SEVENTH FRAMEWORK PROGRAMME

THEME [ENERGY.2012.7.1.1] Integration of Variable Distributed Resources in Distribution Networks

Sustainable

(Deliverable 7.2)

Regulation for smart distribution grids with active DER integration

Lead Beneficiary:

COMILLAS

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1. Introduction

This report aims at providing recommendations for adapting current regulatory frameworks so as to encourage DSOs to deploy smart distribution grid solutions and achieve an efficient integration of DER. In order to attain this goal, the deliverable builds on and complements other pieces of work carried out within the SuSTAINABLE project, particularly within WP7 and WP8. Regulation may act as an enabler or a barrier to the realization of the deployment roadmaps defined in Deliverable 8.3 as well as the allocation of the costs and benefits identified and quantified in Deliverable 7.1 (selected use cases) and Deliverable 7.3 (VPP). Likewise, as discussed in deliverable 8.2, regulatory conditions in each country can significantly impact the scaling-up and replication of smart grid solutions such as the one tested and evaluated within SuSTAINABLE.

The report starts with a general discussion on the relevance of regulation and its potential impact on the deployment of smart grid solutions, focusing mostly on the role of DSOs and their interactions with DER for the provision of network services. Since the smart grid solutions considered within the project are quite diverse and regulation may be very broad, the specific regulatory topics relevant to the different functionalities and use cases have been identified. This will also allow highlighting the specific smart grid solutions that are affected by the regulatory recommendations provided.

In order to provide more specific recommendations and illustrate the many different alternative approaches to the regulation of DSOs, a set of European countries has been selected for the discussions. In line with previous works within the project, these include Portugal and Greece, as those countries where demonstration activities have been carried out, as well as the UK and Germany as partner countries.

Lastly, the core of this report consists in an identification of barriers and bottlenecks for the deployment of the previous smart grid solutions and the issuing of regulatory recommendations aiming to overcome these.

The remainder of the report is organized as follows. After this introduction, section 2 introduces the impact of regulation for the diffusion of smart distribution grids and describes the different regulatory aspects that ought to be considered in the analysis. Leveraging on the previous list of topics, section 3 maps the different regulatory topics to the SuSTAINABLE functionalities and use cases that will allow identifying the solutions affected by each regulatory recommendation. In section 4, the existing regulatory framework in the selected partner countries will be described and compared. Section 5 provides the main lessons learnt from the regulatory analysis carried out which consist of an identification of regulatory barriers for the deployment of the smart grid solutions studied and the provision of a number of recommendations to adapt current regulation. Finally, section 6 presents some concluding remarks.

1.1. Acronyms

AMI	Advanced Metering Infrastructure
BRP	Balancing Responsible Party
CAPEX	Capital Expenditures

CBA	Cost-Benefit Analysis
CEER	Council of European Energy Regulators
CHP	Combined Heat and Power
CI	Customer Interruptions (per 100 customers)
CML	Customer Minutes Lost
DEA	Data Envelopment Analysis
DER	Distributed Energy Resources
DG	Distributed Generation
DNO	Distribution Network Operator
DSM	Demand Side Management
DSO	Distribution System Operator
EMC	Electro-Magnetic Compatibility
ENS	Energy Not Supplied
ESCO	Energy Service Company
FACTS	Flexible AC Transmission Systems
FIP	Feed-In Premium
FIT	Feed-In Tariff
ICT	Information and Communication Technologies
IQI	Information Quality Incentive
IRM	Innovation Roll-out Mechanism
KPI	Key Performance Indicator
LCNF	Low Carbon Network Funds
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MV	Medium Voltage
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NRA	National Regulatory Authority
OLTC	On-Load Tap Changer
OPEX	Operational Expenditures
PQ	Power Quality
PV	Photovoltaics
QoS	Quality of Service
RAB	Regulatory Asset Base

RES	Renewable Energy Sources
RIIO	Revenue = Incentives + Innovation + Outputs
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SF	SuSTAINABLE Functionality
SFA	Stochastic Frontier Analysis
TIEPI	Tiempo de Interrupción Equivalente sobre la Potencia Instalada
TOTEX	Total Expenditures
ToU	Time of Use
TSO	transmission System Operator
TVPP	Technical VPP
UC	Use Case
UoS	Use-of-System
UPS	Uninterruptible Power Supply
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
WP	Work Package

2. Regulation and its impact on smart grid deployment

This report is motivated by the essential role regulation needs to play so as to foster the deployment of smart distribution grid solutions. The reason for this is twofold. On the one hand, power distribution is deemed to be a natural monopoly. Consequently, the remuneration and performance of DSOs are subject to some form of regulatory supervision. This implies that regulation will greatly influence the expenditure decisions made by these companies, both in terms of their amount and the type of expenditures incurred (e.g. CAPEX vs. OPEX or copper-and-iron vs. ICT-based solutions). On the other hand, distribution network users conventionally comprised exclusively passive consumers with very little, if any, interaction with the DSO. However, smart distribution grids require a more active contribution from distribution network users so as to reap the benefits of enhanced flexibility.

DSO regulation in Europe has generally evolved, at least partially, from a traditional cost-of-service regulation towards a so-called incentive-based regulation. This regulatory approach consists in setting ex-ante the prices or revenues, namely price cap and revenue cap regulation respectively, a DSO is entitled to recoup from the network tariffs for a given number of years; typically from 3 to 5 years. By doing this, network companies are encouraged to reduce costs, supposedly through efficiency gains, thus benefitting end-consumers in the form of lower electricity rates. In order to prevent DSOs from reducing costs at the expense of quality of service or jeopardizing the grid performance, ad-hoc incentive mechanisms have been widely introduced, mainly in relation to continuity of supply (CEER 2012) or energy losses (ERGEG 2009). Allowed revenues or prices have been oftentimes defined on the basis of benchmarking techniques through which the DSO performance is checked against their peers (similar DSOs) or against a theoretical benchmark constructed through bottom-up modelling.

Nowadays, it is widely believed that conventional incentive regulation schemes, particularly when appropriately implemented, have performed well in terms of cost reduction and continuity of supply improvement. However, they are also considered to provide DSOs with scarce incentives to adopt the smart grid paradigm by themselves (OFGEM 2010; Cossent 2013; CEER 2014; Eurelectric 2014). The main reason is that revenue or price caps are very good at encouraging short-term cost reductions, but fail to promote the long-term efficiency gains of smart distribution grids. Furthermore, existing regulatory approaches, for example, regarding benchmarking techniques or the definition of mandated continuity of supply levels rely on a stable and predictable behaviour of technologies and distribution network users. Notwithstanding, neither of these premises is bound to remain unchanged, as discussed on the ensuing.

On the one hand, smart grid technologies present significantly different features as compared to conventional network investments, e.g. in terms of useful lives and cost structure. So far, the deployment of smart grid technologies has been largely driven by ad-hoc innovation incentives and grants promoting demonstration and pilot projects. This is clearly shown in the comprehensive overview of R&D and demonstration projects in the area of smart grids across Europe is provided in (JRC 2014). However, the large-scale deployment of smart grid solutions over the long-term, intrinsic to the concepts of upscaling and replication or in the SuSTAINABLE roadmaps, may not rely on this type of mechanisms alone, but on adapted regulatory frameworks that promote innovation and long-term efficiency. Such regulation should reflect the new technology uncertainties faced by DSOs and the cost structure of smart grid solutions. In addition to the overall allowed revenue regulation for DSOs, the existence and design of complementary incentive mechanisms (QoS, losses) are relevant aspects for the deployment of the project's functionalities.

On the other hand, the behaviour of network users is becoming more uncertain due to the growing penetration of DG-RES and demand response. Conventionally, distribution network users mostly corresponded to end consumers that behaved rather predictably and inflexibly. Furthermore, their interactions with DSOs were generally limited to the grid connection/disconnection and, depending on the country, meter reading. However, the types and behaviour of distribution network users is deeply changing since end consumers are becoming more and more responsive to price signals, and growing levels of DG are being connected to the distribution grid.

The implications of such evolution in twofold. Firstly, DSOs find is much harder to foresee network investment needs due to varying demand patterns and the intermittency and location uncertainties of DG-RES. Thus, network planning, and the corresponding regulation, become more challenging tasks. Secondly, DSOs may try to rely on these DER so as to provide network services and potentially avoid or defer network investments. However, the regulatory mechanisms to enable DSOs to contract services from DER are not widely implemented yet.

Finally, in addition to the economic regulation of DSOs and the provision of network services by DER, this report will address several enabling technologies and solutions for the SuSTAINABLE functionalities that may be hampered by the lack of clear regulatory guidelines. These include DER aggregation, energy storage ownership rules, or the deployment and operation of smart metering infrastructure.

3. Mapping regulation to SuSTAINABLE functionalities and use cases

The functionalities and use cases analyzed within the project are quite diverse with respect to their goals, technologies involved and stakeholders affected. Consequently, not all of them will be equally affected by the different regulatory topics discussed in the previous section. Thus, in order to present more focused discussions about the impact of regulation of the future deployment of these smart grid solutions, they were mapped against a list of relevant regulatory topics. Moreover, this allows identifying what regulatory barriers and recommendations are relevant for each of the smart grid solutions evaluated. Note that these comprise not only the nine functionalities previously defined, but also an additional use case that has been considered in the CBA presented in Deliverable 7.1. The results of such analysis are summarized in Table 1, which can be found at the end of this section.

It can be observed that some regulatory issues can be considered as cross-cutting and affect all the functionalities. Among these, one may find the ad-hoc incentives for innovation, mainly related to financial risk mitigation to promote demonstration activities, as well as general revenue regulation approach, i.e. how DSO allowed costs are determined and regulated. The former would allow DSOs to test new solutions for the challenges they are facing or expect to face in the near future, whereas the latter would determine the future replication and deployment beyond pilot projects.

Whether a joint or separate **treatment of CAPEX and OPEX** is made in DSO regulation is a relevant issue for most functionalities, particularly those which aim to improve network reliability or to increase the network hosting capacity for DG (SF1-5, SF7, SF9 and UC1). Both types of problems have been conventionally tackled by means of enhancing network redundancy and reinforcement, i.e. CAPEX-intensive solutions. However, advanced solutions aim to achieve both goals more efficiently by reducing or deferring the amount of investment needs through solutions based on a more active grid operation, thus substituting part of the distribution CAPEX by OPEX[1]. Power quality issues have been excluded from this group as these functionalities do not really respond to the need to balance a CAPEX-OPEX trade-off but to new needs and problems derived from the connection of growing levels of DG and the increase in PQ requirements from end consumers.

Additionally, the incentives seen by DSOs to integrate DER more efficiently, and DG in particular, greatly depend on how and to what extent the incremental investments driven by these network users are recouped by DSOs. This brings about the need to review whether allowed revenue determination considers **DER-driven incremental costs** as well as the type of **connection charges** new DG units have to pay for. Hence, these topics are especially important in the case of those functionalities which allow DSOs to defer or avoid DG-driven investments. These comprise coordinated voltage control, TVPP as a support for network operators and flexibility based reinforcement planning (SF4, SF5 and SF7).

As mentioned above, DSO revenue regulation is usually reinforced with **output-based incentives** so as to prevent DSOs from neglecting important performance indicators, besides network expenditures, when implementing their cost-reduction efforts. These schemes most commonly

[1] Note that despite the fact that smart grid solutions imply investing in new types of assets, they should reduce the overall volume of CAPEX. Otherwise, conventional network reinforcement would be the most efficient alternative and these smart solutions should not be implemented under those circumstances.

address **continuity of supply** and distribution **energy losses**. The former would mainly affect the functionalities testing innovative approaches towards networks monitoring, protection and automation (SF3, SF9 and UC1); all of which directly improve network reliability or serve as enabling technologies for such purposes. On the other hand, the incentives to reduce energy losses would be relevant for use cases where the reduction of network losses is one of the main KPIs considered (SF 4, SF5 and SF8).

Furthermore, the aforementioned incentive schemes to improve continuity of supply and reduce energy losses may be complemented with **additional output-based incentives** for DSOs. Regulators are increasingly paying attention to a wider set of output indicators such as customer satisfaction, environmental impact, voltage quality or DG hosting capacity. In fact, several countries already monitor some of these output indicators and, in some cases, regulatory mechanisms have been established (CEER 2012; OFGEM 2013b; CEER 2014). The implementation of additional incentive schemes for DSOs can be an important driver for several of the functionalities, especially those aiming to increase the network hosting capacity for DG (SF4, SF5 and SF7) or to improve PQ levels (SF6 and SF8).

Until now, the focus has been placed exclusively on the economic regulation of DSOs. However, several functionalities require an active contribution of distribution network users. For instance, the Sustainable voltage control concept, in addition to DSO-operated devices such as OLTC and capacitor banks, include the participation of demand response, DG units and energy storage devices. Likewise, the main goal of the TVPP is to provide remunerated services both to different power sector stakeholders, particularly to the DSO. Furthermore, deliverable 4.2 proposed a market mechanisms so that DG units could provide harmonic compensation services to DSOs at the LV grid. All the aforementioned correspond to different types of services which can help DSOs rely on DER flexibilities so as to defer or avoid network investments. Therefore, the existence and design of regulatory mechanisms enabling the **provision of network services by DER** is a key issue for the aforementioned functionalities (SF4, SF5, SF7 and SF8).

It is important to note that the SuSTAINABLE demonstrators are focused on the integration of DER on the distribution networks. Nevertheless, the progressive decentralization of the power sector is bound to blur the conventionally tight borders between transmission and distribution networks. The most notable case is that of agents connected to the distribution grid participating in upstream energy or ancillary services markets. Such participation strengthens the need for accurately forecasting DER power injections and withdrawals as well as their aggregation to access such services (SF1, SF2 and SF5). The VPP is a business model enabling this participation, where the DSO would act as a facilitator for such transactions. Hence, regulation ought to define the **DSO-TSO interaction** in terms of responsibilities, data exchanges, etc. (ISGAN 2014; CEER 2015a).

Coming back to the issue of DER providing services to DSOs, there are several enabling solutions and technologies that may support the development of viable business models. Firstly, **DER aggregation**, already mentioned above as a solution to enable DER to access upstream markets, may be necessary to enable or facilitate DSOs to rely on DER flexibilities, which is precisely the goal of the TVPP concept considered in the project (SF5 and SF7).

Another technology which can be deeply affected by existing regulatory frameworks is energy storage, which within the SuSTAINABLE is considered to contribute to voltage control, the TVPP services and the distribution network flexibility-based planning. Energy storage could be owned by the DSO itself, thus being able to decide upon its location and operation. However, since storage assets may be used for other purposes beyond distribution network support, e.g. price arbitrage or balancing services provision, DSOs may be prevented from owning such assets on the grounds of the unbundling provisions set in EU Directive 2009/72/EC (European Communities 2009). Therefore, the functionalities relying on energy storage are dependent on the **ownership model for storage** defined by regulation (SF4, SF5 and SF7).

Lastly, **smart metering** is a key enabling technology for smart grid solutions involving some form of demand response and load flexibility, as it is potentially the case of voltage control and VPP functionalities. Moreover, network monitoring and state estimation at LV level is significantly enhanced thanks to the deployment of smart metering. Finally, the data recorded by smart meters is an essential input to RES production and load forecasting functionalities, enabling a higher degree of locational granularity in the forecasts. Therefore, regulatory dispositions regarding smart metering and AMI deployment functionalities and data access by DSOs can significantly limit the effectiveness, as well as their upscaling and replication potential, of the SuSTAINABLE functionalities previously enumerated (SF1-5 and SF7).

Table 1 Mapping of regulatory topics and SuSTAINABLE functionalities and use cases

Regulatory Topic/Functionality		SF1 RES forecasting	SF2 Load forecasting	SF3 Monitoring/ state estimation	SF4 Coordinated voltage control	SF5 TVPP as a support for DSO/TSO	SF6 Provision of differentiated QoS	SF7 Flexibility-based reinforcement planning	SF8 Power quality planning	SF9 Advanced protection planning	UC1 MV automation for reliability improvement
Revenue regulation	General regulatory approach	X	X	X	X	X	X	X	X	X	X
	CAPEX-OPEX treatment	X	X	X	X	X		X		X	X
	DER-driven costs				X	X		X			
Output-based incentives	Continuity of supply			X						X	X
	Energy losses				X	X			X		
	Others				X	X	X	X	X		
DSO incentives for innovation	Existence of incentives	X	X	X	X	X	X	X	X	X	X
	Design of incentives	X	X	X	X	X	X	X	X	X	X
Network charges for DER	Connection charges for DG				X	X		X			
	Use of system charges for DG				X	X		X			
DER provision of services	Voltage control				X	X		X	X		
	Congestion management					X		X			
	DSO-TSO interaction	X	X			X					
Business models for DER	DER Aggregation and VPPs					X		X			
	Storage ownership				X	X		X			
Smart meters	Functionalities	X	X	X	X	X		X			
	Ownership/data access	X	X	X	X	X		X			

4. Regulation in partner countries

In order to characterize different regulatory approaches across Europe, and in line with the other project deliverables, four partner countries have been used as case studies: Portugal, Greece, UK and Germany. Thus, existing regulatory barriers and bottlenecks will be later identified and discussed over these concrete examples. The main source of information corresponds to the regulatory questionnaire presented in Deliverable 8.2. Additional information and examples may be drawn from the scientific literature and public reports when deemed necessary to illustrate alternative regulatory approaches for specific topics. The resulting characterization of current regulation in the partner countries is summarized in Table 2 at the end of this section, and discussed in further detail throughout it.

4.1. DSO economic regulation

This section presents a cross comparison of DSO regulation in the four partner countries analyzed. This topic comprises not only the overall revenue regulation and its many complexities (section 4.1.1), but also the associated incentives that may be set by regulators in relation to continuity of supply, energy losses or innovation (section 4.1.2).

4.1.1 DSO revenue regulation

Section 2 discussed how DSO regulation in Europe has been progressively evolving from a more traditional cost of service regulation to a more incentive-based regulation. Moreover, it was mentioned that several regulators are already arguing for the need to go beyond conventional incentive-based regulation so as to promote innovation and achieve an efficient integration of DER. Performing a comparison among the four partner countries analyzed, it can be seen that a distinct regulatory approach may be found in each one of them. In fact, these four cases could be considered representative of the different alternatives that may be found across Europe. On the ensuing, the general approach to regulated DSOs is described for each partner country, ordered from the most cost-based scheme to the most incentive-based one:

- On one end of the spectrum, Greece applies a cost of service regulation. Thus, operation and maintenance costs as well as depreciation and investment costs are declared annually by the DSO. On the basis of this information, the regulator sets the allowed rate of return on investments and determines the DSO allowed revenues for the next year.
- In Portugal (mainland) a hybrid regulatory approach is followed. Cost reduction targets are set on OPEX whilst a cost of service approach is retained for CAPEX. Hence, the path of allowed OPEX is set every three years, being the efficiency requirements determined through a DEA benchmarking[2]. On the contrary, CAPEX are updated annually according to actual investments.

[2] Benchmarking technique relying on an optimization problem that determines the efficiency gap of each DSO as compared to a theoretical benchmark constructed from the data corresponding to actual DSOs. Since there is a single DSO in mainland Portugal, 14 provinces in the country are considered independently.

- DSO regulation in Germany[3] is, among the partner countries, the one closest to the most conventional incentive regulation scheme. DSOs are regulated under a revenue cap scheme with five-year periods. At each price control review, the regulator defines TOTEX allowances using different DEA and SFA benchmarking models to set future efficiency requirements. Investment needs are determined at the beginning of the regulatory period for the so-called base years. Only particular investments in high voltage may be specifically added on top of these revenue allowances.
- Lastly, the UK has recently carried out a substantial review of the regulation of energy networks which has resulted in a new form of regulation referred to as RIIO (Revenue equals Incentives plus Innovation plus Outputs). The main goal was to shift from an input-based regulation encouraging short-term cost reductions to an output-based approach that promote DSO innovation so as to achieve long-term efficient outcomes.

  One of the first implications of the RIIO review was an extension of regulatory periods from 5 to 8 years. In this case, despite the fact that a building blocks approach is followed to the assessment and determination of allowed costs (with ad-hoc benchmarking studies for different cost categories), a cap on TOTEX is set (assuming a pre-defined ratio of CAPEX/OPEX to update the RAB). Moreover, revenue allowances are determined by additionally considering detailed business plans elaborated by DSOs so that future investment needs an alternative solutions can be considered, instead of benchmarking costs exclusively on the basis of past information. Lastly, flexibility mechanisms have been introduced so as to mitigate the effect of uncertainties derived from the changing environment faced by DSOs as well as the effect of longer regulatory periods.

4.1.2 Regulatory incentives

Additional incentive schemes are frequently implemented on top of DSO revenue regulation. This has been conventionally done in order to prevent quality of service or other performance indicators from deteriorating as a result of cost reduction efforts. More specifically, continuity of supply, i.e. the number and duration of supply interruptions, and distribution network losses are the most commonly addressed aspects. The usual approach consists in defining a bonus-malus-scheme, i.e. setting a reference value for a measurable indicator to be controlled for and setting penalties for DSOs that perform worse than that reference or, on the contrary, additional revenues for DSOs performing better than the reference. Nonetheless, incentive schemes may present important differences concerning their design, indices measured, etc. This is clearly shown in the subsequent descriptions:

- In Greece, incentive schemes only target loss reductions so far. In this case, a symmetrical bonus-malus mechanism is in place. Network losses are valued considering both the day-ahead market price and the cost for deviation settlement (adjusted for price effects). Concerning continuity of supply, several indicators, including SAIDI and SAIFI, are monitored, although no related financial incentives or penalties are applied. Notwithstanding, such scheme is expected to be implemented in the future.

[3] Discussions in this report will refer to the regulation of the DSOs with more than 30000 connections which are subject to regulatory oversight by the Federal Regulator. Smaller DSOs are subject to a simplified regulation and are overseen by state authorities.

- In Portugal, there are incentive-penalty schemes both for continuity of supply and network losses. In the former case, despite the fact that several other reliability indices are monitored by the regulator (SAIDI, SAIFI, MAIFI), the incentive scheme is applied on an estimation of the ENS obtained from the value of TIEPI. As shown in Figure 1, the design includes a deadband around the reference value and cap-floor limits. In the case of energy losses, the incentive mechanism also includes a deadband around the reference value (set at 7.8% in the latest price review). Energy losses are valued at one third of the average spot price.

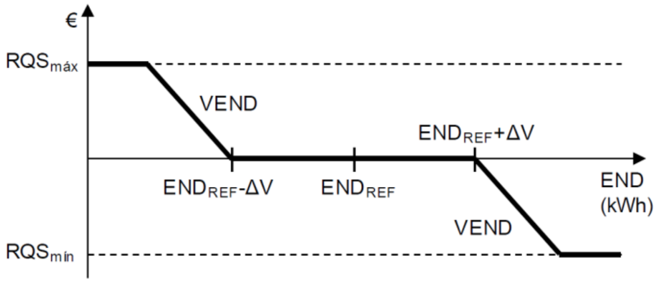

Figure 1 Continuity of supply incentives for DSOs in Portugal (ERSE 2013)

- In Germany, DSOs regulatory incentives also cover both continuity of supply and losses. In this case, both SAIDI and SAIFI are considered by the regulator. Moreover, cap-floor limits are set to mitigate the financial exposure of DSOs and reference values are set on the basis of cross-comparisons among DSOs. Regarding losses, the volume of allowed losses is capped per voltage level during the whole regulatory period. The value of losses is calculated yearly by using the EEX futures market (18-6 months in advance) with a fixed mixture of base and peak.
- The case of the UK is quite similar to the previous ones concerning continuity of supply, i.e. a bonus-malus mechanisms is applied. The indices monitored are the CI and CML (variations of SAIDI and SAIFI), a cap-floor system is used and reference values are set on the basis of historical values. Notwithstanding, the previous bonus-malus scheme to promote the reduction of energy losses was removed due to concerns about insufficient and inconsistent measuring data. Alternatively, in addition to reporting obligations, DSOs are required to explicitly include strategies for loss reduction into their forward-looking business plans. Moreover, the regulator may provide DSOs with a discretionary reward on top of their allowed revenues when it may be considered that the DSO has, for example, managed to identify more cost effective and innovative ways of reducing network losses.

However, QoS or energy losses are not the only types of incentive schemes for DSOs that may be found. Additional mechanisms may intend to encourage certain behaviour of expenditures from DSOs. Conventionally, these mechanisms were mostly related to what may be referred to as commercial quality indicators, such as timely connection of new network users or time taken to respond to a complaint. Nonetheless, a much more extensive use of output indicators is deemed necessary to promote a deeper change in the current distribution network planning and operation practices (CEER 2014).

The UK is presumably the partner country showing the most advanced regulation in this regard. Moreover, it is a good example to show that bonus-malus schemes are not the only alternative to use output indicators for regulatory purposes. This type of mechanism is still applied on issues such as customer satisfaction, connection processes or complaint handling; i.e. the most conventional indicators. The main barrier with alternative indicators when setting bonus-malus schemes is that it may not be ensured that their measurement may be carried out in an objective and transparent way or that these are fully controllable by DSOs. Notwithstanding, a much wider range of indicators may be simply monitored for the sake of transparency or to develop DSO scorecards to determine the degree of regulatory scrutiny, as done in the UK with personnel health and safety, asset loading and condition indices, or the carbon footprint. Furthermore, the UK regulator may provide DSOs with discretionary rewards in case their performance is deemed appropriate in areas such as environmental impact, stakeholder engagement or vulnerable consumers support (OFGEM 2013b).

4.1.3 DSO innovation incentives

The transition towards smarter distribution grids requires carrying out demonstration and pilot projects both to test and develop innovative technologies and to enable DSOs to gain experience and trust in such solutions. In Europe, DSOs, as well as many other types of stakeholders, may access funds for such projects from public budgets, either at European level (e.g. Horizon 2020) or at national (either federal or regional) level. This is in fact the case in all the partner countries discussed in this report. Nonetheless, additional specific financing and incentives to innovate may be provided within the regulatory framework itself. This means that the cost of innovation may be recouped, at least partially, through the electricity tariffs. Moreover, these incentive mechanisms are usually designed by and under the supervision of energy regulators.

In Germany and Greece, there is no specific mechanism to promote demonstration projects embedded within the DSO regulatory framework, albeit these projects may be approved by the Greek regulator and included in the allowed cost of service. On the contrary, ad-hoc incentives for innovation do exist in Portugal and the UK:

- The Portuguese regulation states that at least 2.5% of distribution investments submitted to the regulator for approval have to correspond to innovation projects. In case these are approved by the regulator, the DSO would receive a mark-up on the rate of return for a period of 6 years. This type of incentive is enabled when CAPEX are regulated under a cost of service regulation.
- Owing to its regulatory design, the UK has implemented a significantly different approach to encourage DSO innovation. Firstly, the mandatory eight-year investment plans submitted by DSOs should specifically consider smart grid solutions when possible, including a CBA-based assessment of the proposed investments. At the same time, the proposed investments should leverage on the results from demonstration projects funded through the incentive mechanisms in place during previous regulatory periods, e.g. the LCNF described in (OFGEM 2009).

  Lastly, specific incentives for demonstration activities have not been completely phased out. Innovation stimulus comprise a yearly competition for funding large projects covering up to 90% of the costs (the network innovation competition or NIC), use-it-or-lose-it allowance of 0.5-1% of annual base revenues for small-scale projects (network innovation allowance or NIA), and roll-out incentive for future large-scale deployment of innovative solutions pre-approved by the regulator (innovation roll-out mechanism or IRM). The overall funds and duration of the support is limited and subject to detailed justifications and information disclosure obligations.

4.2. Economic signals for DG

Several of the functionalities tested in this project aim to increase the network hosting capacity for DG and/or involve the provision of network services by DG. In these cases, the incentives seen by DSOs and DG operators may be strongly influenced by the economic signals received by these generators and the payments they make to DSOs as distribution network users. Therefore this section reviews the current situation in the partner countries concerning this aspect of regulation.

4.2.1 Distribution network charges for DG

The distribution network charges are the payments made by network users so as to pay DSOs for the cost of the grid. Conventionally, these charges were paid exclusively by end consumers given that no other type of user was connected at distribution level. However, the growing penetration of new types of DER is altering this paradigm. Distribution network charges comprise both the so-called use-of-system (UoS) charges, periodic charges paid to recoup the allowed revenues determined by the regulator, and connection charges, one-off payments to compensate DSOs for the cost of grid connection. In both cases, significantly different approaches may be observed among the partner countries.

Regarding **UoS charges**, the UK is the only country where DG units pay network charges similarly to consumers. These are paid as a term expressed in £/kW and specific calculation methodologies are applied depending on the voltage level of connection and size of the generator. In Greece, DG units also have to pay UoS charges, although these only have to cover the O&M costs of those network assets that used exclusively or almost exclusively used by generators. These charges are paid on the basis of a contracted capacity. In the remaining two countries, Germany and Portugal, DG pays no UoS charges. Notwithstanding, in Germany, some units connected to the lower voltage levels receive the so-called “avoided network fees”, for the benefits they supposedly create by producing electricity close to where it is consumed. In most cases, the avoided costs are assumed to be already included in the FIT and no extra payment is made.

Concerning **connection charges**, it is relevant to identify the approach followed for their calculation. The so-called deep connection charges would include all the costs of grid connection, including any reinforcement necessary in the upstream part of the grid. On the contrary, under shallow connection charges, DG units would only pay for the direct costs of connecting to the nearest network bus. Intermediate approaches, known as shallowish connection charges, may be found. These may consist in charging DG units only a predefined share of the total costs of connection, or in making them pay only for the costs corresponding to the same voltage level at which they are being connected, leaving out any upstream reinforcement costs. In the case of shallow and shallowish approaches, the share of connection costs that are not recouped through the connection charges, are socialized among rate payers and recovered through the distribution UoS charges.

Having a look at the situation in the partner countries, a range of alternatives can be seen. On the one hand, both the UK and Germany make DG promoters pay shallowish connection charges. Nonetheless, these are calculated following different approaches. In the UK, connection charges are computed following publicly available rules that are published by DSOs in their webpages after the approval of the regulator. A particular feature of UK’s regulation is that part of the connection assets, known as contestable work, may be developed by a third party under competition[4]. In Germany, the shallowish connection charges are calculated through the summation of several lump sums determined on the basis of predefined rules (capacity to be connected, distance to the grid, etc.). If the applicant carried out personally some of the work (e.g. ditch digging), the connection costs have to be reduced accordingly. Furthermore, DG units below 30 kW located where there is an existing grid connection point (e.g. inside a consumer's premises) are connected free of charge.

On the contrary, both Portugal and Greece apply deep connection charges for new DG units calculated by the DSO. In the case of Portugal, the computation rules are published and pre-approved by the regulator.

4.2.2 Remuneration schemes for DG production

The most relevant economic signal received by DG operators is not the network tariffs themselves but the remuneration they obtain for their actual energy production. In the European context, DG units mostly correspond to RES generators and CHP units. Owing to their lower environmental impact, the installation of these technologies has been strongly promoted through specific **support payments** as an alternative or a complement to the market price. A comprehensive review of existing support schemes across Europe may be found in (CEER 2015b).

Within the partner countries, the FIT seems to be the most common approach, being present in all of them. In fact, this is the main promotion mechanisms in three of the countries evaluated, namely Portugal, Greece and Germany. In the UK, only generators with a rated capacity below 5 MW are eligible to receive the FIT. Larger generators would directly participate in the wholesale market, and receive renewable obligations, also known as tradeable green certificates, which they may also sell to energy suppliers so that these may comply with their corresponding quotas.

However, **self-consumption schemes**, largely present in other part of the world as in the US, are being increasingly implemented in Europe as an alternative mechanism to sustain the growth of DG-RES whilst mitigating the upwards pressure on the cost of RES support. Additionally, self-consumption increases consumer awareness and promotes DG to be located closer to the consumption, where it is potentially more beneficial. Nevertheless, flawed designs of self-consumption policies may lead to inefficient decisions from end-users and even have jeopardize the power sector viability, particularly in the presence of non-cost-reflective tariffs and net-metering policies. A review of self-consumption schemes and best practice guidelines are provided in (European Commission 2015). In fact, all the partner countries considered in this report have already implemented some form of self-consumption:

- Greece: net-metering is allowed for consumers with PV installations at their premises as long as these do not surpass 50% of the consumer's contracted capacity and the generation installed capacity does not exceed 20kW.
- Portugal: prosumers may self-consume the energy they produce locally within an hourly period, i.e. they only pay for the net consumption within an hour. Surplus production is remunerated at 90% of the spot price.

[4] https://www.ofgem.gov.uk/electricity/distribution-networks/connections-and-competition/competition-connections

- Germany: due to the evolution of regulation and its regional fragmentation, several different self-consumption and net-metering schemes can be found across the country. Additionally, there is a large number of PV owners who receive a reduced FIT for the energy that is self-consumed. After a legislative change, these schemes are not available to new promoters nowadays. Thus, only instantaneous self-consumption is possible for new PV units. Notwithstanding, the high volumetric component of the electricity tariff in Germany makes self-consumption quite attractive.
- UK: self-consumption is possible for wind and solar installations below 50kW. DG owners receive not only a generation tariff for the amount of energy that is self-consumed but also an export premium for up to 50% of the energy fed into the grid.

4.3. DER service provision and business models

The previous subsections have revised the partner countries situation concerning DSO economic regulation on the one hand, and the economic signals seen by DG unit on the other. This section now shifts the focus toward the interactions between DSOs and DER so as to support distribution grid operation as well as the business models that enable such interactions.

4.3.1 Mechanisms for the provision of network services by DER

The SuSTAINABLE project has defined several functionalities which require network users to provide services to DSOs such as voltage control, investment deferral or power quality management. This implies a change in paradigm since distribution network users have conventionally behaved passively with respect to network conditions. This was possible because distribution networks were designed according to a fit & forget approach, ensuring that no problems could arise during grid operation. Nonetheless, such a change requires regulatory mechanisms that enable the active participation of DER. Due to the regulated nature of DSOs, regulatory oversight is necessary to ensure efficient and transparent results. Several alternatives can be found for the provision of network services by DER: mandatory requirements, incentive schemes, local markets or bilateral agreements between DER operators and DSOs.

A shown on the ensuing, the degree of implementation of such mechanisms is rather limited across partner countries, presumably being this situation rather similar in other European countries. The few existing mechanisms mostly correspond to mandatory requirements or ad-hoc bilateral agreements with DSOs. Moreover, these have normally been implemented so as to minimize the effect of DG connection or to be used under emergency conditions rather than an additional operational tool.

- In Greece, DG unit have to provide voltage control and active power modulation as a mandatory requirement. Concerning voltage control, the DSO may choose between power factor control (between 0.95 lagging to 0.95 leading), power factor control or direct voltage control respecting the injection and absorption capabilities of DG. With respect to active power management, the DSO may curtail DG production under emergency conditions, in case of failure or maintenance or when the connection technical assessment shows this is the most efficient alternative technically and economically. No demand response schemes accessible to DSOs exist.
- In Portugal, neither DG units nor loads interact with DSOs for the provision of network support.

- In Germany, PV and wind units, which account for the vast majority of DG capacity, have to comply with different power factor requirements depending on the installed capacity, voltage level and technology. These requirements imply complying with a power factor of at least 0.9 in all cases. No compensation is provided for this service. Moreover, DG units may be curtailed under emergency conditions by DSOs. When this happens, the DSO has to compensate the DG operator for the energy not injected at the level of the corresponding FIT. In order to provide such service, new PV plants larger than 30 kWp are mandated to install a communication interface allowing the DSO to reduce their power injection. PV units below 30 kWp may choose either to permanently reduce active power injections to 70 % of the installed capacity or to install the same equipment as larger plants. At the moment, there are discussions about advanced forms of DG curtailment enabling DSOs to truly rely on this option as an operational resource.

  Furthermore, demand response mechanisms are available to DSOs in Germany. These correspond to legacy schemes, implemented prior to the power sector liberalization, mainly addressing domestic heating appliances. Installations controlled through this scheme usually have their own meter for a separate billing process. Nonetheless, the load control mechanism is based on fixed time schedules given by the DSOs rather than in response to actual network conditions. In addition to this legacy scheme, DSOs are obliged by Law to offer a reduced UoS charges to those LV network users who allow for the controllability of their loads. Under this arrangement, DSOs would be entitled to switch off the customer's load when needed. However, this provision needs to be further developed through suitable regulatory mechanisms, thus not being ready for large scale deployment yet.

- In the UK, DG units must operate at a power factor within the range 0.95 lagging to 0.95 leading unless otherwise agreed with the DSO. No additional form of service provision by DG units exists. In the case of loads, non-firm network access is offered by DNOs to large consumers. Under this scheme, the network charges paid by the consumers involved are reduced in exchange for allowing the DSO to interrupt them under certain conditions. See, for instance, the DSM agreements described in (SP Energy Networks 2014).

4.3.2 DER-related business models: DER aggregation, ESCOs and storage

Given the relatively small size of many distribution network users, the intermediation of aggregators jointly managing the flexibilities of a portfolio of users may be necessary to enable the interactions between DSOs and DER and reduce transaction costs. In fact, a TVPP would be essentially an aggregator. Nonetheless, the degree of development of such activities seems to be rather limited across Europe, especially concerning the provision of services at distribution level (SEDC 2015c). In fact, the focus so far has been mainly placed on providing demand resources access to wholesale markets, ancillary services markets or capacity mechanisms. Moreover, since such a task may be carried out by existing suppliers (which are as well BRPs) or by independent aggregators, attention is being paid to the effect of demand variations over the system-wide and BRP-specific imbalances (SEDC 2015b; SEDC 2015a).

Another stakeholder group which may interact with end consumers and DG operators, especially in the case of prosumers, is the one corresponding to ESCOs. This business model is more widespread than that of aggregation, albeit it is not generally focused on the participation of demand in electricity markets or services. Despite the fact that their business models are not usually specifically oriented towards the power sector, they may play a role on the deployment of DG or in the provision of differentiated QoS and PQ services. Therefore, these agents may affect several project functionalities, in particular SF6 and SF8.

Lastly, storage is a new type of resource that could be increasingly connected to the distribution grid provided that adequate cost reductions are achieved and clear regulation passed. In fact, this type of innovative asset has been considered in several of the project functionalities. Nevertheless, regulation still needs to define the potential role of DSOs in the deployment and operation of storage devices, more specifically clearly define whether this is a fully competitive activity or, on the contrary, DSOs may play a more active role under certain conditions (CEER 2015a). Across Europe, the installation of distributed storage seems to be limited to demonstration projects in which DSOs own and operate the storage assets (mostly batteries). However, the regulatory guidelines for the long-term operation of such assets are still missing. Italy is presumably the only country where the regulator has made specific proposals (AEEGSI 2015).

The review of the existing regulation and market conditions in the four partner countries considered are consistent with the previous discussion of the European situation. This means that ESCOs are already an operative business models providing a wide range of energy services, whereas the development of DER aggregation is quite limited and storage oftentimes not even considered by regulation. Further details are presented on the ensuing:

- In Greece, DER aggregation is non-existent and no relevant regulation governing storage ownership is in place. On the other hand, ESCOs do operate in the country, mainly providing energy efficiency services for buildings, industry and transportation. These services include thermal insulation, lighting, heating/cooling, CHP or microgeneration.
- The situation in Portugal regarding aggregation and distributed storage is similar to the Greek one and these are, therefore, completely undeveloped activities. Notwithstanding, ESCOs do provide end consumers with a wide range of services. These correspond, on the one hand, to rather conventional energy management services such as energy efficiency improvements, energy audits, home energy management systems or ToU tariffs. Nevertheless, ESCOs additional may already provide QoS services to end consumers so as to improve the PQ levels they receive through actions and devices such as capacitor banks, power factor control, UPS installation or electronic speed control.
- In Germany, load aggregators do exist and operate in the energy market albeit such business model is not widely developed yet. Despite the fact that demand side bidding is in place both for wholesale and balancing markets, the entry barriers as well the need to clarify balancing responsibilities of independent aggregators are hampering such development. As in the previous two countries, ESCOs are active in Germany. This sector presents a rather large and well-functioning market with services comprising energy efficiency measures in buildings, heating services contracting, market trading of RES production or energy management for industries. Lastly, DSO ownership of energy storage is specifically forbidden by Law. This position has been clearly supported by the regulator. Nonetheless, regulation does not forbid any other system user from owning storage. In fact, there is an existing program which provides low-interest loans and repayment subsidies for new solar PV installations below 30 kW which incorporate a battery storage system, subject to strict technical requirements.
- The UK presents one of the most mature markets for commercial aggregators in Europe. Such agents already participate extensively in the provision of balancing services. Furthermore, load aggregators may access the recently created capacity market, albeit market design barriers are

reported in (SEDC 2015c). ESCOs have also been active for quite some time in the UK. These companies mainly offer services related to energy efficiency, the installation of heat pumps of micro-CHP units, management of energy expenditures or home automation (Boait 2009). Lastly, no regulation has been passed regarding storage ownership models.

4.3.3 Smart metering

Directive 2009/72/EC mandates a roll-out of smart-meters by 2020 that ought to reach at least 80% of end consumers (European Communities 2009). The main goal of such guideline is to unlock the demand response potential and stimulate the retail market competition, particularly at the residential commercial and level. In the case of the SuSTAINABLE functionalities, several of them rely on the presence of smart meters as discussed in section 3. However, such roll-out was subject to a positive CBA carried out by each Member State. According to the survey in (European Commission 2014a; European Commission 2014b), only 16 Member States have plans to proceed to a large-scale roll-out before 2020.

In addition to the deployment of AMI, the model adopted concerning metering deployment and data management can be a relevant issue affecting the implementation and effectiveness of the functionalities involved. See (CEER 2015a) for a brief description of the different alternatives. As shown below, the situation in the four partner countries analyzed in this report concerning both smart meter deployment and data management shows several different situations representative of the European context.

- In Greece, metering is considered as a regulated activity. The DSO is the entity responsible for meter deployment, maintenance and data management. The CBA carried out, which included up to six different scenarios, yielded a positive result. Hence, a roll-out schedule has been approved to replace at least 80% of the old metering devices by the year 2020, including several intermediate targets as shown in Figure 2.

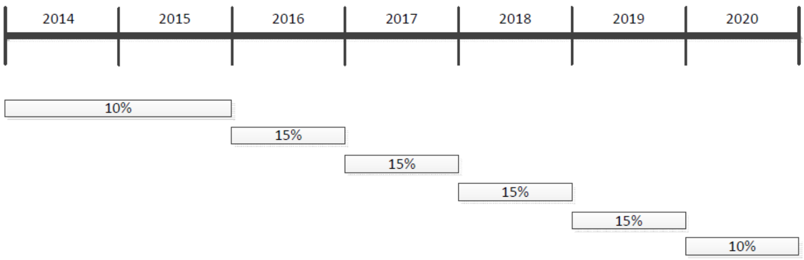

Figure 2 Smart meter roll-out plan in Greece (European Commission 2014b)

- In Portugal, the organizational model for the metering activity is similar to the Greek case. This is a fully regulated activity which is carried out exclusively by the DSO, both with respect to meter ownership and maintenance, and metering data management. However, the results of the CBA exercised in Portugal yielded inconclusive results. Therefore, despite the fact that pilot projects are ongoing, a policy decision about the large-scale roll-out of smart metering is still pending.
- In Germany, end consumers are entitled to freely choose their own metering operator, i.e. the metering market has been liberalized. Thus, smart meters are to be deployed by the corresponding metering operator. Nevertheless, DSOs are the default metering operator and,

therefore, they perform this task unless the consumer has explicitly opted for a different operator. Consequently, DSOs may still carry out most of the smart meter deployment. On the other hand, metering data management is the responsibility of gateway administrators, which may or may not coincide with the metering operator. Note that this is a highly complex task that requires undergoing through a costly certification process, which may be a barrier for small DSOs. Hence, it is expected that many smaller DSOs will not become gateway administrators in spite of being metering operators.

The CBA for Germany was carried out by a private consulting firm, and the results supported just a partial roll out of smart meters. At the moment, the German legislation mandates the installation of smart metering only in connection points where: the annual consumption exceeds 6000 kWh, a new RES generator over 7 kW is installed, newly built or deeply renovated consumers' premises, and in all other connections when this is technically possible and economically feasible. The large-scale roll-out in the remaining situations in under discussion between the relevant stakeholders and thus, the final policy decisions is still to be made.

- The UK presents yet another organization model for the metering activity. As in the German case, meter deployment and ownership is considered as a competitive activity. However, in this case, it is electricity suppliers which hold these responsibilities. Regarding the role of metering data management and making it accessible to third parties, this would be a task of an independent entity or central data hub. This role is played by the so-called Data and Communications Company. The CBA on smart metering resulted in a positive business case. Accordingly, the policy authorities have made a decision to mandate the large-scale roll-out of AMI in all residential and small non-residential consumers. Thus, most households are expected to have a new meter installed by 2020.

Table 2 Summary of regulatory conditions in partner countries

Regulatory Topic/Partner Country		Portugal	Greece	UK	Germany
DSO revenue regulation		Cost of service for CAPEX Price cap on OPEX, 3-year periods. DEA benchmarking	Cost of service regulation. Building blocks	Revenue cap, TOTEX with pre-defined share of OPEX-CAPEX, 8-year periods, menu of profit-sharing contracts (IQI). Ex-ante assessment of business plans through several benchmarking models (esp. econometric models)	Revenue cap on TOTEX, five-year periods, DEA-SFA benchmarking across DSOs, using base years for new investments (except special investments)
Continuity of supply	Incentive design	Yes. Bonus-malus	No. Expected in the future	Yes. Bonus-malus	Yes. Bonus-malus
	Indices	Monitored only: SAIDI, SAIFI, MAIFI Incentive: TIEPI-ENS	Monitored only: SAIDI, SAIFI	Incentive: CI, CML	Incentives: SAIDI, SAIFI
	Other	Two-year lag; cap and floor scheme	-	Two-year lag, Cap and floor scheme, reference values based on historical values	Cap and floor scheme, reference values based on cross-DSO comparisons
Energy losses		Yes. Bonus-malus. Deadband. Value of losses 1/3 average pool price	Yes. Bonus-malus. Value of losses related to wholesale prices	No incentive. Business plans must justify efforts in loss reduction. Discretionary reward by regulator	Yes. Losses are capped per voltage level. Prices are calculated yearly by using EEX futures market (18-6 months in advance) with a fixed mixture of base and peak.
Ad-hoc Innovation incentives (beyond government or European funding)		Extra RoR for 6 years on innovative investments (determined by regulator). At least 2.5% of investments submitted for approval must be innovative	Subject to regulatory approval. No specific regulation	Investment plans should proof a positive CBA for innovative solutions, leveraging on results from previous funding. Innovation stimulus: competition for project funding among DNOs, use-it-or-lose-it allowance, roll-out incentive	No specific regulation
Other regulatory incentives/standards		Grid connection: e.g. Max. time to connect DG	Grid connection: e.g. Max. time to attend connection requests	Incentive: customer satisfaction and complaints, grid connection Monitoring: health and load indices, carbon footprint Discretionary reward: environmental impact, stakeholder engagement, vulnerable consumers support	Grid connection
Network charges for DG	UoS charges	No	Yes. O&M costs of assets used (almost) exclusively by DG. Allocated by contracted power	Yes, based on published methodologies	No. Payment of avoided network costs in some cases
	Connection charges	Deep, rule-based	Deep, calculated by the DSO	Shallowish, rule-based	Shallowish, rule-based Shallow for units below 30kW
Network services by DER	DG	None	Power factor limits (close to unity), power factor control or voltage regulation. Active power curtailment (emergency conditions). Mandatory requirement	Power factor limits (close to unity), power factor control (if agreed with the DNO). Mandatory requirements	Power factor limits (per technology and voltage level) DSO DG curtailment under emergency communication Mandatory requirements (curtailment is compensated at FIT)
	Loads	Flexibility contracts with TSO	Only large consumers with TSO	Non-firm network access for large consumers in exchange for a reduction in network charges	Controllable loads by DSOs (temperature dependent loads). Regulated system from pre-liberalization. Non-firm network access pending legal development
Business models	DER aggregation	No	No	Yes, for balancing services	Yes, load aggregation but not widely developed
	ESCOs	Yes. Quality of supply (capacitors, power factor control, UPS), energy efficiency, energy audit, time of use tariffs, energy management	Yes. Energy efficiency, RES, CHP	Yes. Energy efficiency, CHP, other energy services	Yes. Energy efficiency, energy management and aggregation
	DSO ownership of storage	Not regulated	Not regulated	Not regulated	Forbidden
DG remuneration	Support schemes	FIT	FIT	FIT (below 5MW), renewable obligations (above 5MW)	FITs and FIPs
	Self-consumption	Self-consumption (excess energy paid at 90% of wholesale price)	Net-metering (PV max. 20 kWp or 50% of the contracted power)	Self-consumption for PV and wind below 50kW, excess production paid at ad-hoc generation tariff	Existing units: several forms of self-consumption and net-metering, even in combination with FITs New units: only self-consumption
Smart metering	CBA	Yes. Inconclusive	Yes. Positive	Yes. Positive	Yes. Positive in some cases
	Type of activity	Regulated	Regulated	Competitive	Competitive
	Roll-out plan	Decision pending	Yes. At least 80% by 2020. Intermediate target: 40% by mid 2017	Yes. 100% households by 2020	Decision pending
	Meter ownership	DSO	DSO	Supplier	Metering point operator (could be the DSO)
	Data management	DSO	DSO	Central hub	Metering gateway administrator (could be the DSO)

5. Barrier identification and regulatory recommendations

This section constitutes the core of this report. It builds on the analyses carried out in previous work within the project which has evaluated the economic implications of the project's functionalities and use cases (CBA, VPP economic interactions) as well as their potential for upscaling and replication, both at local level and at macro-scale level. This review will be made following the same regulatory topics discussed in previous sections. For each topic, the barriers and bottlenecks for the implementation of the different functionalities and use cases are firstly identified. Subsequently, regulatory recommendations to encourage the deployment of smart grid solutions and achieve an efficient DER integration are proposed. When relevant, these are prioritized per group of countries or regulatory model, identified through the review presented in section 4 and the SuSTAINABLE roadmaps.

5.1. DSO economic regulation

The economic regulation of DSOs is one of the most relevant topics that ought to be revisited so as to encourage an effective and efficient deployment of advanced distribution solutions, given the monopolistic nature of this activity. Hereinafter, barriers caused by the current revenue regulation and design of regulatory incentives will be discussed and recommendations to mitigate or overcome them provided.

5.1.1 DSO revenue regulation

Barriers:

One of the main goals of smart grid solutions is to allow integrating high shares of DG-RES more efficiently as compared to conventional grid reinforcements or the deployment of dedicated feeders for generation units (see footnote 1). Likewise, network automation allows DSOs to use ICT-based solutions as an alternative to network redundancy for the improvement of reliability levels. In all these cases, smart grid solutions would thus reduce overall investments, usually in exchange for increased OPEX. However, some regulatory frameworks can create barriers for these solutions as they would tend to encourage DSOs to increase their RABs instead of reducing overall expenditures[5]. This would be the case under cost of service regulation, as in Greece, or under incentive-based regulation where CAPEX are excluded, at least partially, from efficiency requirements, as in Portugal.

However, the implementation of ex-ante revenue allowances including CAPEX can create the so-called CAPEX time-shift problems (Eurelectric 2011; Eurelectric 2014). This implies that DSOs would not be remunerated for the investments carried out during a regulatory period at least until the beginning of the next period, i.e. after several years have elapsed. This problem is bound to arise under a purely ex-ante regulation, especially when conventional backward-looking benchmarking

[5] This statement would hold true on condition that the allowed WACC remains above the actual cost of capital of DSOs. If this condition is not met, DSOs would tend cut network investments. However, this would not be a result of properly designed regulation encouraging efficiency gains but on a flawed regulatory decision that may lead to underinvestment and, over the long-term, cause network problems.

approaches are applied. Such methods oftentimes rely exclusively on historical information and cross-comparisons across DSOs instead of considering the future investment needs of each DSO, which may, for instance, face different DG penetration levels as a result of factors outside the control of the DSO.

Such an approach was sensible in an environment characterized by stable technologies and predictable demand. Nevertheless, these conditions do not hold anymore in many cases precisely due to the growing penetration of DER and smart grid technologies. Among the partner countries, Germany is a clear example where this problem may arise as DEA and SFA benchmarking models are applied to determine allowed investments for the so-called base years. The UK is an example where some actions have been taken to mitigate this problem. Therein, conventional regression benchmarking models have been fed both with past information and forecasted data (OFGEM 2013c). Additionally, DSOs were required to submit forward-looking investment plans which had to include the possibilities offered by smart grids and DG, through the application of a common engineering model (OFGEM 2013a).

Noteworthy, even the previous barriers were overcome, uncertainties are bound to increase driven by the more volatile behaviour of network users, e.g. DG promoters may respond to changes in support or self-consumption policies, or that fact that smart grid technologies may cause rapid changes in the conditions assumed in order to compute the ex-ante allowances. Therefore, purely ex-ante revenue setting may increase the risks faced by DSOs and promote conservative strategies. Moreover, unforeseen deviations of actual costs from revenue allowances may increase for reasons outside then control of DSOs, either creating financial stress on DSOs or providing them with windfall profits. This risk would be again mainly present in the case of Germany. On the other hand, in Portugal and Greece, the pass-through of investment costs would remove such risks, albeit at the expense of weaker incentives for efficiency. Lastly, the NRA in the UK has introduced a flexible remuneration mechanism that adapts revenue allowances within the regulatory period. This is known as the IQI mechanisms, as explained in (OFGEM 2013b).

The last barrier identified with respect to the regulation of DSO revenues is slightly more subtle than the previous ones. This refers to the inherent incentives for DSOs to focus on short-term cost reductions instead of long-term efficiency gains (e.g. investment deferral) deriving from the input orientation and the frequent occurrence of distribution price reviews. Among the partner countries, the RIIO reform in the UK is presumably the country which has already adapted its regulation to overcome this particular barrier, whereas Germany would be the country where such adaptations could be most immediately implemented.

Recommendations:

- Implement incentives for DSOs to reduce their expenditures. These efficiency incentives should be neutral to CAPEX and OPEX reductions so as to allow DSOs to exploit the potential trade-offs between CAPEX and OPEX, e.g. investment deferral. This can be achieved through an incentive-based regulation following a TOTEX approach where RAB additions are made independent of actual DSO cost allocation.
- Adopt forward-looking cost assessment methodologies and mandate DSOs to submit detailed investment plans to regulators. Benchmarking approaches may increasingly use bottom-up models capable of reflecting the specific conditions faced by each DSO as well as the impact of smart grid solutions. Thus, ex-ante revenue allowances should be set on the basis of the

expected operating conditions faced by DSOs and avoid the CAPEX time shift problem caused by backward-looking cost assessments.

- Introduce flexibility mechanisms in remuneration formulas so as to mitigate uncertainties, especially if the length of regulatory periods is extended (see next bullet point). The main existing schemes comprise profit-sharing mechanisms or even trigger-based reopeners for the most extreme deviations.
- In addition to the previous recommendations, extending the length of regulatory periods would allow DSOs to reduce the resources devoted to time-consuming price reviews and adopt a long term perspective. Furthermore, progressively shifting the focus of regulatory supervision from investment adequacy (inputs) to the outputs delivered by DSOs, beyond continuity of supply and energy losses, is advisable. This last topic will be addressed in further detail in the next subsection.

5.1.2 Regulatory incentives

Following the current regulatory practices, as presented in section 4.1.2, this section will mainly focus on two types of regulatory incentives for DSOs: network reliability and energy losses. As discussed on the ensuing, the existence of these incentive mechanisms is a key driver, or at least a complementary one, for the implementation of several smart grid solutions and functionalities tested within the SuSTAINABLE project. Hence, several implementation and design features may act as barriers for such functionalities and use cases.

5.1.2.1 Continuity of supply

Barriers:

On the one hand, the existence of incentives promoting improvements in continuity of supply is a pre-requisite or a main driver for the implementation of smart grid solutions based on network monitoring (SF3), protection (SF9) and automation (UC1). European regulators have traditionally placed a strong importance on continuity of supply. Hence, bonus-malus schemes are widespread across EU countries, including the partner countries evaluated in this report. It is only in the case of Greece that such incentive schemes have not been implemented yet. Notwithstanding, this situation is expected to be modified in the near future since the sector is currently in the midst of a profound regulatory reform.

However, the existence of these incentives is not enough by itself to promote such functionalities since an appropriate design and implementation, which can significantly differ on a per country basis, are also essential. For instance, countries like UK or Germany set incentives related both to the frequency and the duration of supply interruptions. On the contrary, in Portugal, despite the fact that both SAIDI and SAIFI are monitored, the economic incentives exclusively depend on an index measuring the duration of interruptions. This can dilute the incentives seen by DSOs to implement network monitoring and automation for fault detection and reconfiguration, since these solutions may not only achieve a reduction in the duration of interruptions, but also the measured number of interruptions provided that all or part of the network users that have suffered an interruption are re-supplied within the time threshold beyond which an event is considered as a long interruption. This threshold is typically set at 3 min across EU countries, including partner countries (CEER 2012).

Additionally, it is relevant whether planned interruptions are excluded from the indicators considered for the calculation of the incentives and penalties, as well as what criteria are to be met for an interruptions to be registered as such. Most European countries, including the partner countries, record planned interruptions separately. However, the conditions to be complied with by DSOs can change significantly across countries, e.g. the minimum notice time for consumers (between 15 days and 24h), type of announcement (written, mass media, other) or administrative permissions necessary. Given that the aforementioned functionalities/use cases would mainly operate under unplanned conditions requiring a fast DSO response, those countries where the previous criteria are more rigorous, it is more likely that a certain share of interruptions known in advance by the DSO are included in the unplanned reliability indicators. As a consequence, network monitoring and automation would reduce the value of reliability indices proportionally less, thus mitigating the benefit for DSOs of their implementation.

Lastly, there are two parameters which are key to the design of any bonus-malus scheme: the reference level (sometimes referred to as target level) and the unit incentive. The former determines the threshold beyond which DSO revenues increase if actual levels of continuity of supply exceed it and vice versa, whereas the latter can be interpreted as the marginal value of reliability for network users. From a theoretical perspective, the power of the incentive exclusively depends on the unit incentive (Cossent 2013). Therefore, an optimal incentive scheme (when linear) should be symmetrical so as not to distort the incentives. Notwithstanding, the design of these schemes oftentimes include dead-bands or caps/floors which introduce discontinuities. See, for instance, the Portuguese design shown in Figure 1 (cap & floor systems are also in place in Germany or the UK).

Hence, whenever a DSOs presents reliability levels that are within the dead-band or above/below the cap/floor the incentives to implement network automation would be weakened. In principle, this could be prevented by updating the reference values as suitable. However, since reference values are usually defined based on past performance, as it is the case in the UK or Germany, this may result in a permanent stagnation of reliability levels.

Regarding the unit incentive, this parameter has been conventionally estimated by quantifying the cost of interruptions for consumers or a cost of energy not-supplied (CEER 2010). However, the suitability of the values actually used by regulators or their calculation methods to promote smart grid investments is hard to assess externally. This is due to the fact that the calculation methods are quite heterogeneous and oftentimes not published by regulators. This evaluation would require estimating both the marginal cost of improving reliability (including smart grid solutions) as well as the cost of interruptions for consumers in each country. However, this does not seem to be the case in practice. Given the new opportunities and costs offered by smart grid solutions to improve distribution reliability, regulatory practices should move away from simply using historical values towards more detailed assessment of the aforementioned cost curves.

Recommendations:

- Implement incentive-penalty schemes, either linear or non-linear, for DSOs to improve network reliability in those countries where this is not the case nowadays. Moreover, these mechanisms ought to comprise indicators measuring both the number and duration of interruptions since both aspects are relevant for end users.
- Symmetric incentives without dead-bands are advisable to prevent creating distortions in the incentives seen by DSOs. On the other hand, caps and floors may indeed be necessary to

mitigate DSO risk. However, these parameters should be reviewed and updated, consistently with reference values, so as to prevent a stagnation in reliability levels when further cost-efficient improvements are feasible.

- The determination of incentive rates should not be based exclusively on historical values. Hence, regulators should carry out more detailed assessment of the both the marginal cost of improving reliability (including smart grid solutions) as well as the cost of interruptions for consumers in their country.

5.1.2.2 Energy losses

Barriers:

On the other hand, the incentives to reduce energy losses can be a relevant driver for smart grid solutions related to a more efficient integration of DER through voltage control, TVPP or PQ enhancement (SF4, SF5 and SF8 respectively). The main objective goal of these functionalities is to increase network hosting capacity. Nevertheless, energy losses can be seen as an added benefit contributing to attaining an overall positive business case. Note that the impact of these smart grid solutions would refer exclusively to technical losses, i.e. those whose cause is to be found in physical phenomena occurring in network components. Nonetheless, network monitoring and LV supervision, albeit not considered within the context of the SuSTAINABLE project, could additionally be used to identify non-technical losses and define loss reduction strategies specifically targeting this problem.

Ad-hoc performance incentives seek to encourage DSOs to reduce energy losses because energy losses do not constitute a direct cost for them since, due to unbundling provisions, they do not buy or sell any electricity (ERGEG 2008; ERGEG 2009). Bonus-malus schemes for energy losses reduction are in place in Portugal and Greece. In Germany, DSOs also se incentives to reduce energy losses since the amount of losses passed-through to the tariffs are capped per voltage level (expressed as a percentage of the energy distributed). In the UK, the regulator has not implemented an explicit incentive-penalty mechanism. Notwithstanding, loss reduction is promoted through other means, including the fact that DSOs are mandated to explicitly address loss-reduction actions in their business plans and a discretionary reward for best practices by DSOs.

The incentives to reduce energy losses share several common design issues with those related to continuity of supply, as shown in the subsequent discussion. Firstly, in both cases, wide dead-bands and cap/floors systems may act as a barrier since DSOs would see little incentives from improvements in the corresponding output indicator. Given that distribution losses are greatly influenced by the location and behaviour of network users, DSOs controllability over energy losses is rather limited. This effect is bound to worsen as DG penetration increases. Therefore, retaining caps/floors may be advisable to mitigate this risk. On the contrary, setting reference values on the basis of historical data could benefit or jeopardize DSOs for issues outside their control since reference values, when calculated this way, do not capture the impact of DER on network losses.

In this case, defining the value of the unit incentive is comparatively more transparent and objective than in the case of continuity of supply since market prices can be considered as a good estimation of this parameter. Section 4.1.2 showed that this is in fact in line with regulatory practices in all partner countries which use as reference either the spot prices (as in Portugal, Greece and UK) or the prices in the futures markets (as in Germany). Setting the unit incentives in line with the actual value of losses provides DSOs with the right signal for their reduction. However, this does not ensure that additional barriers may not arise. For instance, in Portugal, energy losses are valued at a third of market prices, thus significantly diluting the power of the incentive mechanism.

Moreover, the incentive rate is oftentimes defined ex-post once the actual yearly average market prices are known, particularly when spot prices are considered. Setting this value in advance would provide higher certainty to DSOs when internalizing the cost of losses into their operation and investment decisions. This is the case, for instance, in Germany where the incentive rate is calculated by using prices in the futures market (known between 8-6 months in advance) with a fixed mixture of base and peak periods.

Lastly, linking the value of losses to wholesale prices makes DSO incentives to depend strongly on system conditions and the energy mix. In this regard, the progressive RES penetration in European markets is modifying price patterns, creating many hours with very low (or even negative prices) and some hours with peaking or scarcity prices (the trend, either upwards or downwards, in average prices may change on a country basis) (Pérez-Arriaga and Batlle 2012). This effect could be therefore passed-through to the incentives seen by DSOs depending on whether the time-dependence is embedded into the incentive schemes or not. In practical terms, this would imply that DSOs could be equally encouraged to reduce losses at all times, particularly during peak conditions in their distribution areas (which do not necessarily coincide with system peaks); or they could focus on reducing losses in periods with high energy prices.

Recommendations:

- Assess energy losses quantification methods and their potential for accuracy improvement by incorporating smart metering data. This would allow regulators to fine-tune existing incentive mechanisms (Portugal, Greece and Germany) as well as re-introducing incentive/penalty schemes in the UK, where these were removed due to the lack of reliable data.
- Symmetric incentives without dead-bands are advisable to prevent creating distortions in the incentives seen by DSOs. On the other hand, caps and floors may indeed be necessary to mitigate DSO risk given that the behaviour of network users, largely uncontrollable by DSOs, can significantly affect distribution losses. These parameters should be reviewed and updated as needed so as to prevent an inefficient stagnation in the level of losses.
- The reference losses, sometimes referred to as target losses, should incorporate the impact of DER on network losses so as to prevent windfall profits/losses for DSOs as a result. This would imply abandoning simple approaches based on historical data as well as considering the specific conditions faced by each DSO in this regard.
- Incentives for the reduction of losses should expose DSOs to the quantity risk, which they can partly control. However, price risks should be mitigated or totally avoided since the unit cost of losses is not a controllable parameter for the DSO.
- Incentive rates (value of losses) should be set ex-ante on the basis of forecasted prices or futures prices so as to provide DSOs with further certainty when determining their loss-reduction strategies. Additionally, this incentive rate should reflect the full value of losses since otherwise, DSOs would be encouraged to attain a suboptimal level of losses.

5.1.2.3 Other output-based incentives

Barriers:

Section 4.1.2 showed that regulators consider additional output-based incentives besides those related to continuity of supply and energy losses. Notwithstanding, these have been traditionally limited to different aspects of commercial quality based on minimum standards, most notably the time taken to attend a new grid connection request, as it is currently the case in all partner countries considered herein. However, (CEER 2011; CEER 2014) suggest that an enhanced use of output indicators by regulators could support the transition to an smart distribution grid in a more efficient manner. The indicators evaluated therein comprise, among others: network hosting capacity, energy not withdrawn from renewables and satisfaction of grid users.

Among partner countries, the UK is the only member state which shows relevant progress in this regard. After the implementation of RIIO regulation to regulate electricity DNOs, OFGEM monitors indicators about personnel health and safety, asset loading and condition indices, or the carbon footprint. Furthermore, DSOs may earn discretionary rewards for performing well with regard to environmental impact, stakeholder engagement or vulnerable consumers support. Lastly, more conventional incentive-penalty schemes have been defined on more conventional indices including customer satisfaction, connection processes or complaint handling (OFGEM 2013b).

The change of the regulatory focus from an input-oriented towards an output-oriented approach can thus represent a significant push for smarter distribution grids in general, and particularly for the SuSTAINABLE use cases and functionalities[6] dealing with QoS provision and PQ planning (SF6 and SF8) as well as those aiming to achieve a swifter and more efficient integration of DER, mostly DG (SF4, SF5 and SF7). This may result in a wider range of bonus-malus incentive mechanisms on output indicators besides continuity of supply and energy losses. However, this would only be advisable in case these variables are controllable by the DSO and they can measured in an objective and transparent way (CEER 2014).

Complying with the previous criteria is one of the main challenges when introducing new incentive schemes. Therefore, alternative approaches may be adopted to overcome this particular barrier whilst still encouraging DSOs to deploy innovative solutions. These may comprise indicator monitoring, build scorecards, discretionary rewards, assessments of DSO investment plans or in combination with menu regulation. Examples of most of these applications can be already found in the UK or the recent New York proposals (OFGEM 2013b; New York DPS 2015).

Recommendations:

- Bonus-malus schemes may be implemented for output indicators as long as these are controllable by the DSO, they are technology-neutral and they can be measured in an objective and transparent way. A progressive implementation is recommended so as to gain experience in measuring and comparing new indicators before full DSO exposure to incentives/penalties.
- In case the previous conditions are not fulfilled, regulators should explore the use of additional output indicators and alternative applications besides bonus-malus schemes such as monitoring, scorecards, discretionary rewards or assessment of DSO investment plans.

[6] The type of Smart grid solution most prominently promoted would naturally depend on the output indicators selected by regulators as well as the power of the incentive mechanisms implemented.

5.1.3 DSO innovation incentives

Barriers:

The previous adaptations of the DSO revenue regulation and their incentive mechanisms may not be enough to spur the deployment and experimentation with technologies that are still undeveloped, but promising nonetheless. Hence, input-based incentives for promoting innovation by DSOs may be needed to help bridge this gap. Across Europe there are innovation programmes accessible to DSOs both at European-wide and national level, as it is the case in all partner countries. However, the focus of this section is placed on those mechanisms designed by electricity regulators specifically targeting DSOs whose cost is at least partly defrayed through the tariffs. Since this particular regulatory issue is transversal to all smart grid technologies and solutions, it can be deemed to be relevant for all functionalities and use cases.

The design of these incentive mechanisms has to be consistent with the overall regulatory design. For example, the fact that distribution investments in Portugal are subject to a cost of service regulation enabled the regulator to promote smart grids by ensuring DSOs a temporary mark-up on their allowed WACC for those investments. However, this approach would not be possible in other countries where a TOTEX regulation is in place, as in Germany or the UK. The latter country has adopted an alternative approach where demonstration costs are excluded from the overall revenue regulation. Instead, DNOs may access specific funds for innovation under a competitive tendering scheme (NIC), use a discretionary expenditure allowance of up to 1% of their annual base revenues (NIA), or roll-out proven solutions under the innovation roll-out mechanism (IRM). In order to ensure that rate-payers money is well spent, information disclosure obligations on DSOs are advisable, potentially including CBA or scaling-up and replication analyses.

One of the most relevant potential problems with these mechanisms is that regulation should ensure promoting only technologies that require such support so that DSOs do not take the low-hanging fruit only. Likewise, regulators should avoid providing additional remuneration for investments that DSOs would make anyway under a suitable remuneration framework or those that are already being recouped through regular remuneration mechanisms (double payment). Furthermore, input incentives require extensive regulatory oversight to assess, approve and monitor demonstration activities. As a consequence, the regulatory burden could be unsustainable considering a large-scale deployment.

Hence, the input-oriented incentives should be gradually phased-out as technology matures and sufficient experience is gained. On a transitional basis, DSOs could be encouraged to progressively consider smart grid investments as a complement or alternative to conventional iron-and-copper assets, i.e. to go from demonstration to deployment. For instance, the UK regulator already requires DNOs to do so in their mandatory business plans, where they have to justify through CBA the proposed investments leveraging on the results from previous demonstration activities.

Recommendations:

- Innovation incentives are advisable to spur demonstration activities by DSOs and promote the development of new solutions for DSOs. These ought to include knowledge-sharing and information disclosure obligations for DSOs.

- The design of innovation incentives should be consistent with the overall DSO regulatory framework so as to avoid a double payment or paying for something that DSOs would have implemented anyway.
- These incentives may start out as input-oriented mechanisms, either in the form of additional capital remuneration, or as a complement to the overall allowed revenues. Notwithstanding, these should progressively evolve in such a way that explicit incentives are phased out in favour of implicit incentives embedded within the regular remuneration schemes.

5.2. Economic signals for DG

The incentives seen by both DG and DSOs to adopt solutions that entail modifying the conventional passive behaviour of DG greatly depend on the economic signals seen by DSOs and addressed in the previous section and the economic signals seen by DG operators. Consequently, regulators may need to review current approaches towards the definition of network charges for DG as well as the remuneration mechanisms for these generators. A particular emphasis will be placed on self-consumption schemes given the growing popularity of this policy alternative in European countries (European Commission 2015).

5.2.1 Distribution network charges

Barriers:

Connection charges, i.e. a one-off payment to cover the expenses incurred for grid connection, serve the purpose of sending siting and sizing signals to applicants. In principle, regulators face a trade-off between sending strong locational signals (deep charges) or mitigating the barriers for DG grid connection (shallow charges). However, in the end, deep connection charges oftentimes act a major barrier for an efficient integration of DG. Note that under deep connection charges, the full connection costs are defrayed by DG promoters. Consequently, DSOs see little incentive to seek less costly grid connections by avoiding or deferring network investments, especially when this has to be done at the expense of higher OPEX due to incentive-based regulation. Therefore, this can be an important barriers for functionalities aiming to reduce DER integration costs (SF4, SF5 and SF7).

Furthermore, deep charges present additional undesired side-effects such as a perceived lack of transparency from network users, particularly when these are calculated by the DSO without clear computation rules, and free-riding (first-comers use the available capacity at a low cost then costly reinforcements are paid by a few). These can be especially problematic for smaller units, for whom the connection costs may amount to a significant share of the total project costs. An additional argument in favour of shallow charging is that the location of DG units is usually driven by land and resource availability rather than network signals. Hence, deep connection charges may introduce important economic barriers for generation projects, without affecting DG location efficiently. What is more, Article 16 of EU Directive 2009/72/EC states that, where appropriate, Member States may require DSOs to bear, in full or in part, the grid connection and reinforcement costs.

Hence, countries applying deep connection charges for DG, such as Portugal and Greece, should consider migrating towards a shallow or shallowish charging approach, particularly for small DG units. In fact, Germany, which has shallowish charging in place, already applies less costly connection fees for generators below 30 kW. In any case, albeit particularly when deep or shallowish charges are levied, rule-based calculations provide higher transparency and simplicity to the computation process. This approach is followed in Portugal, UK and Germany. According to these rules the connection charges to be paid by DG units are obtained as the addition of several lump sums that depend on the installed capacity, distance to the main grid or voltage level at the point of connection.

Whilst connection charges mainly influence investment and locational decisions from DG promoters, UoS charges address operational decisions of DG units, i.e. power injections at each period of time. However, this effect can be expected to be relatively minor given that DG is largely based on non-controllable technologies whereas controllable production would mainly respond to energy prices (as discussed in section 5.2.2). Among partner countries, the UK is the only one where DG units pay actual network charges that may be comparable to those paid by the demand. In order to prevent altering efficient operational decisions, DG UoS charges are levied through a capacity term (£/kW) whose value depends on the voltage level and installed capacity.

Consequently, in the absence of UoS charges for DG, consumers would be the only network users contributing to recoup network costs. The potential future deployment of distributed storage may pose an added barrier in this regard, since it would be unclear whether these assets would be considered as consumers, thus paying UoS charges, or otherwise. In order to prevent this discrimination and create a level playing field for all network users, UoS charges should be made independent of the type of network user (i.e. technology neutral), contrary to what is common nowadays.

An additional problem of the conventional approach where only loads are charged for the use of the distribution grid is already seen, for instance, in the case of Greece. In this country, an exception has been included in the regulation so that DG units defray the costs of developing networks that are exclusively devoted to the connection of DG. Situations where DG is the main driver for distribution investments are bound to become more and more common in European countries where load growth is oftentimes stagnated (even a declining peak demand has been observed over the last few years in some member states) and more ambitious decarbonization goals are being pursued.

Recommendations:

- Deep connection charges should be abandoned in favour of shallowish or shallow calculation methods so as to prevent adverse consequences and remove barriers for the connection of DG, particularly in the case of smaller units.
- Connection charges should be calculated on the basis of transparent and objective rules so that DG promoters perceive transparency and lack of discrimination.
- UoS charges should be paid by all distribution network users and defined in a technology-neutral manner. Therefore, tariff structures should be the same regardless of the type of network user paying them, i.e. consumers, generators or even storage systems which may act as both depending on the time.
- Capacity-based UoS charges are recommended for DG promoters so as to prevent affecting negatively operational and pricing decisions. This tariff should be time-differentiated and could potentially be negative or positive reflecting the actual impact on the network at a specific bus/area and time period.

5.2.2 Remuneration schemes for DG production

Barriers:

Given that DG in Europe consists almost exclusively of RES-based generation or other technologies that present some form of environmental advantage, e.g. CHP or waste-to-energy, specific support schemes have been conventionally the main mechanisms driving the deployment of small-scale generation. More specifically, FITs are the most widespread mechanisms to remuneration the production of DG-RES across partner countries, being present in all of them at least for smaller generation units. Nonetheless, more market-oriented approaches can be found, as FIPs in Germany or renewable obligations in the UK (units above 5MW).

The reason why these mechanisms may act a barrier for different SuSTAINABLE functionalities is that their design may or may not enable DG units to respond to network needs and/or provide network services such as voltage control (SF4), be managed under a TVPP (SF5) or flexibility provision to defer network investments (SF7). The high remuneration faced by DG-RES at certain times can effectively hamper changing active power injection patterns according to network needs, even if specific regulatory mechanisms are implemented as it is discussed in section 5.3.1. This is particularly noticeable in the case of flat FITs and, to a lower extent, FIPs which essentially encourage the maximization of total electricity production over the year.

Despite the fact that the aforementioned support schemes are still the main RES promotion policy across Europe, self-consumption has been steadily gaining in relevance. In fact, all partner countries evaluated in this report have already adopted some form of self-consumption scheme. Among the benefits or self-consumption over traditional support payments the following may be mentioned: it promotes locating DG units closer to the demand, mitigates the upwards pressure on system costs driven by RES support, it additionally promotes demand response and distributed storage when appropriately implemented, it raises consumer awareness and participation (especially in sectors that have been traditionally passive such as the commercial and residential ones), and it presents low transaction and implementation costs.

However, inappropriately designed tariffs, i.e. those based mainly on a volumetric charge, may drive inefficient decisions from end users (e.g. over-dimensioning DG units) and even jeopardize fixed cost recovery. Note that such volumetric tariffs would intend to recoup fixed system costs (such as transmission and distribution networks, system operation or RES support costs) through an energy tariff component. This effect is especially noticeable under net-metering schemes, which are oftentimes characterized as using the distribution grid as a storage system. Thus, net-metering is implicitly valuing the excess production at the level of the retail tariff paid by the corresponding consumer. Eventually, this may create a vicious circle whereby regulators are forced to raise tariffs to achieve cost recovery, which at the same time strengthens the incentives to self-consume. Ultimately, this may result in the disconnection from the distribution network (grid defection). Moreover, such a flawed policy design, i.e. the combination of volumetric tariffs with net-metering, in spite of providing strong economic incentives to install DG, demand response and distributed storage are discouraged because the main grid is used as a storage to smooth-out the fluctuations in local production.

The partner countries considered in this report already show different means to mitigate the potential negative impact of self-consumption of system cost recovery: limiting the size of installations (Greece or UK), reducing the netting interval, etc. However, this still does not ensure a sustainable development of self-consumption. This would require abandoning net-metering policies and finding alternative approaches to remunerate excess production. This is actually the case already in Portugal, the UK or Germany (for newly installed generation). The alternatives that may be found include compensation excess energy at a specific FITs, using market prices as a reference or even do not remunerate excess production at all.

However, the most effective and efficient approach involves defining cost-reflective electricity tariffs showing a suitable time differentiation. The resulting tariff structure may involve introducing a much more relevant capacity and/or fixed component in many cases. This has been sometimes opposed because it is seen as a barrier for demand response and energy efficiency. Notwithstanding, this would be the most efficient approach provided that such tariff structure adequately reflects the underlying cost structure.

Last but not least, it is important to highlight that the deployment of smart metering technologies is a key enabler for such business model. In the absence of smart metering, bi-directional power flows could not be measured on an hourly basis, as required by the most advanced and efficient forms of self-consumption. Smart metering issues are discussed in section 5.3.3.

Recommendations:

- Flat remuneration schemes (e.g. FITs or high FIPs) can hamper the active participation of DG. Hence, regulators and policy-makers should ensure that support levels reflect the technological evolution. Eventually, support payments ought to be phased-out.
- Self-consumption should be promoted so as to encourage demand response, distributed storage and small-scale DG. Moreover, self-consumption can help raise consumer awareness and participation in sectors which have traditionally behaved rather passively.
- Net-metering should be abandoned in favour of instantaneous (e.g. hourly) self-consumption schemes where the excess production is valued according to the value of energy in the corresponding time period.
- Smart metering and a cost-reflective tariff design are essential for an efficient diffusion of self-consumption that both promotes growing levels of DG-RES and ensures the long-term financial viability of the power system. Whilst these conditions are fulfilled, several “safety net” mechanisms may be introduced such as size limitations, shortening netting periods, or implementing alternative schemes to remunerate excess production.

5.3. DER service provision and business models

The previous two sections placed the emphasis on DSOs and DG-DER respectively. Now the focus will be shifted towards the mechanisms and business models enabling the interactions between network operators and network users. The necessary regulatory means are virtually non-existent nowadays owing to the fact that distribution network have been conventionally passively operated and DER have been connected through a fit-and-forget paradigm. However, both network users and DSOs should progressively adapt their role either by engaging in the provision of network services, resorting to the intermediation of new agents if necessary, or deploy new infrastructure technologies (e.g. energy storage or smart metering).

5.3.1 Mechanisms for the provision of network services by DER

Barriers:

Distribution network users have traditionally been behaved passively with little interaction with the network operator; a situation which was made possible by conservative distribution network planning methods. A flexibility-based network development and a more active role of DER is definitely needed to ensure a more efficient evolution of the distribution grid and the power system as a whole. Nevertheless, the mechanisms enabling and promoting such an active role of DER are scarcely developed, as already shown in section 4.3.1. These mechanisms and guidelines comprise both those related to the provision by DER of services to the DSO itself, and the provision of services to upstream actors (mainly the TSO) and markets.

The services provided to DSOs are relevant for functionalities related to voltage control, flexibility-based planning, differentiated power quality or the TVPP (SF4, SF5, SF6 and SF7), whereas the issue of TSO-DSO interaction is relevant not only for the provision of services by DER at wholesale level (SF5) but also for the exchange of information such as forecasts for demand and generation (SF1 and SF2).

The former group of functionalities, i.e. those involving the provisions of services to the DSO, need to overcome barriers arising from the regulatory framework as well as from technical characteristics of the distribution networks and the nature of the services to be provided. This is the reason why this is nowadays mainly limited to mandatory power factor control requirements on DG units or curtailment possibilities in case of emergency, both for DG and large consumers. Furthermore, these provisions are oftentimes based on mandatory requirements or legacy schemes stemming from pre-liberalization times. Hence, the main challenge is how to adapt and extend these mechanisms so that they become an additional operational tool for DSOs and the service is provided and responsibilities allocated in a more efficient manner. Additionally, requirements have oftentimes been determined in a centralized manner without attending to the local network conditions. As a result, the burden of actually providing the service may not be distributed evenly across potential providers and even additional network constraints can be created[7].

The most straightforward approach is to implement the already mentioned mandatory requirements on different types of DER, e.g. conditions to be complied with before being granted grid access. Whilst this is a simple and effective approach, they may not be the most efficient approach when the service provision implies a significant added cost on the DER operator, e.g. DG active power curtailment or load interruption. The main causes of these inefficiencies are that potential providers which are not initially included in the requirements are not encouraged to adapt their systems, and that the costs of complying with the requirements as well as the capabilities may not be the same or equally costly for all providers[8]. This could happen for instance in the case of DG voltage control through a P-V droop controller for the LV network. In practice this service may

[7] For instance, time-dependent fixed power factor control for DG units may create voltage fluctuations when a relatively large number of neighbouring DG units change their set-point simultaneously.

[8] The first reason is somewhat similar to the rationale behind the evolution of some variable renewable technologies which were originally excluded from deviation penalties and which increasingly gained in forecast accuracy after this situation changed. Nowadays, intermittent generation is even providing balancing services in some countries. The second reason resembles the rationale behind cap and trade systems for emissions control being more economically efficient that simple standards.

imply a curtailment of RES production and, depending on their location, the same units would presumably be providing the service most of the time.

In these cases, incentive schemes could be used to compensate DER for their incremental costs in subject to compliance. Notwithstanding, the issue of efficient allocation and local network conditions would still be insufficiently addressed. Local markets for flexibility, as in (Trebolle et al. 2010; Poudineh and Jamasb 2014), can effectively overcome most of the previous difficulties. However, local markets for ancillary services such as voltage control or congestion management can be very hard to implement in practice, especially at the lower voltage levels, due to the limited number of providers of the service for a given area (Eurelectric 2016). Hence bilateral flexibility contracts or obligations may be a more suitable alternative. Note that these contracts can be even be allocated through tendering mechanisms[9]. In any case, regulatory supervision is necessary to ensure no discriminatory treatment and appropriate remuneration mechanisms are applied. Thus, these contracts ought to be standardized in terms of product definition, remuneration, technical conditions, etc.[10]

The previous discussion could be applicable to a wide range of flexibility services including voltage control, congestion management, or firm capacity for investment deferral. However, it may be harder to apply to other more technically complex services, in particular PQ differentiated service provision. Note that, as mentioned in deliverable 4.2, PQ mitigation measures may be adopted at different levels: equipment level, process level, plant level and network level. DSOs and distribution regulation would only be involved in relation to the last one of these levels, i.e. upstream of the users' meters. Otherwise, regulation may be enabling DSOs to provide potentially competitive services to specific consumers which could be alternatively provided by ESCOs or similar agents, as discussed in section 5.1.3.1.

Treating PQ as a service allows addressing the fact that different users present different levels of PQ requirements. However, when addressed from the distribution network side, e.g. through premium quality contracts, they are bound to lead to free-riding as acknowledged in D3.6. Therefore, the specific needs of some users may be more efficiently addressed from the customer side of the meter, thus outside the domain of the DSO. Notwithstanding, market mechanisms may indeed yield more efficient outcomes than mandatory EMC standards when trying to limit the emission of PQ disturbances by network users since compliance costs may be uneven across them. Thus, emission permits would be allocated through market-based approaches as suggested in (Driesen et al. 2002). Important challenges would still exist in terms of defining the product or commodity, defining the geographical area covered by the market (PQ problems have a local component), permit allocation rules, etc.

Coming back to the discussion at the beginning of this section, DER may not only provide services at distribution level but also at wholesale level, as pursued by the TVPP SuSTAINABLE functionality (SF5). In fact, this is bound to become more and more necessary as the generation capacity is increasingly decentralized. This would require DSOs to adopt new roles as market facilitators by validating that the offers submitted by DERs to the upstream markets do not cause distribution constraints and verifying the actual service provision by means of the metering data (THINK Project 2013). At the same time, this raises the issue of stronger cooperation between TSOs and DSOs

[9] See the discussion on tendering schemes for distributed energy storage systems in section 5.1.3.2.
[10] Note that since a distribution company may operate hundreds or thousands of areas where network problems may arise every day, ex-post regulatory supervision is virtually impossible.

which requires a clearer definition of the roles and data exchange among stakeholders[11]. Different models and visions for this interaction can be found in (ISGAN 2014; EU Network Operators 2015).

Recommendations:

- DSOs should be enabled to engage in the provision of flexibility services at distribution level by DER connected to their grids.
- The conventional centralized standard-based schemes should be adapted so as to take into account the specific local network conditions and needs as well as the different technical capabilities and adaptation costs of different users.
- Market-based approaches should be used to the extent possible. However, local markets for flexibilities may be hard to implement in practice due to the strong local nature of the service and the subsequent low number of potential suppliers.
- In those cases where market-based allocation is not possible or efficient, bilateral agreements between DER and DSOs are more suitable alternative. To the extent possible, these contracts should be standardized and supervised by the regulators to prevent discriminatory treatment.
- Due to the fact that ex-post regulatory supervision of these services would be excessively burdensome, an appropriate definition of the services, remuneration schemes and technical requirements ought to be pre-defined by regulators.
- DSOs should facilitate the participation of DER into upstream services and markets. This requires an enhanced interaction between TSOs and DSOs, which at the same time needs regulation to clearly define the roles and data exchange among them.

5.3.2 DER-related business models: DER aggregation, ESCOs and storage

As shown in section 4.3.2, unlocking the benefits of the growing awareness and flexibilities of distribution network users is bound to require the intermediation of new entities in order to mitigate the transaction costs faced by each individual user. These new stakeholders may correspond to ESCOs, whose main domain of action is to be found downstream of the meter (users premises), or aggregators, whose focus is placed upstream of the meters (network and system operation services). Whilst the former are widely developed in most partner countries, particularly providing energy efficiency services, the latter still show much room for growth. Likewise, the review of current regulation in partner countries has shown that the deployment of energy storage still requires defining a clear regulatory framework consistent with EU-wide legislation.

5.1.3.1 ESCOS and aggregation

Barriers:

Several of the SuSTAINABLE functionalities are affected by the degree of involvement of a third-party to unlock the flexibility of distribution network users or to provide energy services to them. This would be mostly done by aggregators and ESCOs respectively. For example, ESCOs could offer end users PQ services or microgeneration services, as actually done in some partner countries (e.g.

[11] In island systems such as the Greek scenario in this project, the situation may be different due to the fact that a vertically integrated company exists, thus simplifying this coordination.

Portugal) in addition to the more widespread energy efficiency services. Concerning aggregation, the focus so far has been placed on the upstream services, presumably since those are the activities where the revenue streams are more stable and substantial. In fact, only the UK, among the partner countries, presents truly commercially active aggregators. Furthermore, the current picture is not much better across Europe (SEDC 2015c). As these services develop, we may find aggregators searching for additional revenue streams in the distribution sector.

It is important to note that these stakeholders may be seen as roles or functions which do not necessarily have to be carried out independently, but which can be performed by the same company or even by other existing entities such as suppliers. For instance, the CBA for the VPP functionality (SF5) has evaluated two main business cases: loss reduction through ToU tariffs for end consumers and preventing DG curtailment through demand response. In the former case, the VPP would be acting both as a supplier and an aggregator. In the latter case, the VPP could be purely an aggregator managing demand flexibility.

Since these roles are to be located within the realm of competitive activities, the role of regulation is to create a level playing field that eliminates hurdles for these business models and prevent any entry barriers that incumbent agents could try to create. Nonetheless, there are certain actions that regulators do need to take in order to achieve such a goal. On the one hand, DSO revenue regulation ought to be adapted following the guidelines provided in section 5.1 so that they are encouraged to rely on flexible solutions instead of conventional network reinforcements and the regulatory mechanisms enabling this possibility should be put in place, as discussed in section 5.3.1.

On the other hand, explicit demand response mechanisms, i.e. those that do not strictly correspond to the price elasticity response to retail tariffs but to ad-hoc actions typically taken by independent aggregators to modify end-user behaviour, can cause deviations in the overall system energy settlements when this is not backed by a change in the system generation dispatch (SEDC 2015a; SEDC 2015b). This happens because such independent aggregators may not be BRPs thus not facing any penalties for deviations and no standardized procedure is in place to settle these deviation among stakeholders.

Recommendations:

- Aggregation should be enabled and promoted by regulation should the potential DER flexibility be truly unlocked. This is more pressing as Europe moves towards largely decentralized power systems based on a significant share of variable and intermittent renewable generation. These are competitive activities where the role of regulation should be to create a level playing field preventing entry barriers and discriminatory treatment.
- The successful implementation of flexibility services at distribution level is contingent upon the adaption of DSO revenue regulation and the creating of regulatory mechanisms to enable these interactions.
- The balancing responsibilities should be clearly and fairly allocated so as to prevent creating important imbalances in the system operation. Mechanisms enabling cross-settlements across BRPs and aggregators ought to be sharply defined.

5.1.3.2 Distributed storage

Barriers:

It is important firstly to remark that this section will focus on the connection of energy storage directly to the distribution network. When these technologies are connected at the premises of consumers or generators, it is clear that the ownership and operation of the storage systems is to be performed by these users. Consequently, this does not pose any problem from a regulatory viewpoint. However, in the case of storage assets directly connected to the distribution network with the goal of providing network and system services, the existing DSO unbundling rules do raise regulatory concerns. The main reason for this is that energy storage, in addition to distribution network support, may be used for competitive activities such as balancing services or price arbitrage (THINK Project 2012). Hence, the focus hereinafter would be precisely placed on this topic of storage ownership and operation.

Given the scope defined above, the subsequent discussion in mostly relevant to functionalities where energy storage is considered for the provision of network services such as voltage control, congestion management or investment deferral (SF4, SF5 and SF7). The regulatory mechanisms enabling the active participation of distributed storage would be the same discussed in previous sections for DER in general, particularly for DG units and active demand. However, this will not be possible until clear rules are defined enabling the boundaries for energy storage ownership. Among partner countries, Germany is the only where an explicit decision has been made by the regulator, by forbidding DSO owned storage. Being this one of the existing alternatives, it is not the only one that may work along DSO unbundling. The full range of alternatives are as follows:

- Prevent DSOs to own and operate storage units under any circumstance, hence being impossible for them to decide upon its location and operation. Whilst this alternative is strictly compliant with unbundling rules, it would make it very hard to storage units to be located where they are most needed from the distribution network perspective.
- Allow DSOs to own storage under several constraints related to size limitations, restricting its use for network support. A drawback of this approach is that the installed storage capacity would probably be inefficiently utilized when this is done exclusively to tackle or prevent network constraints which may happen a few hours per year (Anuta et al. 2014). Hence, the corresponding CBA would easily turn out negative.
- A third way would consist in forbidding direct DSO ownership of storage assets, but implementing additional regulatory mechanisms that enable them to influence the siting, sizing and operational decisions over these assets. This may be done through bilateral contracts between the DSO and the independent storage promoter which set out conditions for the location and grid-support services to be delivered, in exchange for a certain fee. When these contracts include conditions on the location and size of the storage systems, these should probably expand over a relatively long period of time. Thus, DSO would be provided with certainty that network investments can be deferred, whereas storage owners would receive a stable revenue stream supporting their business case. Particularly for large projects, these contracts could be allocated through competitive tenders run by the DSO under the supervision of predefined rules by the regulator. Alternative, the contracts between DSOs and storage operators could be limited to the operational stage of the project. These contracts would enable the DSO to operate the storage capacity under certain conditions defined in their

contracts. For example, DSOs may be entitled to use a predefined share of the storage capacity not needed that is unutilized for other services or during a specific number of hours per year when network constraints in the area are expected.

Among the storage ownership models discussed above, the third and last is presumably the one leading to the most efficient outcome since it can at the same time promote an efficient location and sizing of storage units to provide distribution network support and prevents violating the existing unbundling rules. However, this option is also the most complex one and presumably the one with the highest transactions costs. Therefore, constrained DSO ownership may be analyzed by regulators on a transition phase to gain experience beyond demonstration projects provided that adequate regulatory supervision is in place.

Recommendations:

- Regulation should set clear guidelines regarding ownership and operation of network-connected storage. Otherwise, regulatory uncertainty may hamper or delay storage projects.
- In its initial development, enabling DSO ownership under restricted conditions may enable a faster uptake of distributed storage. The regulatory limitations may be referred to the size of the storage units, the type of service storage systems can be used for or the operational constraints that must be observed. Moreover, DSOs may be asked to elaborate a CBA for each project or group of projects and remuneration methods adapted to allow for DSO-owned storage.
- Over the long-term, DSO-owned storage should be replaced by competitive mechanisms that promote a more efficient utilization of the storage capabilities whilst allowing DSOs to benefit from the storage potential.

5.3.3 Smart metering

Barriers:

Smart metering technologies are seen as a key enablers for the development of demand response and a pre-requisite to extend the liberalization and competition to retail at all levels of the power supply chain, particularly the small commercial and residential consumers. With these aims in mind, the European Directive 2009/72/EC (European Communities 2009) states that Member States must perform a CBA of the smart metering roll-out and reach at least an 80% of penetration by the year 2020. However, demand response, energy efficiency and retail competition are not the only benefits brought about by smart metering data and AMI. These technologies enable new functionalities that can support the planning and operation of distribution grids such as network supervision or early outage detection.

Within the scope of the SuSTAINABLE project AMI is relevant to the forecasting functionalities (SF1 and SF2) since smart meters would provide the input data required to obtain demand and generation forecasts with higher granularity, state estimation (SF3) for which metering data may be used as an additional input measurement, and all those functionalities where demand response may be used to support network management or system support (SF4, SF5 and SF7).

From a regulatory point of view, there are three main aspects which may create barriers to the realization of the aforementioned functionalities: i) smart meter deployment model, ii) meter data management, and iii) smart metering and AMI functionalities. Section 4.3.3 showed that the four partner countries analyzed in this report present significantly different regulatory models concerning these two topics. These differences can have important consequences for the deployment of smart metering and, consequently, the implementation of the associated smart grid solutions.

Concerning the **roll-out model**, regardless of the final alternative selected, a clear regulatory/policy decision should be made (including responsibilities, deployment rates and financing issues) to mitigate regulatory uncertainties that may induce "wait-and-see" situations which de facto halt the smart metering deployment. For instance, this may be taking place in countries like Portugal or Germany (European Commission 2014b). This decision should firstly determine whether a mandated large-scale, typically step-wise, roll-out is to be carried out. The main advantage of this approach is that a swifter process and less-costly technology (thanks to economies of scale) roll-out can be achieved, especially when centralized in a single agent or a reduced number of them. However, this may result in the installation of smart meters at the premises of some consumers who receive/provide little or no benefit as a result due to its low flexibility (e.g. second residences, little price elasticity, low-consumption, etc.). Furthermore, a large-scale roll-out may face opposition from some consumers due to privacy or health concerns as already happened in the case of Netherlands (European Commission 2014b).

Presumably due to these reasons, especially cost-efficiency, Germany has not implemented a large-scale mandatory roll-out as describes in section 4.3.3 for the time being. The main problem in this case is that low level of metering adoption achieved. An intermediate approach between a mandated roll-out and a market-driven deployment is to force DSOs or suppliers to offer the installation of a smart meter to all their users so as to benefit from better information, advanced tariff schemes, etc. Thus, consumers would be offered an opt-in possibility after receiving detailed information of the potential smart metering benefits. This would ensure that the roll-out observes consumer preferences. However, in spite of the enhanced information received by end users, there is still a significant risk of having relatively low adoption rates as compared to the mandated massive roll-out.

A second decision to be made when designing an approach to deploy smart meters is to determine the agents responsible for this process. The most common alternative, particularly when a massive roll-out is targeted, is to allocate this task to DSOs. This approach attains a more scalable deployment and ensures, or at least makes it easier, that the technologies deployed enable AMI to be used for network support applications in addition to commercial and retail market purposes. These further functionalities supported may include PQ monitoring, short-term forecasting, close to real-time state estimation or fault location.

Nonetheless, it is true that a DSO-oriented deployment (and data management) may lead to barriers to retail competition, particularly in countries where vertically integrated incumbents have a strong power. Therefore, clear guidelines for accessing these data ought to be defined in regulation as discussed below. This maybe even lead to a stronger supervision of the implementation of unbundling provisions. Alternatively, the deployment may be led by suppliers, as it is the case of the UK. However, a process financed by suppliers can introduce barriers for customer switching, conflicts in case of consumer change of residence or cream-skimming strategies from retailers/suppliers. Furthermore, a tighter control over the use of standards and suitable communication protocols may be required (a DSO-led deployment would ensure such standardisation at least within the DSO concession area).

As in the case of the smart metering deployment approach, regulators and policy makers may find several different alternative models concerning **metering data management**. An extensive discussion of the different models can be found in (Smart Grids Task Force 2013; CEER 2015a). A DSO-centric approach, being in line with the status quo, mitigates transaction costs and facilitates the collection of data potentially useful for network operation[12]. However, regulators may be concerned about the potential barriers for a liquid and transparent retail market functioning, particularly when there are concerns about insufficient unbundling enforcement. Thus, they may opt for a central data hub or a decentralized data access model such as the German approach. It is important to highlight that even when the DSO is in charge of installing the meters (thus benefitting from economies of scale and standardization) this does not necessarily imply that a DSO-centric data management is the only viable option (CEER 2015a).

Last but not least, regulation should address the **smart meter and AMI functionalities** necessary to unlock the different benefits offered by these technologies. In (European Commission 2012) the EC lists a number of minimum functionalities to be supported by smart meters. However, this list is neither enforced not truly comprehensive (e.g. fault location is not considered). Consequently, some solutions may be contingent upon the decisions of NRAs or DSOs. It is important to highlight that these discussions typically focus on the data needed for billing, tariff design and, sometimes, network planning. This implies that network operation functionalities or consumer data access could be neglected, thus hindering several of the SuSTAINABLE functionalities.

Recommendations:

- The lack of a clear deployment framework may delay the deployment of AMI. This, in addition to being a barrier for some smart grid applications, can hamper retail competition to supply small consumers. Therefore, Member States where AMI deployment is pending due to a negative or inconclusive CBA ought to reassess these so as to ensure incorporate all the potential benefits these technologies offer are included.
- Different smart metering deployment and data management models exist. In principle, none of them is necessarily superior to the rest. However, it is important that regulators ensure that, regardless of the approach implemented, consumption data is provided to market agents (suppliers, aggregators, ESCOs) and consumers in a transparent and non-discriminatory way.
- Furthermore, metering data that could be applied for distribution network operation should be made available to DSOs in the time scales required. This could be applied to other functionalities such as remote connection/disconnection or meter tampering detection. A DSO-centric approach may facilitate the latter, but may not be advisable in case insufficient unbundling is seen as a potential barrier for retail competition.
- The smart metering deployment model and the data management model should be designed consistently and attending to the particular size and structure of the country's distribution and retail sectors. Furthermore, policy-makers and regulators must bear in mind the existing trade-offs so as to select the model that best suits their priorities (e.g. ensure a fast deployment,

[12] The major difference in the use of metering data for network planning and operation is related to the time-scales involved. Whilst data for network planning may be required by the DSO every month or every few months, using metering data for fault location or state estimation involves a time scale in the order of seconds.

focus on the promotion of retail competition, address social opposition to smart metering, etc.).

- Smart metering and AMI functionalities should be clearly defined by regulation to promote a swifter and less costly roll-out enabled by standardization and regulatory certainty, whilst ensuring that all potential (cost-effective) smart metering benefits and applications are enabled. This topic can be particularly relevant now that several EU countries still have to roll-out smart metering and others are about to carry out the deployment of a second generation of smart meters.

6. Summary and conclusions

The goal of this report was to provide regulatory recommendations so as to facilitate an efficient deployment of the smart grid functionalities and use cases tested and evaluated within the SuSTAINABLE project. Therefore, the results presented herein can be seen as a complementary work to the cost-benefit analysis and the scalability and replicability analysis presented in other deliverables.

In order to achieve this goal, the different functionalities and use cases were mapped against a list of relevant regulatory topics that had been previously identified. This exercise allows identifying which of the regulatory recommendations contained in this report would be relevant to each specific smart grid solution. For the sake of illustration, and to provide more concrete examples and applications, a set of four partner countries have been analyzed in detail. In line with other works within the project, these countries have been: Portugal, Greece, UK and Germany.

Lastly, the core of this report consists in an identification of barriers and bottlenecks for the deployment of the previous smart grid solutions and the issuing of regulatory recommendations aiming to overcome these. The results of this review per topic as well as the final set of recommendations provided in this report are summarized in Table 3.

Regulatory topic	Functionalities/use cases affected	Recommendations
DSO economic regulation		
Revenue regulation	All	- Implement neutral CAPEX-OPEX incentives - Adopt forward-looking cost assessment methodologies and detailed investment plans - Introduce flexibility mechanisms in remuneration formulas - Assess extending the length of regulatory periods - Progressively shifting the focus of regulatory supervision from investment adequacy to the outputs delivered
Regulatory incentives		
Continuity of supply	SF3,SF9,UC1	- Implement incentive-penalty schemes for DSOs to improve network reliability addressing both the number and duration of interruptions - Symmetric incentives without dead-bands are advisable. Caps and floors mitigate DSO risk. These parameters should be reviewed and updated periodically - Incentive rates should be based on a detailed assessment of the marginal cost of improving reliability and the cost of interruptions for consumers
Energy losses	SF4, SF5,SF8	- Rely on smart metering to improve loss accuracy and fine-tune incentives - Symmetric incentives without dead-bands are advisable. Caps and floors mitigate DSO risk. These parameters should be reviewed and updated periodically - Reference losses should incorporate the impact of DER on each area - Incentives should expose DSOs to the quantity risk but not to price risks, since the unit cost of losses is non-controllable by them - Incentive rates (value of losses) should be set ex-ante and reflect the full value of losses
Other output-based incentives	SF4,SF5,SF6,SF7,SF8	- Bonus-malus schemes are suitable for controllable indicators as long as these are objectively and transparently measurable - Progressive transitions before full DSO exposure to incentives/penalties are recommended -Otherwise, regulators should explore the use of additional output indicators and alternative applications
DSO innovation incentives	All	- Advisable to spur demonstration activities. These ought to include knowledge-sharing and information disclosure obligations - Their design should be consistent with the overall DSO regulation to avoid a double payments or other inefficeincies - Input-oriented mechanisms should evolve towards implicit incentives

Economic signals for DG		
Distribution network charges	SF4,SF5,SF7	- Deep connection charges should be abandoned in favour of shallowish or shallow methods - Transparent and objective rules are recommended to prevent (actual or perceived) discrimination - UoS charges should be paid by all distribution network users in a technology-neutral manner - Capacity-based UoS charges are recommended for DG. This tariff should be differentiated in time and location
Remuneration schemes for DG	SF4,SF5,SF7	- Flat FITs or high FIPs hamper the active DG participation. Support levels should reflect costs - Self-consumption should be promoted. It encourages demand response, storage and small-scale DG and helps raise consumer awareness and participation - Net-metering should be abandoned in favour of instantaneous self-consumption schemes - Excess production should be valued according to the value of energy in each time period - Smart metering and a cost-reflective tariff design are essential for an efficient diffusion of self-consumption
DER services/business models		
Mechanisms for DER service provision	SF4,SF5,SF7,SF8	- DSO-DER interactions should be enabled to exploit distributed flexibility - Centralized standard-based schemes neglect the specific local network conditions and heterogeneity across users - Market-based approaches should be used to the extent possible - When market-based allocation is not possible or efficient, bilateral agreements between DER and DSOs are more suitable alternative - These contracts should be standardized and supervised by the regulators - DSOs should facilitate the participation of DER into upstream services and markets through interacting with TSOs. Regulation ought to clearly define the roles and data exchanges
Aggregation-VPP, ESCOs and storage		
ESCOs and aggregation	SF5,SF7	- Aggregation should be enabled and promoted. Regulation should create a level playing field preventing entry barriers and discrimination - Flexibility services at distribution level require adapting DSO regulation and enabling regulatory mechanisms - Balancing responsibilities should be clearly and fairly allocated to prevent creating important imbalances with explicit demand response
Distributed storage	SF4,SF5,SF7	- Clear guidelines on ownership and operation of network-connected storage are necessary - Restricted DSO ownership subject to a CBA could be adopted initially - Over the long-term, DSO-owned storage should be replaced by competitive mechanisms that promote a more efficient utilization of the storage capabilities whilst allowing DSOs to benefit from the storage potential
Smart metering	SF1,SF2,SF3,SF4,SF5,SF7	- A clear deployment framework for AMI is required. Member States where AMI deployment is pending due to a negative or inconclusive CBA ought to reassess these to incorporate all the potential benefits are included - No model is necessarily superior to others. Regardless of the approach, regulation should ensure that consumption data is provided to market agents and consumers in a transparent and non-discriminatory way - Metering data for network operation should be available to DSOs in the time scales required - Smart meter deployment and data management models should be consistent and reflect the country's context and policy priorities - Smart metering and AMI functionalities should be clearly defined by regulation to promote a swifter and less costly roll-out enabled by standardization and regulatory certainty

Table 3: Summary of regulatory topics and recommendations

References

SuSTAINABLE project documents

Deliverable 2.3. Definition of Overall System Architecture. Lead beneficiary: EFACEC.

Deliverable 3.6. Methodology for provision of differentiated QoS. Lead beneficiary: UNIMAN.

Deliverable 7.1. Cost and benefit analysis in the SuSTAINABLE demos. Lead beneficiary: Comillas.

Deliverable 7.3. Economical interactions of entities controlled by VPP for providing potential services to enhance the operation of distribution networks. Lead beneficiary: TU Berlin.

Deliverable 8.2. Scaling-up and replication rules considering the requirements and local conditions in demo sites. Lead beneficiary: Comillas.

Deliverable 8.3. Roadmap and proposals of the SuSTAINABLE concept in an effective macro-scale replication. Lead beneficiary: TU Berlin.

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