

As mentioned above, a revenue cap formula has been selected since this is considered to be better adapted to the characteristics of the electricity distribution sector. The proposed implementation presents the particularity that the X factor is computed as a smoothing factor instead of an efficiency factor because this approach allows more flexibility when defining the revenue path and avoids large fluctuations in cash flows. This contributes to the creation of regulatory stability and certainty and a favourable investment environment.

The central mechanism proposed in this thesis is the use of an incentive compatible menu of contracts to determine new investment requirements. The main objective is to set ex-ante revenue allowances so that DSOs are encouraged to reduce costs (moral hazard problem), and perform ex-post corrections in order to prevent excessive deviations between costs and revenues (adverse selection problem). The ex-post adjustment is made following predefined rules, thus mitigating regulatory uncertainties. Additionally, DSOs are encouraged to provide accurate and justified information about their investment needs. This method is not innovative in itself as it has already been used in the UK. Notwithstanding, this thesis has provided clear guidelines to easily construct such matrices and discussed in detail the regulatory implications of each parameter involved as well as the conditions which ensure incentive compatibility. This discussion, which was missing in the literature, can facilitate the diffusion of such mechanism.

The Spanish context was used as a case study to illustrate the applicability of the proposed regulatory framework. The major shortcomings identified in current Spanish regulation are related to the uncertainty that stems from the absence of a RAB, annual ex-post reviews and opaque regulatory decisions. Consequently, investments have stagnated despite the fact that distribution costs have increased. Aiming at overcoming these problems, several recommendations specific to the Spanish case were proposed.

Firstly, it was considered necessary to re-assess the RAB, at least for the first regulatory period, as the regulator apparently does not possess reliable information. A hybrid approach between reproduction cost, based on inventories, and new replacement value, computed with a greenfield RNM, was considered to be suitable for the Spanish context. Following the idea of relative reference networks, the relative weight of both estimations depends on the gap between the reproduction and the replacement values as compared across DSOs. Thus, some form of yardstick competition is introduced among them. On the other hand, the menu of contracts could be easily implemented in Spain as DSOs already submit periodical investment plans to the regulator. What is more, the incremental RNM already in use can be a powerful tool to help estimate the regulator's forecast for investment requirements.

Hence, the proposed approach builds on the overall current regulatory process, thus avoiding large disruptions. Additionally, the uncertainties created by frequent ex-post reviews are mitigated and DSOs participate in a more transparent way. Moreover, the smoothing X factor creates a more stable and predictable remuneration, which facilitates the task of reducing the tariff deficit in Spain over the next few years. Lastly, the burden on the regulator is decreased by removing annual investment revisions that required extensive analyses with the RNMs.

Incentives to improve continuity of supply

Incentive regulation created the need to complement revenue allowances with additional incentive schemes to prevent DSOs from reducing costs at the expense of quality of service. More specifically, economic regulation mainly addresses continuity of supply, measured through the number and duration of the interruptions suffered by end consumers, due to the strong relation of this quality dimension with the investment and maintenance expenditures of DSOs. The goal of these regulatory incentives is to make DSOs internalize the cost of interruptions for consumers so that their decisions are taken accordingly. Ideally, the optimal level of quality, in which the total social costs are minimized, ought to be pursued.

The main instrument to encourage DSOs to improve continuity of supply is usually a bonus-malus incentive scheme, where one or more reliability indices are used to measure quality levels. This thesis has shown that the optimal level of quality can be theoretically attained through two kinds of incentives, either with linear or non-linear incentive rates. However, the implementation of any of these schemes faces significant practical limitations. Most importantly, the cost curves reflecting the cost of interruptions for consumers and the costs incurred by DSOs to improve quality levels, on which the optimal incentive design is based, are unknown and change over time and across regions. The consumers' cost curve has been extensively analyzed and several methodologies have been developed for its estimation. On the contrary, distribution expenditures needed to improve continuity levels have been rarely studied, mainly because it is virtually impossible to define a sharp border between quality-driven costs and load-driven costs.

In order to mitigate the impact of these limitations, mechanisms to account for uncertainties such as deadbands or caps and floors are frequently set. Additionally, it is necessary to incorporate a differentiation across regions to account for the differences in marginal continuity improvement costs. Last but not least, the interaction between overall revenue allowances and continuity incentives should be carefully analyzed. Continuity of supply incentives should not be considered as a stand-alone mechanism, but a complement to the overall revenue determination process that prevent the deterioration of quality. Hence, the reference values for continuity levels set by the regulator should be consistent with the reference remuneration. Quality integrated cost benchmarking is essential to achieve this.

The penetration of smart grid technologies and DER also affects the regulation of continuity of supply. On the one hand, this thesis has analyzed how new network technologies can affect the optimal level of quality. The results obtained show that technological developments may not only attain more cost-effective quality improvement, thus increasing the socially optimal level of quality; but also allow DSOs to reach higher levels of reliability than what was possible with previous technologies. The effectiveness of different technologies strongly depends on the characteristics of the network and the technology costs. Moreover, smart metering technologies could enhance a more detailed and accurate measurement of supply interruptions, especially at lower voltage levels. This in turn would allow regulators to implement more advanced incentive schemes.

On the other hand, DER penetration implies that new types of network users are being connected to the distribution system. However, conventional reliability indicators were focused exclusively on consumers. Therefore, these indicators and the incentive schemes based on them neglect the presence of other network users such as DG units. The consequence of this is that DSOs would not take into account the presence of DG when defining their strategies for reliability improvement, despite the fact that DG is indeed jeopardized by supply interruptions. This thesis has proposed to incorporate the presence of DG in the measurement of continuity of supply and has analyzed several indicators suitable both for linear and non-linear incentive schemes.

Linear incentives have been analysed by evaluating several reliability indices both considering only end consumers and considering both consumers and DG in an aggregate way. The results clearly showed that the measured level of continuity, for the same number and duration of interruptions, can vary significantly when incorporating DG. This effect depends on the relative location and concentration of DG units within the network. Accounting for DG in non-linear incentives would require estimating function of the cost of energy non-produced or ENP, which resembles the concept of ENS for consumers. This function would be added to the cost of ENS to obtain the total cost of interruptions for distribution network users. The cost of the ENP would be indexed to electricity prices and DG-RES support payments, whereas the expected amount of ENP could be estimated through representative generation profiles for each DG type or through actual measurements.

Incentives to reduce energy losses

In addition to continuity incentives, DSOs are frequently encouraged to reduce energy losses through similar bonus-malus mechanisms. DSOs are the key agents in energy losses reduction. However, they would not normally make efforts to reduce losses as they do not constitute a direct cost for them. The relevant theoretical framework for setting these incentive schemes would be the same than the one applied for quality of service. However, this thesis has shown that important differences can be found in practice, making losses incentives simpler to implement. Firstly, the value of losses for consumers can be assumed to be independent on the level of losses, thus avoiding complex non-linear incentives. Secondly, this value can be indexed to public data such as market prices. Lastly, the concept of worst-served consumers and the geographical location of consumers are not relevant. Hence, additional mechanisms such as minimum standards or premium quality contracts are unnecessary.

The penetration of DER can substantially modify power flows and energy losses in the distribution grid. As a result, this can affect DSO revenues, either positively or negatively, for something completely out of their control. In order to prevent this, reference values for losses should reflect the impact of DER. This can be done, for instance, by modelling DER in engineering models or adding losses as an output variable in black-box benchmarking models. The most relevant effect of smart grid technologies on energy losses regulation is a more accurate measurement, substituting approximations based on standard load profiles or connectivity models with actual records. Furthermore, more advanced incentive schemes can be implemented, for example by including further time differentiation in reference values.

Lastly, the suitability of different indicators to measure losses was analyzed. Generally, losses are measured as a percentage of the energy injected into the distribution grid (input) or as a percentage of electricity consumption (output). In case losses were measured in absolute terms, either in kWh or in monetary units, DSOs would face the uncertainties over demand and prices which they cannot control. Moreover, DG connected under net-metering with a single meter can lead to an increase in the share of losses even if actual losses are reduced, because the amount of energy injected or consumed also decreases. This is particularly noticeable when the share of fixed losses is high, DG penetration rate increases, the initial level of losses without DG is very low or the reference value for losses is high as compared to the initial share of losses. These problems can be avoided by implementing net-metering schemes with separate meters for DG and loads.

9.2 Original contributions

The development of this thesis has yielded several original contributions to the current knowledge about the regulation of electricity DSOs. These are summarized below:

i. Several authors have raised the question as to whether electricity distribution should keep being subject to economic regulation instead of introducing competition, either in the market or for the market. Chapter 2 (section 2.1) contributed to this discussion by a detailed analysis of the changes driven by the penetration of DER and smart grid technologies. It was concluded that economic regulation will still be needed, although DSOs should be encouraged to interact more actively with other agents such as aggregators, active consumers or DG units to attain a more efficient distribution grid planning and operation.

ii. Another relevant contribution of this thesis is the new taxonomy proposed in chapter 4 (section 4.2) to classify the existing benchmarking methods for electricity distribution. The review of existing taxonomies revealed that inconsistent criteria were being used and several gaps existed, particularly concerning reference benchmarking approaches. Hence, new classification criteria and a comprehensive study of the different reference methods were incorporated in the new taxonomy.

iii. The use of an incentive compatible matrix to regulate distribution investments in the UK has drawn considerable attention as an innovative and beneficial regulatory approach. However, the lack of clear guidelines to construct such a matrix constituted a significant barrier to replicate this mechanism. This gap was addressed in chapter 5 (section 5.2.2.2) of this thesis. Therein, the parameters involved in this process were identified, their regulatory implications clarified and simple non-iterative formulas to obtain them were developed.

iv. Chapter 5 (section 5.3) also presented a relevant thesis contribution with detailed proposals to amend current Spanish distribution regulation so as to eliminate the existing regulatory uncertainties and create a more favourable environment to attract investments. The central recommendation was to implement the incentive compatible menu system building on current regulatory practices.

v. It was found that regulators usually resort to some form of reference benchmarking in practice due to the limitations of black-box methods when estimating network investment needs. However, existing literature focuses almost exclusively on the application of black-box methods, particularly frontier benchmarking methods. In order to build bridges between both approaches, chapter 6 (section 6.3.2) of this thesis presented a comparison of the main pros and cons of reference network models versus black-box benchmarking and identified certain complementarities.

vi. Regarding the theoretical framework for the regulation of quality of service, previous works had already introduced the concept of the optimal level of quality and defined how to set linear incentives so as to attain such a quality level. Chapter 7 (7.2.2.1) of this thesis has made a contribution by showing that non-linear incentives may also attain this optimal level of quality and discussing the differences in terms of strength of the incentives perceived by DSOs and the distribution of social benefits among DSOs and consumers.

vii. The regulation of continuity of supply will be affected by the penetration of new technologies. In order to analyse the effect of technology development on the definition of these incentives, chapter 7 (section 7.4.1) performed quantitative analyses showing that both the optimal level of quality and the maximum feasible level of quality can change as new technologies are introduced. Moreover, it was shown that network conditions (topology, undergrounding, load density, etc.) are key to determine the magnitude of these changes.

viii. Reliability is nowadays measured exclusively as the impact of power interruptions on electricity consumers. However, DG units, which are increasingly being connected to distribution systems, are also affected by interruptions. Chapter 7 (section 7.5) shows how conventional practices may lead to suboptimal investment and operational decisions. Therefore, developing new ways to measure and regulate continuity of supply accounting for the presence of DG is deemed necessary. This thesis has discussed how this can be done both with linear and non-linear incentive schemes.

ix. Previous publications had already identified the fact that DG may lead to an increase in the share of losses in spite of reducing actual losses, thus negatively affecting DSO revenues. However, the conditions under which this could happen were unclear. Thus, chapter 8 includes a comprehensive discussion about how to measure energy losses in the presence of DG and the potential effect of different net-metering schemes. This discussion is particularly relevant since net-metering is mentioned as the way forward for some DG-RES technologies in some European countries (e.g. Spain), especially solar PV.

9.3 Publications

The thesis developments and original contributions have been presented in the following publications.

Journal papers:

- R. Cossent, T. Gómez, P. Frías, "Towards a future with large penetration of distributed generation: Is the current regulation of electricity distribution ready? Regulatory recommendations under a European perspective", *Energy Policy*. vol. 37, no. 3, pp. 1145-1155, March 2009.
- P. Frías, T. Gómez, R. Cossent, J. Rivier, "Improvements in current European network regulation to facilitate the integration of distributed generation", *International Journal of Electrical Power & Energy Systems*. vol. 31, no. 9, pp. 445-451, October 2009.
- D. Trebolle, T. Gómez, R. Cossent, P. Frías, "Distribution planning with reliability options for distributed generation", *Electric Power Systems Research*. vol. 80, no. 2, pp. 222-229, January 2010.
- L. Pieltain, T. Gómez, R. Cossent, C. Mateo, P. Frías, "Assessment of the impact of plug-in electric vehicles on distribution networks", *IEEE Transactions on Power Systems*. vol. 26, no. 1, pp. 206-213, February 2011.
- R. Cossent, L. Olmos, T. Gómez, C. Mateo, P. Frías, "Distribution network costs under different penetration levels of distributed generation", *European Transactions on Electrical Power*. vol. 21, no. 6, pp. 1869-1888, September 2011.
- R. Cossent, T. Gómez, L. Olmos, "Large-scale integration of renewable and distributed generation of electricity in Spain: current situation and future needs", *Energy Policy*. vol. 39, no. 12, pp. 8078-8087, December 2011.

Conference papers:

- R. Cossent, T. Gómez, L. Olmos, C. Mateo, P. Frías, "Assessing the impact of distributed generation on distribution network costs", *6th International Conference on the European Energy Market - EEM'09*. pp. 586-593, Leuven, Belgium, 27-29 May 2009.
- L. Olmos, T. Gómez, E. Lobato, R. Cossent, "Policy and Regulatory Changes for T&D networks to facilitate the integration of high shares of Wind, PV and CHP in the Supply system", *10th International Association for Energy Economics European Conference (IAEE): "Energy, Policies and Technologies for Sustainable Economies"*. Vienna, Austria, 7-10 September 2009.
- R. Cossent, L. Olmos, T. Gómez, C. Mateo, P. Frías, "Mitigating the impact of distributed generation on distribution network costs through advanced response options", *7th Conference on the European Energy Market - EEM10*. ISBN: 978-1-4244-6838-6, Madrid, Spain, 23-25 June 2010.
- R. Cossent, T. Gómez, J. Peças, "Does distributed generation require new regulatory tools? A comparative analysis of distribution network regulation in Spain and Portugal", *17th Power Systems Computation Conference - PSCC'11*. Stockholm, Sweden, 22-26 August 2011.
- R. Cossent, "Setting regulatory incentives for continuity of supply in smart distribution grids", *3rd IEEE PES Innovative Smart Grid Technologies (ISGT)*. Berlin, Germany, 14-17 October 2012.

Additionally, the following working papers are under preparation aiming at their potential future publication.

Working papers:

- R. Cossent, T. Gómez. "Revisiting the case for the economic regulation of electricity distribution".

- R. Cossent, T. Gómez. “Regulatory benchmarking in electricity distribution: a comprehensive taxonomy of approaches”.
- R. Cossent, T. Gómez. “Regulatory benchmarking in electricity distribution: reconciling frontier methods with engineering approaches”.
- R. Cossent, T. Gómez. “Implementing incentive compatible menus of contracts to regulate electricity distribution investments”.
- R. Cossent, T. Gómez. “Incorporating distributed generation into the regulatory incentives to improve continuity of supply in distribution networks”.

9.4 Future lines of research

The outcomes of this thesis have permitted the identification of new lines of research that could be interesting to explore in future works. Similarly, due to the need to limit the scope of the thesis, some lines of research could not be explored in detail. This section intends to summarize the most important of these and highlight their relevance.

- A straightforward continuation of the work presented in this thesis would consist in implementing the formulas developed to build an incentive compatible matrix of regulatory contracts. Spain would be an obvious candidate country owing to the implementation guidelines provided for this country in the thesis. Should it be applied to a different context, the major differences would presumably be found in the methodology to determine the regulator’s revenue estimation.
- In order to determine the additional income that ensures incentive compatibility in the menu matrix, only a linear and a quadratic functions were analyzed in detail in order to prevent iterative calculations. Notwithstanding, future research could investigate new formulas and analyse their implications in terms of economic incentives for DSOs.
- An efficient integration of DER will require DSOs to interact actively with other agents, for example by contracting out ancillary services from DG units, active consumers, aggregators, etc. Nonetheless, further research is still needed to identify these services and define the most suitable mechanisms: local markets, grid codes, etc.
- DER should also become active players within the distribution grid. Therefore, in addition to the aforementioned mechanisms to provide ancillary services, they should also perceive appropriate economic signals that encourage and more grid-friendly behaviour. Hence, future research is needed to develop methodologies to compute connection and use of system charges for DER. Additionally, research is also needed to understand the appropriate mechanisms to foster demand response and active customer participation (for which economic signals alone may not be enough).
- Further work is needed to explore how frontier benchmarking and reference benchmarking could be jointly used by regulators in price review processes, either to set comparisons or using each model for a different purpose. This knowledge would allow exploiting the synergies between both approaches.
- Additional quantitative studies about the marginal costs of improving continuity of supply in distribution networks are necessary. Several issues could be explored. For instance, evaluating the extent to which expenditures to improve quality can

be separated from load-driven costs would provide useful insights into how to set consistent revenue allowances and continuity incentives. Moreover, assessing the correlation between the reduction in the number of interruptions and their duration, which are usually assumed to be independent variables, could allow regulators to implement more effective incentive schemes.

- More detailed distribution reliability indicators that account for the presence of DG could be developed building on the thesis developments. Furthermore, it would be necessary to define precise implementation strategies. For example, regulators could start by monitoring only these indicators and introducing the new indices progressively in incentive schemes.
- After the implementation of smart metering, it should be evaluated how to improve the measurement of continuity of supply and how to incorporate these new measurements to the detection of failures in distribution network components.
- Similarly to the case of continuity of supply, future studies should evaluate the costs of reducing energy losses at distribution level. The separability of these costs with other expenditures should also be analyzed to define incentives that are consistent with revenue allowances.
- Regulators should study how the measurements recorded by smart meters can substitute other approximate models, such as standard load profiles, in the quantification of energy losses at low voltage level. More accurate estimations are to be expected, especially concerning the temporal distribution of losses, thus enhancing more effective losses reduction strategies from DSOs.

A. Additional descriptions of frontier benchmarking methods

This annex provides further details about the review of existing frontier benchmarking methods presented in Chapter 4, section 4.3.1.3.

A.1 Variations of non-parametric models

i) **Environmental variables** are those that influence the performance of the firms but are not controllable by these. The most common environmental variables are those related to geography, climate, characteristics of demand or ownership. There are several alternatives to deal specifically with environmental variables. A possible approach is to estimate separate frontiers for each different subgroup of the sample according to the environmental variables and compare each one of these frontiers with the overall frontier to measure the influence of the exogenous factors. Alternatively, the optimisation problem can be modified by adding an extra constraint for each environmental variable as shown in (A-1), where each variable *e* corresponds to an environmental variable (Banker and Morey, 1986). Note that the treatment is similar to that of remaining inputs without multiplying the efficiency and the value of the input[60]. Finally, regressions can be performed on the results of DEA using the environmental factors as explanatory variables. Several models with different complexities can be found in the literature, from two-stage model with second-stage tobit regressions, to four-stage models. All these models result in the correction of the efficiency rates initially estimated (see (Fried et al., 1999) and (Nillesen and Pollitt, 2008) for an overview). These are sometimes referred to as semi-parametric models (Simar and Wilson, 2007)[61].

$$
\begin{aligned}
&\min \theta_0 \\
&s.t. \\
&\theta_0 \cdot x_{i_0} - \sum_{j=1}^{n} \lambda_j \cdot x_{ij} \geq 0; \quad \forall i \\
&-y_{r_0} + \sum_{j=1}^{n} \lambda_j \cdot y_{rj} \geq 0; \quad \forall r \\
&x_{e_0} - \sum_{j=1}^{n} \lambda_j \cdot x_{ej} \geq 0; \quad \forall e \\
&\lambda_j \geq 0 \quad \forall j
\end{aligned}
\qquad \text{(A-1)}
$$

ii) It was previously mentioned that non-parametric methods could be either input or output based. Technical efficiency would thus be measured through radial efficiency measures, i.e. either input or output distance functions. However, these two types of radial distance functions would be particular cases of the broader **directional distance functions** (Färe and Grosskopf, 2000). In radial distance functions, it is assumed that either outputs are to be maximised or inputs are to be

[60] This would be a particular case of a directional distance function, which will be explained next.

[61] The reader should be aware that the term semi-parametric models may be used to refer to very different models, that is parametric models where the assumptions on the distribution properties of some parameters are relaxed. See, for instance, (Greene, 2008).

minimised. On the other hand, with directional distance functions, it is assumed that both effects can take place to increase efficiency, either in all the variables or in certain pre-specified variables. Mathematically, this is solved by multiplying all the "controllable" inputs and outputs (called directional vectors) by the efficiency estimate in the corresponding constraints. These directional vectors must be chosen by the model developer (Färe and Grosskopf, 2000). Directional distance functions were firstly developed for convex frontiers (DEA), although they were later applied to non-convex frontiers (FDH), as in (Cherchye et al., 2001).

iii) An additional criticism to the conventional radial distance functions proposed by (Farrell, 1957) is that strong efficiency is not attained; i.e. a firm may be considered as efficient despite the fact that inputs could be further reduced (in an input based model). This is the same as saying that not all the slacks associated with the constraints related to the inputs and outputs are null. **Additive models** can be used to overcome this shortcoming (Cooper et al., 2007). Some additional advantages of additive models are that they remove the need to choose between an input or output oriented approach or that the model is transitional invariant, thus allowing for the use of non-positive inputs and outputs (Banker et al., 2004). This latter issue will be addressed below in more detail.

The additive model is formulated from the standard DEA model by removing the efficiency rate θ from the constraints and substituting the objective function by the maximisation of the sum of slacks associated with each of the constraints. This objective function is shown in (A-2), where s_{i} and s_r are the slacks associated with the input and output constraints respectively. This is equivalent to maximising the sum of the input reduction and output increase. A firm would be efficient in an additive model only if and only if all slacks are zero (Cooper et al., 2007).

$$\max \sum_{i=1}^{m} s_i^- + \sum_{i=1}^{s} s_i^+ \qquad \textbf{(A-2)}$$

iv) The **multiplicative model** was originally proposed by (Charnes et al., 1982). The constraints are the weighted products of inputs and outputs, being the weights exponents to the different inputs and outputs, as shown in (A-3). This problem can be formulated as a linear optimisation problem by taking logarithms. Multiplicative models are very rarely applied in practice, although (Banker et al., 2004) state that they present certain advantages such as the fact that they are not limited to concave efficiency frontiers or that they can be used to obtain quantitative estimates of elasticities, i.e. how a change in one variable affects others.

$$\begin{aligned}
&\min \theta_0 \\
&s.t. \\
&\theta_0 \cdot x_{i_0} - \prod_{j=1}^{n} x_{ij}^{\lambda_j} \geq 0 \quad \forall i \\
&-y_{r_0} + \prod_{j=1}^{n} y_{rj}^{\lambda_j} \geq 0 \quad \forall r \\
&\textstyle\sum_{j=1}^{n} \lambda_j = 1; \quad \forall j \\
&\lambda_j \geq 0 \quad \forall j
\end{aligned} \qquad \textbf{(A-3)}$$

v) The meaning of **translation invariance** has been mentioned before. This refers to the fact that zero or negative inputs can be dealt with by the model. On the other hand, **unit invariance** refers to the fact that the results of the model do not depend on the units used for the model variables. For example, the energy delivered by an electricity distribution company could be inputted in kWh or in MWh. Both characteristics are desirable properties of models used to assess the efficiency of certain firms. However, (Knox Lovell and Pastor, 1995) argue that the models conventionally used do not comply with both conditions. Even the DEA model by (Charnes et al., 1978) is not fully unit invariant, despite the fact that the efficiency estimate is unit invariant, as the slacks do depend on the units selection. Thus, (Knox Lovell and Pastor, 1995) propose new normalised weighted models that comply with these two conditions.

vi) Conventional formulations of DEA (and FDH) assign all the firms in the frontier a 100% efficiency rate. Therefore, it is not possible to sort efficient firms among them. The **super efficiency** model proposed by (Andersen and Petersen, 1993) avoids this problem. The main idea is to develop a frontier for each firm in such a way that each DMU is compared to a weighted linear combination of the remaining DMUs, i.e. excluding the specific DMU under evaluation from the sample. Thus, efficiency rates higher than one would be obtained for efficient firms. Comparing these super efficiencies, it is possible to sort efficient firms as well as inefficient ones. A DEA-CRS super efficiency model is shown in (A-4), where k is the DMU under evaluation.

$$
\begin{aligned}
&\min \theta_k \\
&s.t. \\
&\theta_k \cdot x_{i_k} - \sum_{\substack{j=1 \\ j\neq k}}^{n} \lambda_j \cdot x_{ij} \geq 0; \quad \forall i \\
&-y_{r_k} + \sum_{\substack{j=1 \\ j\neq k}}^{n} \lambda_j \cdot y_{rj} \geq 0; \quad \forall r \\
&\lambda_j \geq 0 \quad \forall j
\end{aligned}
\tag{A-4}
$$

vii) One of the major drawbacks of estimating non-parametric frontiers lies in the fact that statistical analysis cannot be done with the efficiency results. This is important as the frontier is estimated from actual observations and may be subject to biases and sampling errors. This presents relevant regulatory implications as not only the bias would benefit all the firms analysed, but also the benefit is not evenly distributed among the firms (Agrell and Bogetoft, 2007). In order to address this shortcoming (Simar and Wilson, 1998) proposed a **bootstrap** methodology that provide a bias corrected efficiency estimate and allows to obtain confidence intervals for the efficiency estimates. Similarly, (Simar and Wilson, 2007) proposed a **double bootstrap** procedure to be applied in two-stage semi-parametric models.

viii) The standard non-parametric frontier benchmarking methods are deterministic. Consequently, they are very sensitive to statistical noise (e.g. measurement errors) in the inputs and outliers (Ruggiero, 2004). In order to increase the robustness of efficiency estimates, several approaches have been developed. (Simar, 2007) provides a review of the existing approaches, which shows that some authors have proposed methods to filter input data in order to detect outliers and remove them before running non-parametric methods. However, these methods may work well with outliers, but fail to deal with the statistical noise. Therefore, other authors have proposed proper **stochastic DEA** methods (SDEA) that are based on the use of panel data, chance constrained programming or some parametric assumptions about the distribution of the noise. (Simar, 2007) assesses the properties of the existing models and make new proposals to overcome the deficiencies detected. This work has been subsequently extended in (Simar and Zelenyuk, 2011).

The previous review does not include an alternative approach to dealing with noise in non-parametric frontier estimators. **Fuzzy DEA or FDH** (FDEA or FFDH) has been proposed as an alternative to SDEA methods. In FDEA, the model variables are given as fuzzy numbers. (Hatami-Marbini et al., 2011) perform a comprehensive review of the existing literature on fuzzy non-parametric frontier estimation and propose a taxonomy for the existing approaches based on five categories: tolerance, α-level, fuzzy ranking, possibility and other developments.

A.2 Formulation of the parametric MOLS benchmarking model

Hereinafter, the MOLS method proposed by (Schmidt, 1976) is presented.

Let us assume that equation (A-5) is the production or cost function for a specific firm i, where the parameters α and β are obtained through an OLS estimation and u is the error term (inefficiency plus noise) corresponding to firm i. It is assumed that the error term is independently and identically distributed with a mean $E(\varepsilon_i)$ and standard deviation σ.

$$y_i = \alpha + \sum \beta \cdot x_i - \varepsilon_i \qquad \textbf{(A-5)}$$

The parameter β is unbiased, but α is not. However, by making the transformation shown in equation (A-6), the new error term u_i^* would have a mean of zero and a standard deviation of σ. Under these conditions, the OLS estimators are unbiased.

$$y_i = (\alpha - E(\varepsilon_i)) + \sum \beta \cdot x_i - u_i^* \qquad \textbf{(A-6)}$$

However, the true value of the mean inefficiency of firms ($E(\varepsilon_i)$) is unknown. Notwithstanding, it can be estimated by maximum likelihood (ML) provided that it is assumed that the error terms (ε_i), which measure the inefficiency of a firm, follow a certain (one-sided) probability distribution; e.g. an exponential or a half-normal distribution. The residuals of the OLS regression (e_i) can provide consistent estimates of the variance or higher moment measurements of the error terms (ε_i) since the function is translated through a constant (Bottasso and Conti, 2011). Thus, if the mathematical relationship between the expectation of the residuals ($E(\varepsilon_i)$) and the variance or higher moment measurements for the assumed probability distribution is known, it is possible to estimate $E(\varepsilon_i)$. For instance, as shown in (A-7), if we assume that the residuals follow an exponential distribution, the standard deviation of the residuals is a consistent estimator of the expected value of the residuals. Then, this value ($\sigma(e_i) = \hat{E}(\varepsilon_i)$) would be added to the constant term of the OLS function.

$$
\begin{aligned}
&f(x) = \lambda \cdot e^{-\lambda \cdot x} \\
&E(X) = \frac{1}{\lambda} \\
&V(X) = \frac{1}{\lambda^2} \Rightarrow \sigma(X) = \frac{1}{\lambda} = E(X)
\end{aligned}
\qquad \textbf{(A-7)}
$$

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B. Additional descriptions of the Spanish and Swedish norm models

This annex provides further details about the Spanish RNMs and the Swedish NPAM presented in Chapter 4, section 4.3.2.1.2.

B.1 Spanish RNMs

Input data

- **Network users (loads, DG, EVs, etc.):** for every user, the geographical coordinates, voltage level at the point of connection, power (consumed or generated) and power factor must be provided. Since the existence of DG and EVs may require considering more than one scenario to design the reference network, e.g. peak demand and peak generation, RNMs can manage several load scenarios.
- **Transmission substations:** RNMs do not optimize the location of transmission substations as this is generally out of the control of DSOs. Therefore, the location and capacity of these substations must be provided as an input to the models.
- **Library of standardized network components:** RNMs make investment decisions on the basis of a library of standard components. This library comprises: HV power lines, MV and LV feeders, HV/MV substations, MV/LV transformers, protection equipment, maintenance crews, capacitor banks and voltage regulators. Whenever necessary, these elements must be differentiated per voltage level, type of area and whether they are built overhead or underground. Several data ought to be provided for each one of the possible network components. These comprise investment and maintenance costs, rated capacity, electrical properties such as impedances, and useful life. Moreover, in order to compute the expected reliability indices it is necessary to provide the models with failure rates, repair times, and a standard annual duration of preventive maintenance actions that are carried out on each type of component, for overhead and underground elements and in each kind of area.
- **Other modelling parameters:** In addition to the previous information, RNMs need various parameters in order to perform all the computations involved. The most relevant ones are: simultaneity factors (explained below), economic parameters (cost of energy losses, WACC, etc.) and load modelling and GIS related parameters (expected load growth, density and minimum number of consumers to classify them into different areas and identify settlements, degree of undergrounding required within settlements per voltage level, street maps parameters). In addition to capacity constraints, the RNMs must observe the maximum and minimum bus voltages and the limits imposed on reliability of supply indices. The RNMs described in this report use the TIEPI and NIEPI indices, which are very similar to ASIDI and ASIFI respectively (IEEE, 2001). Distinct continuity requirements are set for each type of distribution area.
- **Data for the initial network:** this information ought to be provided to the expansion-planning RNM. This must include the topological as well as the electrical data for the existing network. Furthermore, the initial network users and the incremental ones, either horizontal growths (new points of supply/generation) or vertical growths

(variations in the power demanded/generated by existing network users), must be differentiated.

Internal processes

The previous input data are used according to the steps explained hereinafter. Some of these steps, such as the deployment of electrical equipment, are common to all voltage levels, whereas other may only be applied to a specific voltage level, e.g. the continuity of supply stage.

a) **DG/Loads modelling:** at this stage cities/towns are identified and consumers are classified into five categories: urban, sub-urban, concentrated rural, scattered rural and industrial areas. This classification is carried out according to the load density and number of customers of each kind (HV, MV or LV). This affects different aspects such as continuity of supply requirements for the consumers located in each type of area or whether overhead or underground lines are built. Additionally, the street maps within densely populated areas are automatically generated.

b) **Build topological grid:** at this point an optimal network layout is computed. This topological network takes into account geographical constraints such as forbidden ways through, orography, street maps and, in the case of the expansion-planning RNM, the topology of the initial network. All geographical constraints except for street maps are external inputs to the models. The topology of initial MV and LV grids is radial. Nonetheless, the final MV grid is only determined after reliability or continuity of supply is taken into account in a subsequent stage. On the other hand, the initial HV network is designed according to an N-1 reliability criterion, i.e. every load and substations must be supplied through at least two paths. At this stage, possible infeasibilities in future steps are avoided by means of a simplified preliminary electrical test.

c) **Deployment of electrical equipment:** this stage involves assigning to each segment or node of the topological network an optimally sized network element (line, transformer, etc.) by running a power flow for the network users given as input. At this step, technical constraints such as voltage and capacity limits are considered. Different power flow algorithms are used for HV meshed networks and MV/LV radial networks. The use of simultaneity factors at both ends of HV/MV substations and MV/LV transformers involves that the power entering one voltage level is not equal to the power supplied by the remaining voltage level. This requires modifying the modelling of these elements for power flow calculations. Details are provided in (Mateo Domingo et al., 2011).

d) **Continuity of supply:** the final stage is focused on reinforcing the MV grid to meet the continuity of supply constraints, defined in terms of maximum allowable values for TIEPI and NIEPI. The failure rates of network elements are aggregated to compute the frequency of interruption of every load. Fault location and repair times are simulated taking into account the location (urban or rural) and type of network (overhead or underground). As a result, additional equipment comprising normally open meshing feeders, circuit breakers, maintenance crews, or fault detectors may be placed to improve continuity levels if needed.

Dealing with geographical constraints

Within settlements, actual distribution networks must be built following the streets since they cannot cross buildings or parks. If necessary, electrical lines may cross the streets, mainly in large avenues, perpendicularly to the road. RNMs mimic this behaviour.

Settlements and street maps are endogenously detected and generated based on the number and density of consumers. Lines are forced to follow these street maps as shown in Figure B-1, where blue triangles represent the HV/MV substations and yellow squares the MV/LV transformers. Thick black lines represent the MV feeders and thin green lines correspond to the approximate street map automatically generated.

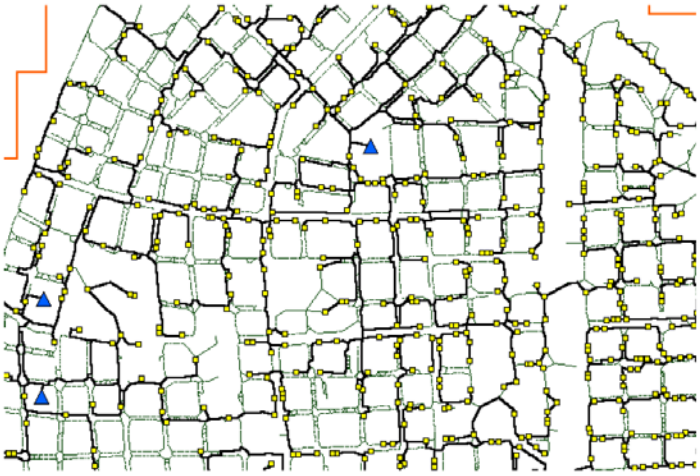

Figure B-1: Distribution network design following street maps (Gómez et al., 2012)

(Mateo Domingo et al., 2011) presents an assessment of the impact of street maps on the length of the distribution networks. In order to perform this analysis, an urban area serving above one million consumers was planned by the green-field RNM. Results showed that, for the same distribution area, the LV grid calculated by the RNMs was 16.8% longer when street maps were considered. On the other hand, the length of the MV network obtained increased by 37.5% as compared to the situation where street maps are not considered. Naturally, this will have a significant impact on the distribution network costs.

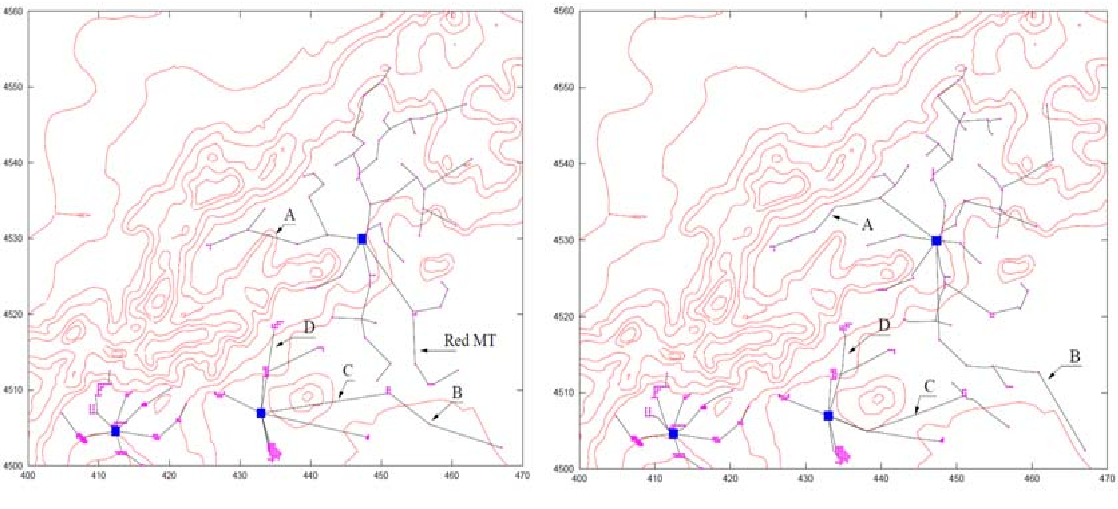

Figure B-2: Distribution network design considering orography (Gómez et al., 2012)

Outside densely populated areas, distribution networks must observe some geographical constraints as well. For example, electrical lines cannot cross certain regions such as protected natural areas, rivers or seas. These regions can be considered by RNMs by introducing the geographical coordinates of the vertexes of polygonal lines containing these forbidden regions. Furthermore, orography may also influence the design of distribution networks. Therefore, RNMs can interpret raster maps so as to avoid and skirt mountains or steep regions. Figure B-2 displays two reference networks obtained for the same distribution area with and without considering geographical constraints. It can be seen that some lines have been modified and consumers transferred to a different feeder so as to avoid mountains (line C) or steep areas (lines A and B). Contrary to street maps, environmental factors must be introduced exogenously to the models.

B.2 Swedish NPAM

Input data

The required data comprise the following:

- **Consumers and DG:** for every single consumer, the geographical location, maximum power demanded, energy consumption profile and voltage level ought to be provided. Moreover, the location of DG units as well as their capacity and voltage level is required. Finally, data regarding the aggregation of power consumption, which is similar to the concept of simultaneity factor, are necessary.
- **Connections to neighbouring grids:** the points of connection to the grids of other DSOs or TSOs must be given as an input. Thus, their geographical location, their voltage level and the energy delivered to the DSO network are necessary.
- **Lines and transformers:** the limitations in terms of size, length, voltage drop or capacity of network components are inputs to the NPAM. Furthermore, a standard investment cost function should be provided.
- **Reliability:** in order to assess the reliability of the reference networks, the average frequency and duration of interruptions, differentiated into planned and unplanned outages, are used. Additionally, an estimation of the cost of interruptions for consumers is required to value in economic terms these interruptions.
- **Energy losses:** energy losses are estimated according to a certain loss function given as input. Electricity market prices are used to value energy losses.
- **Economic parameters:** in order to compute the annuity of investment costs, some economic parameters are necessary, such as depreciation times and interest rates.

Reliability assessment

The expected reliability of the reference network with spare capacity is calculated following five steps:

i) The starting point, the attained reliability and the associated cost is calculated from the actual statistics provided by the network companies and estimations of the cost of interruptions for single consumers. The latter data were taken from a survey carried out among Swedish consumers, whose results are shown in Figure B-3. The resulting costs of interruptions were computed as the maximum cost reported in the aforementioned survey times the mean power consumption of each consumer and the duration of the interruptions they suffer.

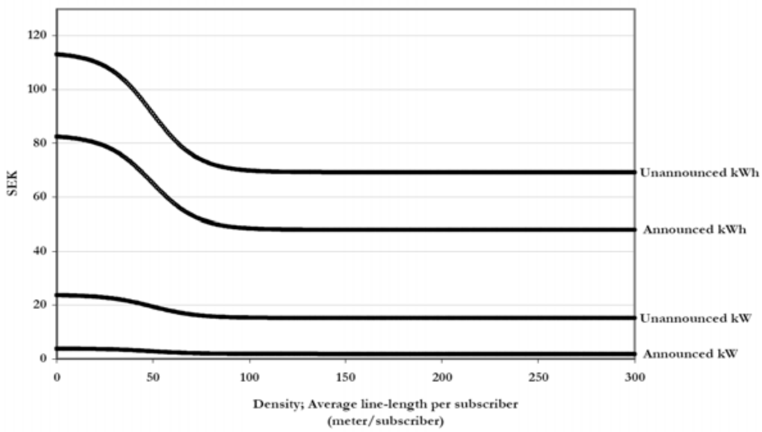

Figure B-3: Outage cost for electricity consumers in Sweden (Larsson, 2005)

ii) Next, a reliability assessment of the expected quality obtained by the radial network is performed through a Monte Carlo simulation. The probability distribution functions for failures in the network elements depend on the type of asset and the voltage level. The location of protection equipment is assumed as given in such a way that a failure in any network element can be appropriately isolated, keeping the upstream network from the point of failure unaffected.

iii) The third step consists of adding additional feeders to the reference grid ordered by profitability, i.e. those feeders that more rapidly reduce the cost of interruptions are installed first. As a simplification, these spare lines are not dimensioned as it was done for the radial grid. This is done until the cost of adding a new feeder is higher than the cost of outages.

iv) Subsequently, the Monte Carlo method is used to simulate the failure of transformers. This allows the model to estimate the cost deriving from these failures. Additional transformers are placed where it is economical to double the transformer, i.e. installing a spare transformer in parallel, as compared to the cost of its failure.

v) Finally, after all the spare capacity has been calculated and added to the reference network, a new reliability assessment is performed through a Monte Carlo simulation similarly to the second step. This results in the calculation of the expected outage cost.

References

Gómez, T., C. Mateo, Á. Sánchez, P. Frías and R. Cossent (2012). Reference Network Models: a computational tool for planning and designing large-scale smart electricity distribution grids, in High-Performance Computing in Power and Energy Systems. Ed. S. K. Khaitan, A. Gupta, S. Aluru and K. Gopalakrishnan, Springer Verlag.

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Mateo Domingo, C., T. Gomez San Roman, A. Sanchez-Miralles, J. P. Peco Gonzalez and A. Candela Martinez (2011). "A Reference Network Model for Large-Scale Distribution Planning With Automatic Street Map Generation." Power Systems, IEEE Transactions on 26(1): 190-197.

C. Mathematical derivation of how to compute the matrix of menu of contracts

This annex provides further details about the computation of the additional income in a matrix of incentive compatible menus of contracts. These mathematical derivations are intended to support the formulas presented in Chapter 5, section 5.2.2. Firstly, the formulas proposed in chapter 5 to compute the ex-ante allowed revenues and the sharing factor are presented again for the sake of completeness. Next, this annex turns to the derivation of the formulas to compute the additional revenue.

Ex-ante allowed revenues: determined as a weighted sum of the estimates provided by regulator and DSOs estimates, as shown in equation (C-1). The regulator would have to set the weighting parameter.

$$AR = \omega \cdot 100 + (1-\omega) \cdot Ratio \qquad \text{(C-1)}$$

Where:

AR	Allowed revenues, as percentage of the regulator's estimation [%]
ω	Weight given to the revenue estimation of the regulator [pu]
$Ratio$	Ratio of the DSO's estimation over the regulator's estimation [%]

Sharing factor: computed as a linear function of the DSO/Regulator ratio as shown in (C-2). The regulator would have to fix the reference value (sharing factor when the regulator and the DSO estimates are the same) and the slope of the linear function (how the power of the efficiency incentive is mitigated as the DSO's estimate increases).

$$SF = SF_{ref} + (Ratio - 100) \cdot SF_{roc} \qquad \text{(C-2)}$$

Where:

SF	Sharing factor
SF_{ref}	Reference value for the sharing factor (value for a *Ratio* of 100)
SF_{roc}	Slope or rate of change of the sharing factor with *Ratio*

Additional income: computed as a function of the DSO/regulator ratio. In principle, there is not a single type of function that allows attaining incentive compatibility. Hereinafter, how to compute the corresponding formula will be presented.

For the matrix to be incentive compatible, the maximum value for each row must be attained at the point where actual expenditures equal the DSO/Regulator ratio. Each element of the matrix can be computed as shown in (C-3).

$$Matrix_{element} = (AR - Exp) \cdot SF + AI \qquad \text{(C-3)}$$

Where:

AI	Additional income, calculated as a function of *Ratio*
Exp	Actual DSO expenditures included under the menu system, as percentage of the regulator's estimation [%]

The maximum value will be at the point where the 1st order derivative with respect to the DSO/Regulator ratio is zero. The conditions that the additional income must fulfil can be obtained by substituting the allowed revenues and the sharing factor by their expressions in (C-1) and (C-2) respectively and calculating the derivative with respect to *Ratio* of the function obtained. The resulting function is shown in (C-4) and its derivative in (C-5).

$$\begin{aligned} Matrix_{element} &= (1-\omega)\cdot SF_{roc}\cdot Ratio^2 + (200\cdot\omega\cdot SF_{roc} + SF_{ref} - 100\cdot SF_{roc} - \omega\cdot SF_{ref} - \\ &- SF_{roc}\cdot Exp)\cdot Ratio + 100\cdot\omega\cdot SF_{ref} - 10^4\cdot\omega\cdot SF_{roc} - SF_{ref}\cdot Exp + 100\cdot SF_{roc}\cdot Exp + AI \end{aligned} \quad \textbf{(C-4)}$$

$$\begin{aligned} &2\cdot(1-\omega)\cdot SF_{roc}\cdot Ratio + 200\cdot\omega\cdot SF_{roc} + SF_{ref} - 100\cdot SF_{roc} - \omega\cdot SF_{ref} - \\ &- SF_{roc}\cdot Exp + \frac{\partial AI}{\partial Ratio} = 0 \end{aligned} \quad \textbf{(C-5)}$$

a) Additional income as a linear function of the DSO/Regulator ratio

Let us assume that *AI* is a linear function of the DSO/Regulator ratio ($a + b\cdot Ratio$). Being this the case, the 1st order derivative of the additional income would be constant value *b* independent of the ratio (C-6).

$$\frac{\partial AI}{\partial Ratio} = b \quad \textbf{(C-6)}$$

The maximum should be at the point where actual expenditures coincide with the value of the DSO/Regulator ratio. Hence, in order to obtain the expression for the additional income parameters, the variable *Ratio* is substituted by the variable *Exp* in (C-5). The resulting expression is presented in (C-7).

$$\begin{aligned} &2\cdot(1-\omega)\cdot SF_{roc}\cdot Exp + 200\cdot\omega\cdot SF_{roc} + SF_{ref} - 100\cdot SF_{roc} - \omega\cdot SF_{ref} - \\ &- SF_{roc}\cdot Exp + b = 0 \end{aligned} \quad \textbf{(C-7)}$$

Additionally, this condition should be met for any value of the actual expenditures. Therefore, the factor that is multiplying the variable *Exp* in the expression obtained should always be equal to zero. This yields the condition shown in (C-8).

$$SF_{roc}\cdot(1-2\cdot\omega) = 0 \quad \textbf{(C-8)}$$

This condition can only be satisfied in case the parameter SF_{roc} were null or the parameter ω were equal to 0.5. The former option does not make sense for this problem, whereas the latter would in practice limit significantly the flexibility of this regulatory scheme. Consequently, it can be concluded that it is impractical for the additional income to be computed as a linear function of the DSO/Regulator ratio.

b) Additional income as a quadratic function of the DSO/Regulator ratio

Introducing the derivate with respect to the DSO/Regulator ratio of the quadratic function in (C-9), i.e. (C10), into equation (C-5), (C-11) is obtained.

$$AI = AI_{\text{int}} + \alpha\cdot Ratio + \beta\cdot Ratio^2 \quad \textbf{(C-9)}$$

$$\frac{\partial AI}{\partial Ratio} = \alpha + 2\cdot\beta\cdot Ratio \quad \textbf{(C-10)}$$

$$\begin{aligned} &2\cdot((1-\omega)\cdot SF_{roc} + \beta)\cdot Ratio + 200\cdot\omega\cdot SF_{roc} + SF_{ref} - 100\cdot SF_{roc} - \omega\cdot SF_{ref} - \\ &- SF_{roc}\cdot Exp + \alpha = 0 \end{aligned} \quad \textbf{(C-11)}$$

The maximum should be at the point where actual expenditures coincide with the value of the DSO/Regulator ratio. Hence, in order to obtain the expression for the additional income parameters, the variable *Ratio* is substituted by the variable *Exp* in (C-11), obtaining (C-12).

$$\left((1-\omega)\cdot 2\cdot SF_{roc}+2\cdot\beta-SF_{roc}\right)\cdot Exp+200\cdot\omega\cdot SF_{roc}+SF_{ref}-100\cdot SF_{roc}-\omega\cdot SF_{ref}+\alpha=0 \quad \textbf{(C-12)}$$

Moreover, this condition should be met for any value of the actual expenditures. Therefore, the factor that is multiplying the variable *Exp* in (C-12) should always be equal to zero. The expression obtained (C-13) yields the value of the parameter β as a function of the sharing factor slope and the weight of the regulator's estimate previously defined.

$$\beta=SF_{roc}\cdot(\omega-0.5) \quad \textbf{(C-13)}$$

Solving the rest of equation (C-12) for alpha, the second condition for the additional income formula can be attained (C-14).

$$\alpha=SF_{ref}\cdot(\omega-1)+100\cdot SF_{roc}\cdot(1-2\cdot\omega) \quad \textbf{(C-14)}$$

In order to check that the point obtained is indeed a maximum and not a minimum, it is necessary to check that the 2^{nd} derivative of (C-4) with respect to the ratio, presented in (C-15), is negative (C-16).

$$2\cdot(1-\omega)\cdot SF_{roc}+\frac{\partial^2 AI}{\partial Ratio^2}=2\cdot(1-\omega)\cdot SF_{roc}+2\cdot\beta \quad \textbf{(C-15)}$$

$$2\cdot SF_{roc}\cdot(1-\omega)+2\cdot\beta<0 \quad \textbf{(C-16)}$$

Introducing (C-13) in (C-16), the condition in (C-17) is obtained, which is an intrinsic characteristic of the menu regulation.

$$SF_{roc}<0 \quad \textbf{(C-17)}$$

As shown by the previous derivation, incentive compatibility can be achieved for any value of the intercept in the additional income formula, provided that the other parameters are computed as described above. This parameter, when defined as in (C-9) does not have any relevant meaning for regulatory purposes; it would merely be the value of the additional income for a null value of the DSO/Regulator ratio. Therefore, it was proposed in chapter 5 to let the regulator set a reference value that corresponds to the value of the additional at the point where the ratio is 100. The intercept of equation (C-9) would then be obtained as a function of the previous parameters by solving (C-18) when α and β are substituted by their expressions (C-14) and (C-13) respectively. Doing this, (C-19) is obtained.

$$AI_{ref}=AI_{\text{int}}+\alpha\cdot 100+\beta\cdot 100^2 \quad \textbf{(C-18)}$$

$$AI_{\text{int}}=AI_{ref}-100\cdot SF_{ref}\cdot(\omega-1)+10^4\cdot SF_{roc}\cdot(\omega-0.5) \quad \textbf{(C-19)}$$

D. Detailed results for reliability analyses

This annex provides further details about the results obtained in the reliability analyses presented in Chapter 7, section 7.4.1.

D.1 Rural feeder

	Configuration number	SAIFI	SAIDI [h]	Consumers costs [€]	DSO costs [€]	Total social costs [€]
Technology cluster 1	1	7.50	30.00	180,469	727	181,196
	2	5.63	22.50	135,352	1,454	136,806
	3	4.75	18.78	113,017	2,054	115,071
	4	3.88	15.06	90,683	2,654	93,337
	5	3.00	11.34	68,348	3,254	71,603
	6	2.63	9.75	58,777	3,854	62,631
	7	2.25	8.16	49,205	4,454	53,659
	8	1.88	6.56	39,633	5,054	44,687
Technology cluster 2	9	1.50	6.00	36,094	2,636	38,729
	10	1.13	4.50	27,070	3,363	30,433
	11	0.95	3.76	22,603	3,483	26,086
	12	0.78	3.01	18,137	3,603	21,739
	13	0.60	2.27	13,670	3,723	17,392
	14	0.53	1.95	11,755	3,843	15,598
	15	0.45	1.63	9,841	3,963	13,804
	16	0.38	1.31	7,927	4,083	12,009
	17	1.13	4.50	27,070	3,086	30,156
	18	0.45	1.54	9,293	3,356	12,648
	19	7.50	26.81	161,822	920	162,741
	20	1.50	5.36	32,364	2,828	35,192
	21	5.63	20.25	122,189	2,609	124,798
	22	1.13	4.05	24,438	4,517	28,955
	23	5.63	20.16	121,641	1,647	123,287
	24	1.13	4.03	24,328	3,555	27,883
	25	1.88	6.19	37,439	6,209	43,648
	26	0.38	1.24	7,488	8,117	15,605
Technology cluster 3	27	7.50	24.75	149,756	1,724	151,480
	28	5.63	19.88	119,995	2,451	122,446
	29	3.00	10.97	66,155	4,251	70,406
	30	1.88	6.19	37,439	6,051	43,490
	31	5.63	18.56	112,317	3,448	115,765
	32	3.00	9.66	58,477	5,248	63,724
	33	1.88	6.00	36,342	7,048	43,390
	34	1.50	4.95	29,951	3,348	33,299
	35	1.13	3.98	23,999	4,075	28,074
	36	0.60	2.19	13,231	5,875	19,106
	37	0.38	1.24	7,488	7,675	15,162
	38	1.13	3.71	22,463	5,071	27,535
	39	0.60	1.93	11,695	6,871	18,567
	40	0.38	1.20	7,268	8,671	15,940

Table D-1: Detailed result for the reliability analyses in the rural feeder

Table D-1 contains the detailed results obtained for the 40 configurations analysed for the rural feeder in section 7.4.1.1. More specifically, the table provides the SAIFI and SAIDI reliability indices resulting from each configuration (note that the values for ASIFI and ASIDI respectively are exactly the same because loads are evenly distributed across the feeder), the resulting cost of interruptions for consumers computed through the formula presented in chapter 7, the costs of the devices installed in each configuration and the total social costs (computed as the sum of the previous two quantities). The 11 non-dominated solutions of this case study are shadowed in grey.

		Configuration number	Consumer cost	DSO cost	Total social cost
Cluster 1	Maximum quality	8	39.633	5.054	44.687
	Optimal quality	8	39.633	5.054	44.687
Cluster 2	Maximum quality	26	7.488	8.117	15.605
	Optimal quality	16	7.927	4.083	12.009
Cluster 3	Maximum quality	40	7.268	8.671	15.940
	Optimal quality	16	7.927	4.083	12.009

Table D-2: Analysis of the results obtained for the reliability analyses in the rural feeder

Table D-2 identifies the maximum level of quality that can be achieved with each one of the technology clusters and the optimal level of quality. As mentioned in chapter 7, it can be seen that with only breakers and fuses, it is advisable to implement these devices at all possible locations. Thus, the optimal reliability level coincides with the maximum feasible. On the other hand, the penetration of fault detectors and reclosers allows attaining better levels of quality, although the new optimal level of quality (configuration 16) is not the best possible but the one where a tradeoff between consumers and DSO costs is balanced. Finally, the installation of telecontrol allows reaching higher reliability levels. However, this improvement is not enough to counterbalance the high cost of these technologies.

D.2 Urban feeder

All the results obtained for the urban feeder are presented in Table D-3. The reliability indices and the corresponding costs for the 75 feeder configurations analysed in section 7.4.1.2 are contained therein. The 13 non-dominated solutions of this case study are shadowed in grey.

	Configuration number	SAIFI	SAIDI	Consumers cost [€]	DSO costs [€]	Total social costs
Technology cluster 1	1	0.1125	2.67	47,115	1,911	49,026
	2	0.1125	2.32	40,863	2,139	43,001
	3	0.1125	1.96	34,611	2,367	36,977
	4	0.1125	1.79	31,649	2,595	34,244
	5	0.1125	1.62	28,688	2,823	31,511
	6	0.1	2.20	38,754	2,638	41,392
	7	0.0875	1.72	30,393	3,365	33,758
	8	0.08125	1.48	26,212	4,092	30,304
	9	0.075	1.25	22,032	4,819	26,851
	10	0.1	1.84	32,502	2,866	35,368
	11	0.1	1.66	29,376	3,094	32,470
	12	0.1	1.49	26,414	3,322	29,736
	13	0.0875	1.54	27,267	3,593	30,860
	14	0.0875	1.37	24,141	3,821	27,962
	15	0.08125	1.31	23,086	4,320	27,406
Technology cluster 2	16	0.1125	2.47	43,605	2,103	45,708
	17	0.1125	2.27	40,095	2,295	42,390
	18	0.1125	2.17	38,340	2,488	40,828
	19	0.1125	2.07	36,585	2,680	39,265
	20	0.1125	2.12	37,353	2,331	39,684
	21	0.1125	1.56	27,591	2,752	30,342
	22	0.1125	1.29	22,874	3,172	26,046
	23	0.1125	1.02	18,158	3,593	21,750
	24	0.0875	1.62	28,638	3,557	32,195
	25	0.0875	1.52	26,883	3,750	30,632
	26	0.0875	1.44	25,512	3,785	29,297
	27	0.0875	1.17	20,631	4,206	24,836
	28	0.10875	2.58	45,545	3,550	49,094
	29	0.105	2.49	43,974	5,189	49,163
	30	0.10125	2.40	42,404	6,828	49,231
	31	0.0975	2.32	40,833	8,467	49,300
	32	0.09375	2.23	39,263	10,106	49,368
	33	0.09	2.14	37,692	11,745	49,437
	34	0.10875	2.24	39,605	3,778	43,383
	35	0.105	1.82	32,095	5,645	37,740
	36	0.105	2.17	38,347	5,417	43,764
	37	0.0975	1.67	29,579	8,923	38,502
	38	0.0975	2.14	37,707	4,277	41,984
	39	0.0825	1.60	28,299	6,643	34,942
	40	0.10875	2.40	42,269	3,742	46,010
	41	0.105	2.12	37,422	5,573	42,995
	42	0.105	1.44	25,543	6,030	31,572
	43	0.105	1.14	20,245	6,486	26,731
	44	0.105	1.48	26,155	6,101	32,256
	45	0.1125	1.22	21,668	3,208	24,875
Technology cluster 3	46	0.1125	1.60	28,276	3,692	31,968
	47	0.1125	1.58	27,865	4,560	32,425
	48	0.1125	1.61	28,441	3,692	32,132
	49	0.1125	1.59	28,194	4,560	32,754
	50	0.1125	1.60	28,276	3,820	32,096
	51	0.1125	1.58	27,865	4,816	32,681
	52	0.1125	1.56	27,536	5,429	32,964
	53	0.1125	1.54	27,207	6,297	33,504
	54	0.1125	1.51	26,795	7,294	34,089
	55	0.1125	1.49	26,384	8,290	34,674
	56	0.1125	1.48	26,137	9,159	35,296
	57	0.1125	1.46	25,890	10,027	35,918
	58	0.0875	1.32	23,318	7,808	31,126
	59	0.0875	1.29	22,824	9,545	32,369
	60	0.075	1.19	21,045	10,799	31,843
	61	0.075	1.16	20,551	12,536	33,087
	62	0.1125	0.98	17,335	5,330	22,664
	63	0.1125	0.98	17,335	5,586	22,921
	64	0.1125	0.93	16,512	7,323	23,835
	65	0.0875	1.13	19,973	6,199	26,172
	66	0.0875	1.16	20,466	6,199	26,665
	67	0.0875	1.11	19,643	7,936	27,580
	68	0.1125	1.18	20,845	4,945	25,790
	69	0.1125	1.14	20,187	6,682	26,869
	70	0.1125	1.15	20,351	6,682	27,033
	71	0.105	1.10	19,570	8,223	27,793
	72	0.105	1.06	18,863	9,960	28,823
	73	0.0825	1.55	27,377	8,636	36,014
	74	0.0825	1.22	21,619	10,829	32,448
	75	0.0825	1.26	22,244	8,836	31,080

Table D-3: Detailed result for the reliability analyses in the rural feeder

In order to simplify the analyses of results, Table D-4 shows the maximum feasible level of quality in the different technology clusters and the optimal level of quality. Similarly to what happened in the rural feeder for technology cluster 1, it can be seen that the maximum level of quality coincides with the optimal level of quality for the first two technology clusters. Nonetheless, note that the best feeder performance is not obtained for the highest investment made by the DSO. This highlights the need for a careful reliability improvement planning. Lastly, it can be seen that telecontrolled devices allow achieving better quality levels, although once again the high investment costs make them unprofitable (with the consumer cost function considered).

		Configuration number	Consumer cost	DSO cost	Total social cost
Cluster 1	Maximum quality	9	22.032	4.819	26.851
	Optimal quality	9	22.032	4.819	26.851
Cluster 2	Maximum quality	23	18.158	3.593	21.750
	Optimal quality	23	18.158	3.593	21.750
Cluster 3	Maximum quality	64	16.512	7.323	23.835
	Optimal quality	23	18.158	3.593	21.750

Table D-4: Analysis of the results obtained for the reliability analyses in the urban feeder