JRC SCIENTIFIC AND TECHNICAL RESEARCH

Guidelines for Cost Benefit Analysis of Smart Metering Deployment

Vincenzo Giordano, Ijeoma Onyeji,
Gianluca Fulli (JRC IET)
Manuel Sánchez Jiménez,
Constantina Filiou (DG ENER)

2012

Report EUR 25103 EN

Joint Research Centre

European Commission
Joint Research Centre
Institute for Energy and Transport

Contact information
Gianluca Fulli
Address: Joint Research Centre, Westerduinweg 3, 1755 LE Petten, The Netherlands
E-mail: gianluca.fulli@ec.europa.eu
Tel.: +31 224 56 5266

http://iet.jrc.ec.europa.eu/
http://www.jrc.ec.europa.eu/

JRC67961

EUR 25103 EN

ISBN 978-92-79-22323-5

ISSN 1831-9424

doi:10.2790/39435

Luxembourg: Publications Office of the European Union, 2012

JRC SCIENTIFIC AND TECHNICAL RESEARCH

Guidelines for Cost Benefit Analysis of Smart Metering Deployment

Vincenzo Giordano, Ijeoma Onyeji,
Gianluca Fulli (JRC IET)
Manuel Sánchez Jiménez,
Constantina Filiou (DG ENER)

2012

Report EUR 25103 EN

Joint Research Centre

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Goal of the report

The goal of this report is to provide guidance and advice for conducting cost benefit analysis of smart metering deployment.

We present a step by step assessment framework based on the work performed by EPRI (Electric Power Research Institute), and we provide guidelines and best practices. Several additions and modifications to fit the European context have been proposed. This work draws on the existing collaboration between the EC and the US Department of Energy (DoE) in the framework of the EU-US Energy Council.

The assessment framework is structured into a set of guidelines to tailor assumptions to local conditions, to identify and monetize benefits and costs, and to perform sensitivity analysis of most critical variables. It also provides guidance in the identification of externalities and social impacts that can result from the implementation of smart metering deployment but that cannot be easily monetized and factored into the cost benefit computation.

This study represents the application to the specific case of smart metering deployment of the general guidelines for conducting a cost benefit analysis of Smart Grid projects [EC 2012b].

Policy relevance

The Directive on the internal markets 2009/72/EC [European Union 2009] encourages Member States to deploy Smart Grids and smart metering systems (article 3). Such deployment might be subject to long term CBA, as mentioned in the ANNEX I of the Directive.

The recent EC Communication on Smart Grids [EC, 2011a] explicitly states that the Commission intends to come up with guidelines on the CBA to be used by the Member States to fulfill the provisions in the Annex 1 of Directives 2009/72/EC and 2009/73/EC for the roll-out of smart metering systems. In a second step, the Commission also intends to release guidelines for a CBA for the assessment of Smart Grid deployment.

Finally, the Commission "Proposal for a Regulation of the European Parliament and of the Council" recommends the implementation of Smart Grid projects in line with the priority thematic area "Smart Grids deployments". One of the criteria of eligibility for Smart Grid projects is their economic, social and environmental viability, which calls for a definition of a comprehensive impact assessment methodology, including a cost-benefit analysis.

This study contributes to fulfill this need. In particular, it serves as a scientific reference for the CBA section of the EC Recommendations on smart metering deployment [EC 2012a].

1 INTRODUCTION

1.1 BACKGROUND – POLICY CONTEXT

The European Commission (EC) adopted a policy paper on Smart Grids in April 2011 [EC 2011a]. The paper charted out the vision of integrated infrastructure management which will allow the markets for electricity and gas to evolve further, in particular to allow the uptake of renewable energy, also produced at micro level, in order to increase security of the networks, create opportunities for energy saving and energy efficiency and give a more active role to energy consumers in a liberalized energy market. Smartening Europe's electricity grids is a precondition to make these changes happen [EC 2011b]. The Smart Grid concept and its relevance for energy policy goals will be further elaborated on in the upcoming Commission policy documents planned for 2012, such as the Internal Energy Market and the Renewable Energy Sources communications.

The Electricity Directive 2009/72/EC and the Gas Directive 2009/73/EC on internal markets (Annex I) set up the framework for the roll-out of smart metering systems, which states that EU Member States should ensure the implementation of smart metering systems that shall assist in allowing active participation of consumers in the electricity and gas supply market. Provisions of these Directives foresee that the roll-out of smart metering systems in a Member State may be subject to an economic assessment of all the long-term costs and benefits to the market and the individual consumer. In that case, cost-benefit analysis (CBA) for the implementation of smart meters should be carried out before 3 September 2012. In the case of electricity, where an economic assessment of the long-term costs and benefits has been made, at least 80 percent of those consumers who have been assessed positively, have to be equipped with smart metering systems by 2020 [EU 2009].

A specific set of initiatives is required with respect to the roll-out of functional smart metering systems which are essential for the deployment of Smart Grids while representing an important means of customer empowerment. As such, smart metering systems specifically feature not only in the consumer-related provisions in the 3rd energy package but also in the more recent proposal for an Energy Efficiency Directive

(EED) currently in the legislative process. The EED should usefully complement the provisions of the 3rd energy package to further stimulate the roll-out of smart metering systems in the present decade.

Several Member States have already progressed well in the preparation of the roll-out of smart metering systems by the elaboration of cost-benefit analyses (CBA) [Kema 2010; Atkearney 2010; CER 2011; PwC Österreich 2010]. The lessons learnt from that experience point to some good practices as regards CBA methodologies and structures. They also show the importance of defining some common-minimum functionalities for smart metering systems. As more Member States (MS) are likely to engage in similar CBAs in the near future, it appears necessary to urgently provide common guidelines to ensure that CBAs of individual MS are comparable, relevant and based on comprehensive and realistic deployment action plans.

The Commission Recommendations [EC 2012a] set key requirements for data privacy and data security, for the general methodology of CBAs and for common-minimum functionalities of smart metering systems, highlighting the importance of the inclusion of scenarios/options going beyond the bare common-minimum set of functionalities. The provisions of such Recommendation have been built on the experience of the early-riser Member States, but also take account of expert work carried out in the Smart Grids Task Force led by the Commission [EC Task Force for Smart Grids , 2010a 2010b 2010c].

1.2 GOAL OF THE SMD GUIDELINES

The present document provides methodological guidelines and best practices for conducting a CBA of smart metering deployment (SMD). The assessment framework is structured in a set of guidelines to tailor assumptions and parameters to local conditions, to identify and monetize benefits and costs, and to perform sensitivity analysis of most critical variables. It also provides guidance in the identification of project impacts and externalities that can result from the implementation of Smart Grid projects but cannot be easily monetized and factored in the cost benefit computation.

This document is intended to facilitate fulfillment of the provision of the 3rd energy package on CBA for SMD by Member States. Its task is to support the work of the Member States and to foster coherence in the assessment of SMD scenarios throughout Europe. The proposed framework will also be used by the Commission to analyze and benchmark the CBA performed by Member States.

We remark that the content of our guidelines has to be seen as a structured set of suggestions, as a checklist of important elements to consider in the analysis. A good comprehensive analysis of SMDs requires adaptation to local circumstances and will ultimately rely on the professional skills and judgment of project developers and relevant decision makers. It is not our goal to provide an exhaustive and detailed set of indications to fit all possible scenarios and local specificities.

1.3 GENERAL APPROACH TO THE CBA OF SMART METERING DEPLOYMENT

In setting up the guidelines for the CBA (see [EC 2012b] for more details), our more general target is an economic-oriented CBA, which goes beyond the costs and the benefits incurred by the actor/s carrying out the SMD. Our guidelines ultimately aim at taking a societal perspective in the CBA, considering the project impact on the entire electricity system and on society at large.

Also, the proposed approach recognizes that the impact of SMD goes beyond what can be captured in monetary terms. Some of the impacts can be quantified and included in a CBA, whereas others need to be included among externalities and addressed qualitatively.

Another critical element to bear in mind when conducting the SMD analysis is that smart metering systems represent a piece of a larger Smart Grid proposition. Synergies between smart metering and Smart Grid capabilities can significantly enhance the impact of SMD and promote their business case [KEMA 2010]. We recommend considering the impact of these potential synergies in the analysis. Integrating smart metering systems within a broader Smart Grid implementation can be much more costly if the Smart Grid option had not been considered at the time of the SMD.

In this context, our general approach to CBA of SMD aims at integrating two main assessment perspectives: an economic analysis (monetary appraisal of costs and benefits on behalf of society) and a qualitative impact analysis (non-monetary appraisal of non-quantifiable externalities and impacts, e.g. social impacts, contribution to policy goals).

Economic analysis: Monetary appraisal

The economic analysis takes into account all costs and benefits that can be expressed in monetary terms, considering a societal perspective. In other words, the analysis should try to also include costs and benefits that spill over the smart metering scenario into the electricity system at large (e.g. enabling the future integration of distributed energy resources; impact on electricity prices and tariffs etc.) and into society at large (e.g. environmental costs; consumer inclusion).

To what extent these additional benefits and costs might ultimately be internalized and included in the CBA depends on how defensible the calculation of their euro equivalent is.

The proposed approach to CBA is composed of three main parts (see Figure 1):

- definition of boundary conditions (e.g. demand growth forecast, discount rate, local grid characteristics) and of implementation parameters (e.g. roll-out time, smart metering functionalities)
- identification of costs and benefits
- sensitivity analysis of the CBA outcome to variations in key variables

To this end, this report aims at providing:

- insights to choose key parameters
- a systematic approach to link deployed assets with benefits
- a possible (non exhaustive) set of formulae to monetize benefits
- an indication of most relevant costs incurred in a smart metering deployment

- illustration of a sensitivity analysis to identify critical variables affecting the CBA outcome

The main goal of the economic analysis is to extract the range of parameter values enabling a positive outcome of the CBA and define actions to keep these variables in that range. Possible output indicators of the CBA outcome include:

- √ Economic net present value (ENPV): the difference between the discounted benefits and costs, considering a society perspective
- √ Economic internal rate of return (ERR): the discount rate that produces a zero value for the ENPV
- √ B/C ratio, i.e. the ratio between discounted economic benefits and costs

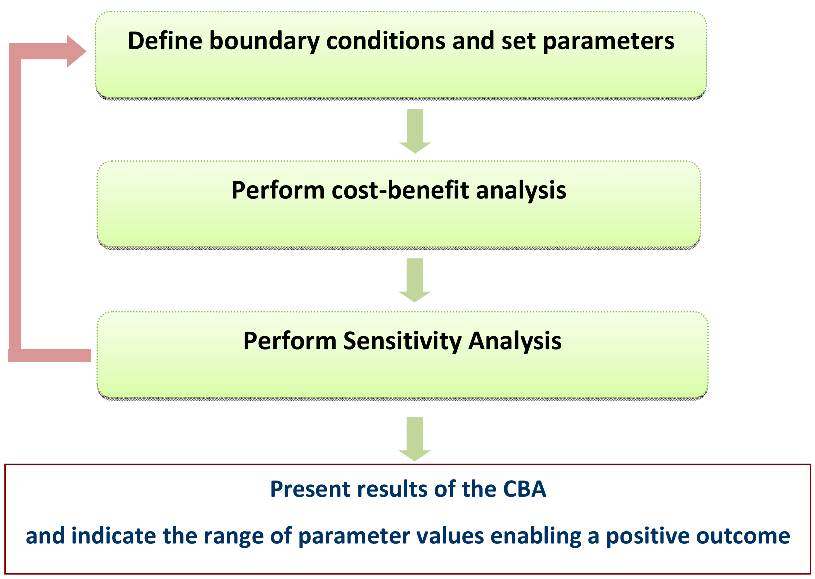


Figure 1 Cost-Benefit Analysis Framework

Qualitative impact analysis: Non-monetary appraisal

The overall analysis should also consider impacts that are not quantifiable in monetary terms. This requires assessing (i) the deployment merit of the SMD in terms of contribution to expected outcomes and policy objectives (e.g. security of supply, improvements to market functioning) and (ii) additional impacts (externalities) spilling over from the SMD (e.g. enabling new services and applications; social impacts in terms of consumer inclusion and job creation).

All items of the non-monetary appraisal should be listed and expressed in physical terms or through a qualitative description, in order to give decision makers the whole range of elements for the appraisal.

Combining monetary and non-monetary appraisals

Once the outcomes of the economic analysis and of the qualitative impact analysis have been assessed, it is necessary to specify:

- √ Weights to combine the different impacts of the qualitative impact analysis (see guideline 10 for more details). The weights should reflect the relative importance of each item in the decision maker's view.
- √ Suitable weighting factors to combine the quantitative and qualitative analysis (see Figure 2).

The appraisal report should argue convincingly, with the support of adequate data, on the choice of the weights.

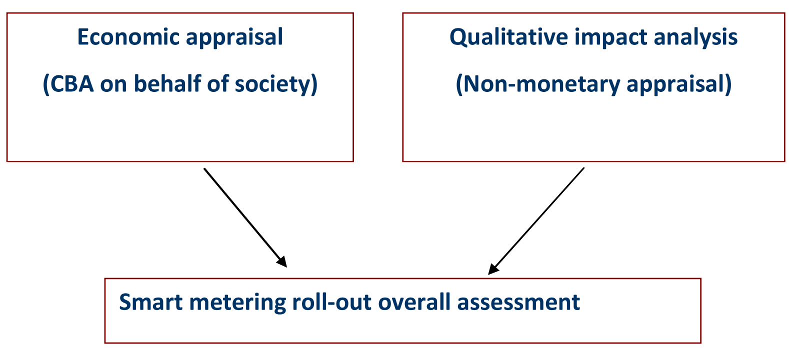


Figure 2 Assessment framework of the smart metering roll-out, including economic and qualitative impacts

In summary, our assessment framework aims at capturing four different sources of impacts resulting from a SMD:

1) Benefits resulting directly from the smart metering implementation (e.g. reduction of remote reading costs and energy savings due to consumption feedback)

2) Reduced costs in future Smart Grid implementations (e.g. future investments in Smart Grid capabilities to cope with high level of penetration of Distributed Energy Resources can benefit from an existing smart metering infrastructure) through the use of the smart metering infrastructure. In order to reap this benefit, it is necessary, however, that smart metering functionalities and communications performance deployed today are not only adequate for smart metering purposes but can also support future Smart Grid functionalities/technologies as real-time demand side management, distribution automation etc. (see e.g. [KEMA 2010])
3) Benefits enabled by the installation of smart metering systems (e.g. reduction of outage time, reduction of technical losses and network operational efficiencies), but that require the implementation of additional Smart Grid capabilities (e.g. Distribution Automation (DA), Real-time Demand side management (DSM) etc.) to be reaped
4) Other impacts of SMD which have an effect on the public or society at large that might be difficult to capture quantitatively (more details in guideline 10); in this class of benefits, we include social impacts (e.g. consumer inclusion, social acceptance, job creation) and contributions to achieving strategic policy goals (e.g. security of supply, functioning of the electricity market etc.).

2 ASSESSMENT FRAMEWORK

The core of our assessment methodology is expressed by the definition of a CBA approach. The proposed CBA (for further details please refer to [EC 2012b]) draws on the work by [EPRI 2010] and consists of the seven steps detailed in Figure 3.

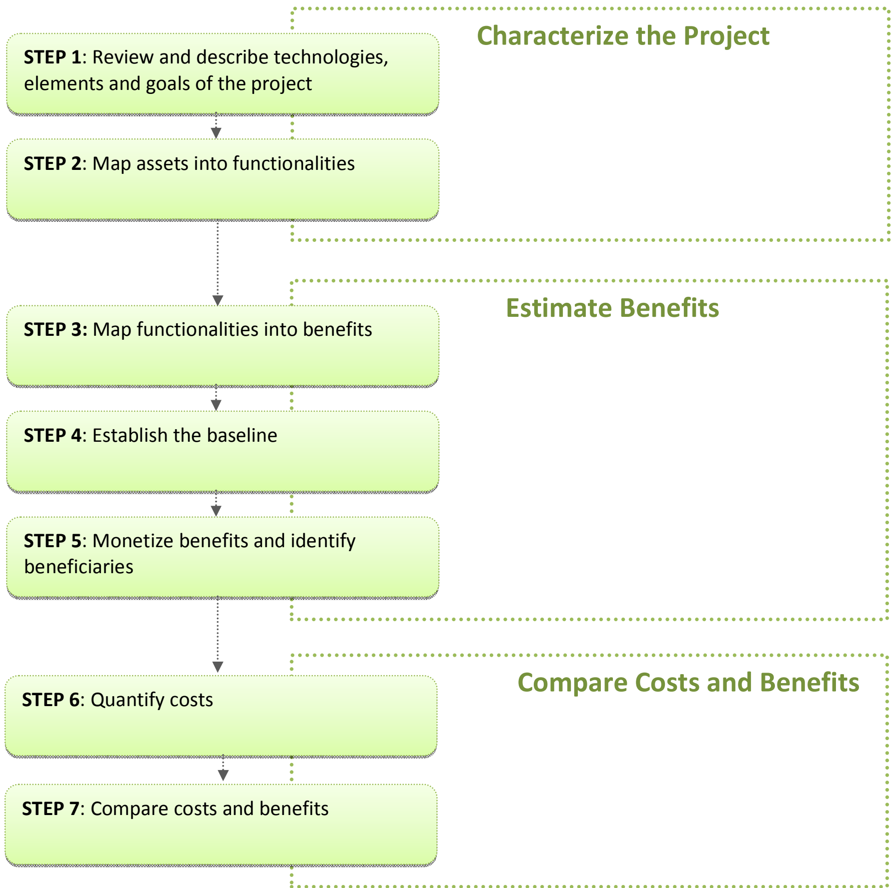


Figure 3 Seven steps of the CBA

The main idea of the proposed methodology is that assets provide a set of functionalities that in turn enable benefits which can be quantified and eventually monetized (Figure 3). These functionalities refer to Smart Grids in general [EC Task Force for Smart Grids, 2010a] and should not be confused with the smart metering minimum functionalities [EC 2012a, EC 2011c] presented in ANNEX V and discussed in section 2.1. In this context, smart metering systems are considered as one of the possible Smart Grid assets.

In our modified version of the methodology, we propose to map (i) assets into functionalities, (ii) functionalities into benefits and (iii) benefits into monetary values. Step 2 is the first of the three 'mappings', which are depicted in Figure 4 and represent the key steps undertaken in this analysis.

The relevance of these mapping exercises rests on two factors: (i) they assist in thinking of sources of benefits, making a complete set of estimated benefits more likely, and (ii) they make possible the evaluation of the 'smartness' of a scenario through specific key performance indicators proposed by [EC Task Force for Smart Grids , 2010a 2010c].

For Smart Grid projects, where several different assets and capabilities might be involved, the links between assets and benefits through functionalities are tangled and not univocal [EC, 2012b]. For smart metering implementation, this exercise is more straightforward.

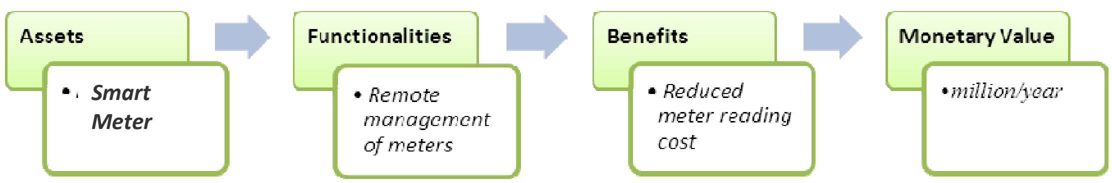


Figure 4 From assets to monetary value

2.1 SCENARIOS FOR SMART METERING ROLL-OUT

The results of a CBA for a smart metering roll-out depend on implementation scenarios, including the number of implemented smart metering functionalities and the ability to enable Smart Grid functionalities. Three main variables should be considered in defining a roll-out scenario: the percentage of the smart meters to be installed (e.g. 80%), the roll-out time (e.g. 2020) and the number of smart metering functionalities considered. Based on best practices of early CBA carried out in eleven Member States, the EC has recently provided guidance and set up of common-minimum smart metering functionalities for electricity [EC 2012a, EC 2011c] (see ANNEX III).

We recommend performing a cost benefit analysis considering as a minimum the following two scenarios (see table 1):

- Scenario 0: 'Business as usual'- BaU, no roll-out of smart meters. In this scenario, it is also assumed that, independently from a Smart Meter roll-out mandate, no smart meters will be installed in the CBA time horizon. In other words, it is assumed that there is no point in time in which, for market reasons, utilities/meter operators choose to buy and install smart meters over traditional meters. This might also be labeled as the "Do nothing and nothing happens" scenario.
- Scenario 1: roll-out of 80% of Smart Meters endowed with minimum set of functionalities, by 2020. This scenario corresponds to the minimum provisions defined in the 3rd energy package, which prescribes the roll-out of at least 80% of smart meters by 2020 in case of positive CBA. In this scenario, the Smart Meters are provided with the agreed set of common minimum functionalities.

Other scenarios should also be considered by varying the three main variables, which account for different possible choices in the implementation of the roll-out. We recommend the inclusion of scenarios going beyond the bare common-minimum set of functionalities. Depending on data availability, a more granular description of the scenarios might be carried out, e.g. differentiating the percentage of household and industry consumers, segmenting household consumers in terms of energy consumption, making hypothesis on the density of the areas where the roll-out will take place (e.g. the roll-out will mainly target urban areas rather than rural).

The CBA framework presented in chapter 3 should be followed to assess the outcome of each scenario against the baseline (scenario 0).

Scenario	Extension of roll-out (percentage of consumers)	Roll-out time (ending year)	Number of Smart Meter functionalities
Scenario 0 (business as usual)	-	-	-
Scenario 1 (3rd energy package scenario)	80%	2020	10 common - minimum functionalities [EC 2012a, EC 2011c]

Table 1 - Basic scenarios to consider for the CBA

3 GUIDELINES FOR CBA OF SMART METERING DEPLOYMENT

In this chapter, we are providing guidelines to perform a comprehensive CBA assessment of smart metering roll-outs. The guidelines cover five main macro-steps (see Figure 5):

1) Definition of the scenario

2) Within the scenario: definition of assumptions, critical variables and boundary conditions tailored to the specific geographical/economical/regulatory context

3) Implementation of the CBA

4) Implementation of a sensitivity analysis to analyze the influences of key variables on the estimations calculated in the macro-step 2

5) Integration of the CBA with the qualitative assessment of the merit of the deployment (performance assessment), externalities and social impact.

The process is iterative in the sense that during calculations it could prove necessary to retune the assumptions or to collect more data and repeat the analysis.

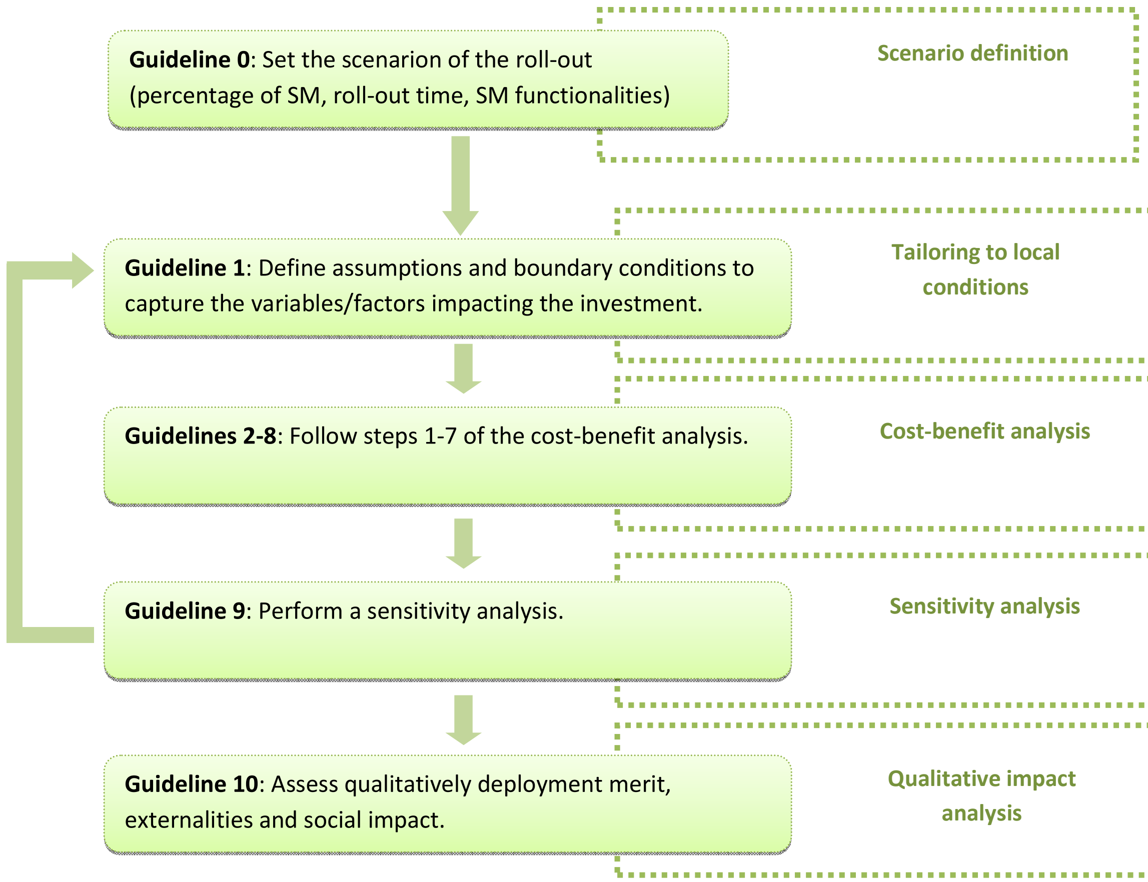


Figure 5 Guidelines flow chart

3.1 SET-UP THE SCENARIO

Guideline 0 - Define the scenario

Define the scenario of the smart metering roll-out, by setting the percentage of the smart meters to be installed, the roll-out time and the number of smart metering functionalities considered.

As described in section 2, we recommend considering at least scenarios 0 and 1. In addition, we strongly recommend to consider additional scenarios, taking into account other variables, like consumer types (percentage of households and industry consumers, composition of household consumers in terms of energy consumption), and density of deployment (e.g. urban areas vs. rural) and the inclusion of scenarios going beyond the bare common-minimum set of functionalities. Other scenarios might explicitly consider the implementation of Smart Grid capabilities in synergy with smart metering systems. As discussed above, it is good practice to plan the Smart Metering deployment with a Smart Grid architecture in mind in order to fully reap long-term benefits. For example: With some technical architecture, where PLC (power line communication) is the dominant communication technology, it might be strategically convenient to pursue a Smart Grid architecture from the beginning, as PLC demands installation of equipment at the secondary substation level that can be easily upgradable to a Smart Grid configuration. This means that the decision to install additional Smart Grid capabilities may be made at minimum marginal cost.

3.2 TAILORING TO LOCAL CONDITIONS

Guideline 1 – Define assumptions and set critical parameters

Scenario coordinators should adapt assumptions to local conditions. Different geographies and contexts will determine the impacts on the quantification of benefits.

Some recommendations:

- Identify and list the main parameters defining the local context/conditions of the roll-out
- State clearly and substantiate the major assumptions, describing how they are influenced by local conditions.
- Identify the data sources used for making assumptions and quantifying variables and specify the level of uncertainty (high, moderate, low).
- Specify the span of years in which the benefits and costs occur. Explain why this time period is the most appropriate one.

Table 2 reports a representative and non exhaustive list of variables/data to be set/collected within the CBA timeframe to capture the factors potentially having an impact (positive or negative) on the investment.

Variables/data to be set/collected	Unit
Projected variation of energy consumption	%
Projected variation of energy prices	%
Peak load transfer	%
Electricity losses at transmission and distribution level	%
Estimated non-supplied minutes	Number of minutes
Value of Lost Load; value of supply	€/kWh
Discount rate	%
Hardware costs (e.g. smart meter, GPRS/PLC modem, etc.)	€
Number of smart meters to be installed	Number of smart meters
Installation costs for smart metering system	€
Life expectancy of smart metering system	Number of years
Meter reading costs	€/year
Telecommunication success rate	%
Inflation rate	%
Cost reduction associated with technology maturity	%
Implementation schedule	Number of smart meters/year
Percentage of meters placed in rural vs. urban areas	%
Carbon costs	€/ton

Table 2 - List of some of the variables to be defined/assessed during the 'tailoring to local conditions' phase

In the following sections, we will analyze in more detail some of these critical variables. Wherever appropriate, a sensitivity analysis should be considered (see guidelines 9).

3.2.1 Synergies with Smart Grid capabilities

As mentioned earlier, new indirect benefits can result from the smart metering infrastructure when properly integrated with additional Smart Grid capabilities: network asset monitoring, aggregation services (e.g. demand response, vehicle-to-grid services), electric mobility, etc. In the definition of synergies between smart meters and Smart Grid capabilities we recommend to look into the following issues:

1) To what extent will the installation of a smart metering infrastructure reduce the costs of envisioned Smart Grid investments in the future (e.g. future Smart Grid implementation to support the penetration of distributed energy resources will make use of the smart metering infrastructure installed today)? To this aim, it should be considered at what time these saved investments would take place (e.g. depending on the timeframe of the penetration of distributed energy resources) and whether the lifespan of the installed smart metering system is compatible with that timeframe. In that case, the avoided investment in future communication infrastructure to cope with future Smart Grid developments should be considered in the CBA of the SM investment carried out today.

2) To what extent can the integration of smart metering systems with additional Smart Grid capabilities bring additional benefits? The additional Smart Grid capabilities to be implemented together with smart metering systems and their contribution to the resulting additional benefits that may be reaped should be clearly spelled out.

3.2.2 Discount rate

The discount rate takes into account the time value of money (the idea that money available now is worth more than the same amount of money available in the future because it could be earning interest) and the risk or uncertainty of the anticipated future cash flows (which might be less than expected).

The discount rate typically has a significant impact on the assessment of Smart Grid scenario. This is because (i) costs are incurred predominantly at the beginning of the scenario, while (ii) Smart Grid interventions often provide benefits only in the long-term. Moreover, if the discount rate is to give a fair reflection of the relative risk of the projects, then a higher discount rate should be applied to “smart investments”, which have a higher risk level than conventional utility investments. In this case, however, discounting could lead to seriously undervaluing Smart Grid benefits, particularly systemic benefits that often come into play only over long time periods.

A public policy discount rate (i.e. the lowest rate at which "society" can borrow money in the long-term, excluding short term volatilities) might be used. The rationale for choosing a public policy discount rate is to recognize the societal value of Smart Grid investments, whose impacts go beyond project developers and affect a wide range of stakeholders and society at large. In this perspective, it would be appropriate for the discount rate to reflect the risk to the state, specified by the state body responsible for determining whether the project will be publicly funded, in which case the project developer (e.g. the system operator) would be merely the implementing body contracted by the state, with funding for the project guaranteed.

Discounting costs and benefits at this "social" discount rate would provide the value of the project for the society, regardless of the actual project funding costs. In most countries where the utilities' weighted average cost of capital is higher than the societal discount rate, the cost of remuneration of this new investment (RoR rate over an increased remunerated assets base) and changes on operational cost impacting the tariffs might be included as an additional cost of the project in the CBA.

At the European level, social discount rates of 3.5%, 4% and 5.5% have been suggested [EC 2008; EC 2009]. Different values may, however, be proposed and justified, for example on the basis of the specific Member State's macroeconomic conditions and capital constraints. Notwithstanding, national regulators need to validate the choice of the discount rate and different views can arise in different Member States.

In any case, a clear and motivated explanation of the choice made should be provided. The discount rate should always be subject to a sensitivity analysis (see guideline 9).

3.2.3 Schedule of implementation

The implementation schedule, specifically the timeframe within which consumers are equipped with smart meters, might have a significant impact on the analysis results.

Different implementation schedules might have different impacts for different stakeholders.

One possible scenario is that net benefits decrease as the implementation rate increases. This might be the case when a particular choice of discount rate values earlier initial costs much higher than benefits that are reaped at a later point in time.

However, different variables such as “estimated inflation”, “evolution of energy prices”, “decrease in costs due to technology maturity” or applied “discount rate” may lead to higher net benefits with a fast installation rate. As a rule, when total benefits of each individual installation outweigh its costs (i.e. IRR per smart meter is higher than the discount rate), the sooner the installation occurs, the higher the NPV of the installation will be.

If possible, the schedule of implementation should also be further segmented into urban and rural implementations. Urban and rural installation might have different installation costs (euro/meter/day), and different implementation schedules for urban and rural installations (in terms of installed meter/day) might affect the final cost-benefit result.

Another important factor relating to implementation is whether the deployment campaign is “concentrated” (e.g. the entire network/city, then another etc.) or “scattered” (e.g. only clients with higher consumption in each network). Such a decision is related to the choice of telecommunication technology and potential benefits. For example: PLC is a mesh technology, where each smart meter acts as a repeater of other smart meters and therefore demands “concentrated” deployments. On the other hand, GPRS technology works well in scattered deployments (as it is a point-to-point technology). Also, whether an LV network is deployed fully or only partially will have an impact on potential network related benefits (in a Smart Grid scenario), such as reduction of technical losses, maintenance, etc.

Finally, in defining the installation schedule, it is advisable to avoid installation peaks to allow for a better management of supply chains and installation teams (this will also prevent peaks in the future, when the smart meters end their expected lifetime). The occurrence of installation peaks might generate additional costs that should be taken into account in the CBA.

The deployment timeframe, the expected lifetime of the smart meter, the number of meters installed per day, and the composition of the deployment (urban vs. rural; concentrated vs. scattered implementation) are all good candidate variables for a sensitivity analysis (see guideline 9).

3.2.4 Electricity demand and prices

Electricity demand depends on the development of other factors, such as population growth, domestic consumption, non-domestic consumption, electricity losses and electricity demand growth. It is advisable to base the choice of electricity demand or demand growth on country-specific forecasts.

Electricity price developments should also be taken into account. Since electricity savings is typically one of the most significant benefits resulting from the smart metering implementation (e.g. [KEMA 2010]), an increase in the electricity price would result in a potentially higher monetary benefit in terms of electricity savings.

Both electricity demand and electricity price forecasts have obviously a large impact on the outcome of the CBA and should therefore be subject to the sensitivity analysis (see guideline 9).

3.2.5 Technology maturity

Cost reduction associated with technology maturity needs to be taken into account in order to make estimates as accurate as possible. The latter is important as international penetration of smart metering technologies results in price reductions in real terms.

3.2.6 Carbon costs (CO2 emission costs)

Another important element is the estimation of the carbon costs throughout the scenario timeframe. In cases where the analysis permits the calculation of costs and benefits of resulting changes to carbon emissions, it is recommended that the analysis considers the carbon prices projected both in the Commission reference and decarbonisation scenarios[1].

3.2.7 Estimation of peak load transfer and consumption reduction

The percentage of *peak load transfer* represents the share of electricity usage that is shifted from peak periods to off-peak periods. This is an important variable as demand for electricity is generally concentrated in the top 1% of the hours of the year [Faruqui, 2010]. Therefore, 'shaving off' peak demand would postpone, reduce or even eliminate the need to install very expensive and highly polluting peak generation capacity. Depending on the incentives a scenario provides for shifting peak load to off-peak hours (e.g. demand response through various forms of dynamic pricing), scenarios can achieve up to 30% peak load transfer [Faruqui, 2010]. Other recent experiences show an average peak load shaving of around 11% in the residential sector [VaasaETT, 2011]. Again, if necessary, assumptions should be tested through a sensitivity analysis.

3.2.8 Selection of control groups

In Smart Grid scenarios that involve testing new products and services, such as smart metering and time-varying tariffs, the goal is to evaluate their impacts on electricity consumers' behavior and in turn on customers' peak load curves and electricity bills.
The CBA should include estimation of these benefits and of the costs needed to realize the expected behavioral impacts. Baselines in such situations are preferably a 'control group' of comparable customers, randomly selected from the target population.
When establishing the target group(s) of customers, i.e. the group(s) that will reflect the impacts of the scenario, it is important to bear some risks in mind:

- **Self-selection**. Do not choose pilot customers with either a particularly high or low potential to reduce energy consumption. Use random sampling procedures. It is advisable to refuse customers that volunteer to participate in the pilot. It is

[1] Annex 7.10 to Commission Staff Working Document SEC(2011) 288 final — 'Impact Assessment': http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SEC:2011:0288:FIN:EN:PDF

also advisable to conduct statistical analysis on the customers who refuse to participate in the pilot to better understand this segment of consumers.

- **Exclusive focus on 'premium' groups**. Do not measure benefits only in groups with high access to information and high propensity to adopt new technologies as this will significantly bias the results. Define the segmentation of customers in such a way that it covers all types of consumers, independent of social level and education.
- **Ability to extrapolate results on a national level.** When working with sample groups, there is always the risk of the project not being able to identify the drivers that allow the extrapolation of the local results to a country level, assuring statistical validity. To mitigate this risk, use social-demographic data to compare customers across the country. This will enable the estimation of the impact at a national level.
- **Mismatch between segments and products & services.** The risk of the products and services offered not being compatible with certain customer segments can be mitigated by conducting initial socio-demographic analysis to identify which products and services are most likely to work best in which segments.

3.2.9 Implementation parameters

Smart metering architecture, design parameters, and technology can greatly affect the CBA outcome.

In defining the system architecture, particular attention should be devoted to ensuring the adoption of suitable measures in order to guarantee interoperability (e.g. open protocols and multiple vendors), as well as to the choice of the communication technology (e.g. PLC vs. GPRS). The latter can significantly affect the final cost-benefit outcome.

Other critical variables include: number and prices of smart meters, operational costs of smart meters (installation costs, manual reading costs in case of communication failure) and economic benefits (such as resource costs savings, loss reductions etc.).

In regards to the hardware costs, good practices for their estimation include a market consultation. The AMI hardware cost can vary significantly from country to country and according to the technology. In [EPRI 2011], the per-unit cost of AMI for residential meters in the US is estimated to be the equivalent of €52-104, while that of more sophisticated commercial and industrial meters is estimated to be €89-370[2]. In a recent study, [Faruqui et al 2010] stipulate that AMI investment costs in the EU can range from €70 for residential meters to €450 for industrial meters, assuming an approximate cost of €120 per household meter (and €450 per industrial meter) for their calculations. In the Commission for Energy Regulation's (CER) CBA for a national smart meter roll-out in Ireland, the cost for PLC-based meters is €75 and €105 for monophasic and polyphasic meters respectively [CER 2011].

In assessing the technology cost, it is also important to take into account the cost reduction associated with technology maturity, which is linked to the emergence of economies of scale and increased reliability of a new technology.

The installation cost of Smart Grid components (and the associated training costs of installation personnel) is another key variable to take into account. In the case of AMI, (urban) installation costs range from €48 in Ireland to €32 in Great Britain, from €64 in the Netherlands [CER 2011] to €16 in Portugal.

The selection of the communications technology (PLC, GPRS, 3G, G3, RFmesh, Wimax, etc.) is another critical element, as it has different implications on CAPEX (Capital Expenditures) and OPEX (Operational Expenditures) throughout the life of the meter. For example: PLC is more CAPEX intensive, whereas GPRS is OPEX intensive. Also, different communication technologies can allow different functionalities, and different functionalities will imply different costs in terms of initial investment and operational costs.

In this context, the communication success rate (percentage of successful remote communication data exchange from/to the smart meter) is another important variable to set. It is necessary to take into account the possibility that, due to technical errors,

[2] Assumption: 1 USD=0.74 EUR.

the communication of a certain percentage of total smart meters might fail at one point or another. This value will affect in particular the benefit resulting from '*Reduced meter reading cost'.*

3.2.10 Impact of the regulatory framework on set assumptions/parameters

It is also recommended that information is provided about the regulatory framework in the Member State where the roll-out is taking place (e.g. presence of a risk premium to Smart Grid investments over traditional investment, investment in meters included in Remunerated Asset Base), specifying the impact of regulation on the assumptions and on the benefit calculations of the CBA. In particular, it is important to highlight the specific role of actors in the electricity market and to show how this might affect the distribution of costs and benefits. For example: It makes a difference in the set-up of the CBA whether meters are owned by the households, by the grid company or by the energy supplier. It should be clearly spelled out how the specific market model impacts the amount and distribution of costs and benefits. It is also necessary to clarify the specific tariff structures (e.g. capacity based connection tariffs or consumption based tariff structures) that are in force and to outline how they affect costs and benefits calculations.

3.3 COST-BENEFIT ANALYSIS

In the following we will provide a short description of the seven steps to carry out the CBA. More details can be found in [EC, 2012b]).

Guideline 2 – Review and describe the technologies, elements and goals of the scenario (CBA step 1)

The first step is to provide a main summary and to describe the elements and goals of the project in the chosen scenario. The project within the chosen scenario should be clearly defined as a self-sufficient unit of analysis. This might involve providing (some of) the following information:

- √ the scale and dimension of the project (e.g. in terms of served consumers, energy consumption per year)
- √ the engineering features (e.g. adopted technologies and functionalities of main components)
- √ the local characteristics of the grid
- √ the relevant stakeholders (i.e. whose costs and benefits count?)
- √ a clear statement of the project's objective and its expected socio-economic impact

Guideline 3– Map assets into functionalities (CBA step 2)

The purpose of step 2 is to determine which Smart Grid functionalities are activated by the assets (e.g. smart meters, communication infrastructure etc.) deployed in the considered scenario. Consider each asset individually and contemplate how it could contribute to any of the functionalities. Different assets provide different types of functionalities that in turn enable benefits. If the assets deployed and/or functionalities enabled by the scenario are unclear, the analysis is likely to be incomplete.

To complete this step, consider the assets in the scenario. Assess each asset in turn and select from among the 33 functionalities [EC Task Force for Smart Grids, 2010a] those that are (potentially) activated by the assets (an example is reported in Box 1). The assets-functionalities matrix is reported in ANNEX VI.

We remark that the 33 Functionalities have been introduced for broader Smart Grid deployments. Therefore some of them do not apply for an SMD (e.g. grid reconfiguration, power flow analysis, voltage/current control).

Box 1 - Illustrative example of assets-functionalities mapping

FUNCTIONALITIES

ASSETS	Integrate users with new requirements				Enahancing efficiency in day-to-day grid operation						Ensuring network security, system control and quality of supply						Better planning of future network investment			Improving market functioning and customer service								More direct involvement of consumers in their energy usage					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
Smart Meter	•	•	•	•	•	•	•			•	•	•	•			•	•		•	•		•	•		•	•	•	•	•	•	•		•
HAN Module																						•			•			•		•	•		•
Meter Data Management (MDM)		•		•	•	•	•	•	•	•	•	•	•		•	•	•	•	•		•			•				•	•	•			•
Energy Data Management (EDM)							•		•											•	•			•									
DSO Webportal	•	•																		•	•	•	•	•	•			•	•	•	•	•	•
Supervision Module		•	•	•	•	•	•	•		•					•			•	•														
Meter Asset Management (MAM)								•										•											•				

Guideline 4 – Map functionalities into benefits (CBA step 3)

Consider each functionality individually and contemplate how it could contribute to any of the benefits listed in the first column of the functionalities-benefits matrix (see ANNEX VII). This analysis should continue until all applicable functionalities are considered (an example is reported in Box 2).

Box 2 - Illustrative example of functionalities-benefits mapping

FUNCTIONALITIES

BENEFITS

	Integrate users with new requirements				Enahancing efficiency in day-to-day grid operation						Ensuring network security, system control and quality of supply						Better planning of future network investment			Improving market functioning and customer service								More direct involvement of consumers in their energy usage					
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
Optimized Generator Operation																	•																
Deferred Generation Capacity Investments																									•					•			
Reduced Ancillary Service Cost			•			•				•																							
Reduced Congestion Cost																																	
Deferred Transmission Capacity Investments																									•								
Deferred Distribution Capacity Investments						•	•	•								•		•	•		•				•					•			
Reduced Equipment Failures						•	•	•										•	•														
Reduced Distrib. Equipment Mainten. Cost								•										•											•				
Reduced Distribution Operations Cost					•			•																					•				
Reduced Meter Reading Cost																												•	•				
Reduced Electricity Theft									•						•									•				•					
Reduced Electricity Losses			•			•	•	•	•	•		•	•				•		•	•	•			•						•			
Detection of anomalies on Contracted Power							•																										
Reduced Electriciy Cost								•				•										•			•			•	•				
Reduced Sustained Outages			•	•	•			•					•				•			•													
Reduced Major Outages					•									•																			
Reduced Restoration Cost					•	•	•																						•				
Reduced Momentary Outages					•	•	•																						•				
Reduced Sags and Swells						•	•																										
Reduced CO2 Emissions	•	•				•	•	•	•	•		•					•		•			•	•		•			•	•	•	•	•	
Reduced SOx, NOx, and PM- 10 Emissions	•	•				•	•	•	•	•		•					•		•			•	•		•			•	•	•	•	•	
Reduced Oil Usage	•	•				•	•																•					•	•				
Reduced Wide-scale Blackouts																																	

Guideline 5 – Establish the baseline (CBA step 4)

The objective of establishing the scenario baseline is to formally define the 'control state' that reflects the system condition which would have occurred had the scenario not taken place. This is the baseline situation to which all other scenarios of the analysis are compared. The CBA of any action/investment is based on the difference between the costs and benefits associated with the Business As Usual 'BaU' scenario and those associated with the implementation of the other scenario.

The CBA should refer to the useful life of the SMD investments, which refers to the period of time when the installed smart metering system is intended to perform reliably its designed functions.

Guideline 6 – Monetize the benefits and identify the beneficiaries (CBA step 5)

Identify, collect and report the data required for the quantification and monetization of the benefits (see [EC, 2012b] for more details). These data might be raw data, such as hourly load data, or already processed data, such as energy savings. Key assumptions and the level of estimation uncertainty should be clearly documented. Also, it is important to consider an extensive value chain and allocate benefits to different market actors.

The results of cost-benefit analyses for smart metering roll-outs across Member States ([CER 2011, Atkearney, 2010; PwC Österreich, 2010]) clearly indicate that the costs and benefits of smart metering are likely to vary across different stakeholder groups. In undertaking the cost-benefit analysis, we recommend that the perspective not be restricted to costs and benefits incurred by the player responsible of the smart metering roll-out (typically distribution system operators). The analysis should try to identify and capture costs and benefits as much as possible for other stakeholders as well, and also for society at large. The beneficiaries (consumers, system operators, society, retailers etc.) associated with each cost and benefit should be identified, if possible with a quantitative estimation of their corresponding share. This may provide a useful indication of how costs and benefits are distributed across the whole value chain.

In particular, we recommend performing this kind of analysis at least for the actor implementing the project (in order to evaluate the financial viability of the investment) and for consumers. Data required to perform this kind of analysis is typically a sub-set of the data required for the overall CBA.

Table 3 reports some suggested formulae (not exhaustive) for the monetization of possible benefits related to the smart metering roll-out. We further stress that some of these benefits might be fully reaped only when additional Smart Grid capabilities are implemented together with the smart metering infrastructure (e.g. reduction of outage times through advanced monitoring and real-time network information; reduced losses via voltage control). If these benefits are included in the cost-benefit analysis, it should be clearly mentioned which Smart Grid capabilities are envisioned together with the smart meter roll-out to achieve those benefits and their cost. More details can be found in [EC, 2012b].

Benefit	Sub-benefit	Monetization calculation
Reduction in meter reading and operations costs	Reduced meter operations costs	***Value (€) = [Estimated cost reductions with remote meter operations (€/year)- Estimated cost reductions with remote meter operations (€/year) * Communications failure rate (%/100)]** $_{\textit{Roll-out scenario}}$*
	Reduced meter reading costs	***Value (€) = [cost with local meter readings (€)]** $_{\textit{Baseline}}$ **– [Estimated cost of obtaining local 'disperse' meter readings (€)]** $_{\textit{Roll-out scenario}}$* ***Where*** ○ ***[cost with local meter readings (€)]** $_{\textit{Baseline}}$ **=# of clients in LV * Historical meter reading cost/client (€)*** ○ ***[Estimated cost of obtaining local 'disperse' meter readings (€)]** $_{\textit{Roll-out scenario}}$ **=[# of clients in LV *% of clients <u>not included</u> in the roll-out*Average disperse reading cost per client (€/client)]+ [# of clients in LV *% of clients <u>included</u> in the roll-out*Communications failure rate (%)*Average disperse reading cost per client (€/client)]***
	Reduced billing costs	***Value (€) = [# of clients in LV * Billing cost/client/year (€)]** $_{\textit{Baseline}}$ **— [# of clients in LV * Billing cost/client/year (€)]** $_{\textit{Roll-out scenario}}$*

	Reduced call centre/customer care costs	***Value (€) = [# of clients in LV * Customer care cost/client/year (€)]$_{Baseline}$ — [# of clients in LV * Customer care cost/client/year (€)]$_{Roll\text{-}out\ scenario}$***
Reduction in operational and maintenance costs	Reduced maintenance costs of assets	***Value (€) = [Direct costs relating to maintenance of assets(€/year)]$_{Baseline}$ — [Direct costs relating to maintenance of assets (€/year)] $_{Roll\text{-}out\ scenario}$***
	Reduced costs of equipment breakdowns	***Value (€) = [Cost of equipment breakdowns (€)]$_{Baseline}$ — [Cost of equipment breakdowns (€)] $_{Roll\text{-}out\ scenario}$***
Deferred/avoided distribution capacity investments	Deferred distribution capacity investments due to asset remuneration	***Value (€) = Annual investment to support growing capacity (€/year) * Time deferred (# of years) * Remuneration rate on investment (%/100)***
	Deferred distribution capacity investments due to asset amortization	***Value (€) = Annual investment to support growing capacity (€/year) * Time deferred (# of years) * # of years capacity asset amortization***
Deferred/avoided transmission capacity investments	Deferred transmission capacity investments due to asset remuneration	***Value (€) = Annual investment to support growing capacity (€/year) * Time deferred (# of years) * Remuneration rate on investment (%/100)***
	Deferred transmission capacity investments due to asset amortization	***Value (€) = Annual investment to support growing capacity (€/year) * Time deferred (# of years) * # of years capacity asset amortization***
Deferred/avoided generation capacity investments	Deferred generation investments for peak load plants	***Value (€) = Annual investment to support peak load generation (€/year) * Time deferred (# of years)***
	Deferred generation investments for spinning reserves	***Value (€) = Annual investment to support spinning reserve generation (€/year) * Time deferred (# of years)***
Reduction of technical losses of electricity	Reduced technical losses of electricity	***Value (€) = Reduced losses via energy efficiency (€/year) + Reduced losses via voltage control (€/year) + Reduced losses at transmission level (€/year)***
Electricity cost savings	Consumption reduction	***Value (€) = Energy rate (€/MWh) * Total energy consumption at LV (MWh) * Estimated % of consumption reduction with roll-out (%/100)***
	Peak load transfer	***Value (€) = Wholesale margin difference between peak and non-peak generation (€/MWh) * % Peak load transfer (%) * Total energy consumption at LV (MWh)***
Reduction of commercial losses	Reduced electricity theft	***Value (€) = % of clients with energy theft (%/100) * Estimated average price value of energy load not recorded/client (€) * Total number of clients LV (# of clients)***
	Recovered revenue relating to 'contracted power' fraud	***Value (€) = % of clients with 'contracted power fraud' (%/100) * Estimated price value of contracted power not paid/client (€) * Total number of clients LV (# of clients)***
	Recovered revenue relating to incremental 'contracted power'	***Value (€) = % of clients requesting incremental contracted power after smart metering system installation (%) * Average estimated value of recovered revenue due to incremental contracted power (€) * Total number of clients LV (# of clients)***

Reduction of outage times (thanks to advanced monitoring and real-time network information)	Value of service	*Value (€) = Total energy consumed MV[3]+LV (MWh)/ Minutes per year (#/year) * Average non-supplied minutes/year ((#/year) * Value of Lost Load (€/MWh) * % Decrease in outage time (%/100)*
	Recovered revenue due to reduced outages	*Value (€) = Annual revenue LV (€)/ Minutes per year (#/year) * Average non-supplied minutes/year (#/year) * % Decrease in outage time (%/100)*
	Reduced cost of client compensations	*Value (€) = Average annual client compensations (€/year) * % Reduction of client compensations*
Reduction of CO_2 emissions	Reduced CO_2 emissions due to reduced line losses	*Value (€) = [Line losses (MWh) * CO_2 content (tons/MWh) * Value of CO_2 (€/ton)]$_{Baseline}$ - [Line losses (MWh) * CO_2 content (tons/MWh) * Value of CO_2 (€/ton)]$_{Roll\text{-}out\ scenario}$*
	Reduced CO_2 emissions due to wider spread of low-carbon generation sources (as a consequence of the roll-out of smart metering)	*Value (€) = [CO_2 emissions (tons) * Value of CO_2 (€/ton)]$_{Baseline}$ — [CO_2 emissions (tons) * Value of CO_2 (€/ton)]$_{Roll\text{-}out\ scenario}$*
	Reduced CO_2 emissions due to truck rolls of field personnel	*Value (€) = Avoided # liters of fuel (#) * Cost per liter of fuel (€)*
	Reduced fuel usage due to truck rolls of field personnel	*Value (€) = Avoided # liters of fuel (#) * Cost per liter of fuel (€)*
Reduction of air pollution (Particulate Matters, NOx, SO2)	Reduced air pollutants emissions due to reduced line losses	**For each pollutant:** *Value (€) = [Line losses (MWh) * air pollutant content (unit/ MWh)* cost of air pollutant (€/unit)]$_{Baseline}$ - Line losses (MWh) * air pollutant content (unit/MWh)* cost of air pollutant (€/unit)]$_{Roll\text{-}out\ scenario}$*
	Reduced air pollutants emissions due to wider diffusion of low carbon generation sources (as a consequence of the roll-out of smart metering)	**For each pollutant:** *Value (€) = [air pollutant Emissions (unit) * cost of air pollutant(€/unit)]$_{Baseline}$ — [air pollutant Emissions (unit) * cost of air pollutant(€/unit)]$_{Roll\text{-}out\ scenario}$*
	Reduced air pollutants emissions due to reduced line losses	**For each pollutant:** *Value (€) = [Line losses (MWh) * air pollutant content (unit/ MWh)* cost of air pollutant (€/unit)]$_{Baseline}$ - Line losses (MWh) * air pollutant content (unit/MWh)* cost of air pollutant (€/unit)]$_{Roll\text{-}out\ scenario}$*

Table 3 – Some suggested formulae for the monetization of benefits

Some general recommendations are:

√ Benefits should represent those actually resulting from the scenario.

[3] Medium voltage

- √ Benefits should be significant (meaningful impact), relevant to the analysis and transparent in their quantification and monetization.
- √ Calculation of benefits should be transparent and clearly documented.
- √ The individual benefit and cost variables should be mutually exclusive. In other words, avoid including one type of benefit as part of another type of benefit.
- √ The level of uncertainty associated to the benefit estimation should be clearly stated and documented.
- √ The beneficiaries (consumers, system operators, society, retailers etc.) associated with each benefit should be identified, if possible with a quantitative estimation of the corresponding share. In particular, we recommend performing this kind of analysis at least for the actor(s) implementing the project (in order to evaluate the financial viability of the investment) and for the consumers. Alternatively, we recommend using the list of benefits and beneficiaries provided by [ERGEG 2011] and reported in ANNEX IV, to associate (qualitatively) benefits with beneficiaries along the smart metering system value chain.

Guideline 7 – Identify and quantify the costs (CBA step 6)

Some costs can be directly measured by the actor(s) carrying out the smart metering roll-out, while others are typically easy to estimate since their prices, or very good proxies, can be easily obtained in the market place. The costs should include capital, ongoing/operational, and transitional costs.

Collecting information on the roll-out's costs is necessary for determining its return on the investment, whether it is positive, and if so, when the scenario breaks even. Even though identifying these costs is not usually a difficult exercise, it does require meticulous itemization of all important costs. In general,

- √ cost data is a combination of estimated costs obtained through dialogue with suppliers and of data coming directly from the scenario and tracked by the actor(s) carrying out the smart metering roll-out;

- √ estimation of activity-based costs should be done with approved accounting procedures for handling capital costs, debit, depreciation, etc.;
- √ costs related to any additional Smart Grid capability that might be implemented together with the SMD should be separately highlighted.

Different categories of costs associated with smart metering deployment can be identified. Table 4 reports a representative but not exhaustive list of costs that need to be tracked.

General category	Type of cost to be tracked for roll-out and to be estimated for the baseline
CAPEX	Investment in the smart metering system
	Investment in IT
	Investment in communications
	Investment in in-home displays (if applicable)
	Generation
	Transmission
	Distribution
	Avoided investment in conventional meters (negative cost, to be added to the list of benefits)
OPEX	IT maintenance costs
	Network management and front-end costs
	Communication/data transfer costs (inc. GPRS, Radio Communications, etc)
	Scenario management costs
	Replacement/failure of smart metering systems (incremental)
	Revenue reductions (e.g. through more efficient consumption)
	Generation
	Distribution
	Transmission
	Meter reading
	Call centre/customer care
	Training costs (e.g. customer care personnel and installation personnel)
Reliability	Restoration costs
Environmental	Emission costs (CO_2 control equipment, operation and emission permits)
Energy security	Cost of fossil fuels consumed to generate power
	Cost of fossil fuels for transportation and operation
Other	Sunk costs of previously installed (traditional) meters

Table 4 – List of some of the costs to be tracked

Some recommendations:

- √ Costs should represent those actually resulting from the roll-out scenario.
- √ Calculation of costs should be transparent and clearly documented.
- √ Stranded costs (e.g. replacement of traditional meters before their expected lifetime) should be highlighted and reported as a separate line item.
- √ The level of uncertainty associated with the cost estimation should be clearly stated and documented.
- √ The stakeholders (consumers, system operators, society, retailers etc.) bearing the different costs should be identified, if possible with a quantitative estimation of the corresponding share.
- √ Costs could also include investments in pilot projects that prove necessary to substantiate the cost-benefit estimates before the actual roll-out.
- √ The avoided investment costs in conventional meters is used as “negative” costs (and thus as a benefit), that needs to be properly discounted (according to the schedule of installation of conventional meters that would have taken place without the smart metering roll-out) and added to the benefits calculated in step 5.
- √ Avoided investments to support future Smart Grid implementation should be properly discounted and added to the benefits calculated in step 5.
- √ The choice of the amortization rate depends on the technology ageing speed and on the assumptions on the market conditions. If the market imposes a high innovation turnover on some assets (e.g. IT) or if uncertainty exists, the amortization rate has to be set conservatively high.

Box 5 - Example:
Identification and Quantification of costs

For the estimation of relevant costs a market consultation can be done. The results provided reasonable estimates of costs of action for a smart metering roll-out scenario, such as the costs of smart meters, telecommunication network, etc. Examples include:

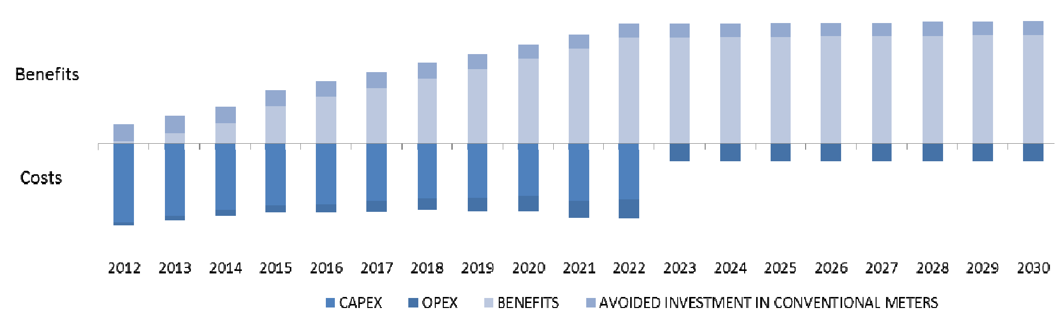
Cost of Smart Meter	€/unit
Installation Cost of Smart Meter	€/unit
Cost of data transfer	€/year
Customer care program	€/customer

Guideline 8 – Compare costs and benefits (CBA step 7)

Once costs and benefits have been estimated, there are several ways to compare them in order to evaluate the cost-effectiveness of the scenario. The most common methods include Annual Comparison, Cumulative Comparison, Net Present Value and Cost-Benefit Ratio (see [EPRI 2010, EC 2012b] for more details).

Box 6 - Example:
Comparison between costs and benefits

Figure below shows the *annual comparison* method, comparing on an annual basis costs (CAPEX+OPEX) and benefits (including avoided investment in conventional meters).



3.4 SENSITIVITY ANALYSIS

Guideline 9 – Perform a sensitivity analysis

Sensitivity analysis indicates to what extent the profitability of a scenario is affected by variations in key quantifiable variables. This analysis is most commonly performed by calculating changes in the internal rate of return (IRR) or net present value (NPV).

Firstly, different economic, demographic, geographic, commercial and power industry-specific factors play a huge role in determining the importance of benefits for different Member States/regions. Other benefits that are likely to vary significantly across countries include *Reduced Electricity Cost and Reduced Electricity Theft*, as they all depend strongly on country-specific variables.

Secondly, a CBA is strongly based on forecasts and estimates of quantifiable variables, such as demand (e.g. electricity demand growth rate), costs (e.g. CAPEX, OPEX) and benefits (or cost reductions). The values of these indicators are those considered to be the most probable forecasts. However, these forecasts often cover a long period of time and may thus differ significantly from values actually realized. Future developments depend on a great number of factors, which is why it is essential to take into consideration likely changes in key variables and the profitability of a scenario, i.e. to perform a sensitivity analysis.

A sensitivity analysis can consist of varying major benefits and costs one at a time or in combination. This technique will help project coordinators assess whether and how scenario decisions could be affected by such changes, and it will help them identify actions that could mitigate possible adverse effects on the scenario. Good candidates for inclusion are variables with a wide range of potential values and/or which are more subjective in nature (e.g., consumer participation, estimation of peak transfer).

The outcome of the sensitivity analysis should be to identify the range of parameter values enabling a positive outcome of the CBA (e.g. benefit/cost ratio greater than one).

A flow chart of the application of the sensitivity analysis loop (in red) is shown in Figure 6. The sensitivity analysis loop is represented with red flows in the diagram. For each scenario, the different options (set-up of variables/parameters/technical options as illustrated in guideline 1) are set in the “Define initial conditions” step. Typically, for any given scenario, changes in the initial conditions do not affect which benefits are activated (steps 1, 2 and 3 of the CBA). Rather, they affect the amount of the benefits. If this is not the case, then the first three steps of the CBA should also be considered in the sensitivity analysis loop of Figure 6.

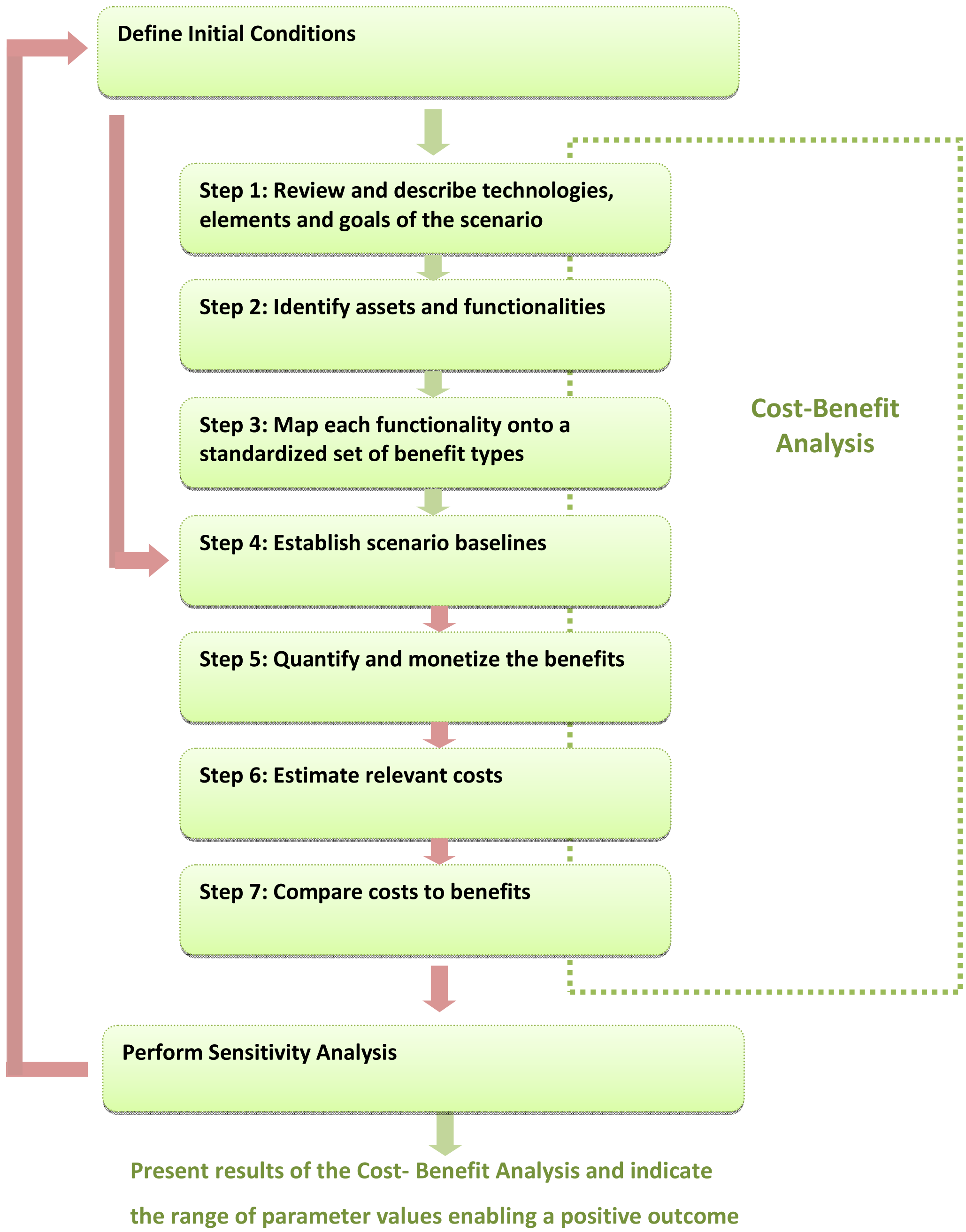
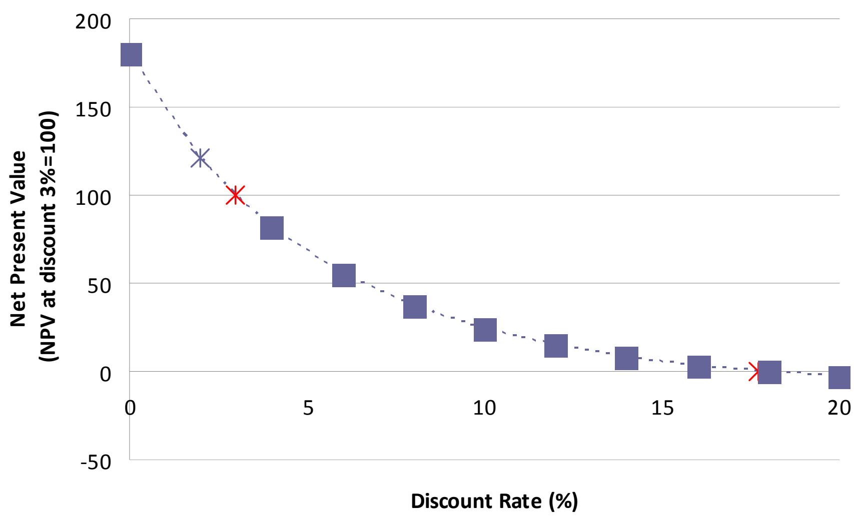


Figure 6 – Flowchart representing the sensitivity analysis loop

Box 7 - Example:
Sensitivity Analysis on the discount rate

All cost-benefit analyses should be tested for sensitivity to the discount rate [UNEP 2009]. This analysis can be undertaken like in the figure below, which shows the relationship between the discount rate and the net present value.



3.5 QUALITATIVE IMPACT ANALYSIS – NON MONETARY APPRAISAL

Guideline 10 –Assess deployment merit (performance assessment), externalities and social impact

A qualitative analysis (non monetary) appraisal of scenario impacts not captured in the CBA should complement the result of the CBA. Suitable weighting factors to combine the quantitative and qualitative analysis should then be advised by the Member States. We recommend considering the:

√ deployment merit of the scenario (performance assessment) in terms of expected outcomes and policy objectives. In section 3.5.1 we provide a structured framework based on key performance indicators.

√ identification and appraisal of non-monetary impacts on the electricity system (e.g. enabling new services and applications) and on society at large (e.g. social acceptance, job creation, consumer inclusion).These externalities should be expressed as much as possible in physical units, to provide a more objective basis for the project appraisal. Where this is not feasible, a detailed description of the expected impacts should be presented. In section 3.5.2 we provide a (non-exhaustive) list of possible externalities.

The outcome of the overall qualitative analysis of a given scenario should therefore include (i) KPI-based scores of the scenario merits on different objectives and (ii) qualitative appraisal of foreseen externalities, with particular reference to social impact. The final outcome should be a vector like the one reported din Figure 7.

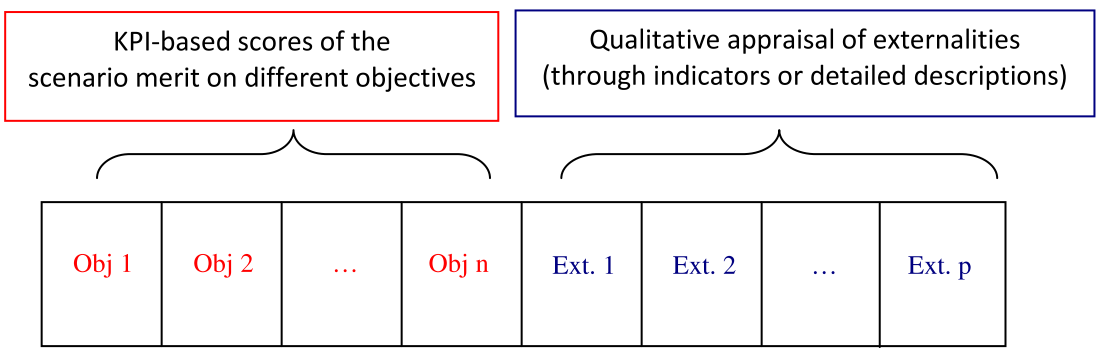


Figure 7 – Outcome vector of the qualitative impact analysis with respect to policy objectives (Obj) and externalities (Ext)

Once the outcome vector is built, a technique should be devised to aggregate information, and expert judgment needs to be used to assess the overall impact. The outcome of the analysis should then be integrated in the economic analysis through suitable weights to make a comprehensive appraisal of the scenario.
We stress that the analysis of non-monetary impacts need to be treated very cautiously, especially when the analysis does not rely on quantitative indicators but on vague and subjective descriptive appraisals.

3.5.1 Merit deployment analysis – KPI-based assessment of impacts

The goal of this section is to assess the SMD merit with reference to key policy objectives that are driving the smart metering roll-out. We recommend carrying out this assessment via the key performance indicators (see ANNEX II) proposed by [ERGEG 2010; EC Task Force for Smart Grids, 2010c]).

To this end, it is necessary to fill in the merit deployment matrix proposed by [EC Task Force for Smart Grids, 2010c] (see ANNEX VIII). By summing up the matrix cells along the rows, it is possible to derive the outcome vector composed of the scenario's score for each of the "benefits"[4] listed in the rows of the merit deployment matrix (see ANNEX II and ANNEX VIII).

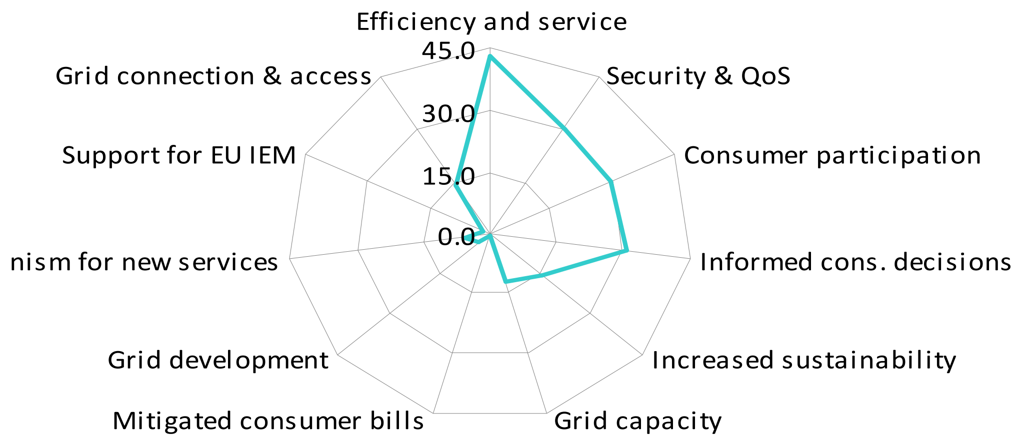
For the sake of clarity, the outcome vector can then be mapped into spider diagrams (see Box 8 for an example). The vector elements, representing the scenario's scores on the corresponding benefits/objectives, might then be weighted according to the relative importance given to them.

All choices and assumptions made (especially in filling in the deployment merit matrix) should be clearly documented and explained. We recommend that, at the national level, a single institutional body (e.g. National Regulatory Authorities) be in charge of monitoring this exercise.

[4] These benefits are different from the ones used in the CBA, which are concrete final benefits that can be expressed in monetary terms. These benefits represent the expected outcomes of the Smart Grid implementation and are tightly intertwined with the key policy objectives that have triggered the Smart Grid and the smart metering propositions.

Box 8 - Example:
Merit deployment

The merit deployment matrix ([EC Task Force for Smart Grids, 2010c; EC2012b]; see also ANNEX VIII) can provide a qualitative indication of the impact of Smart Grid projects (including SMD) to key policy objectives, measured through the benefits and key performance indicators reported in ANNEX II. Figure below shows an example of a spider diagram derived from the merit deployment matrix: the larger the area in the graph, the higher the impact of the project.



3.5.2 Qualitative appraisal of externalities

In this section we will consider all costs and benefits that spill over from the SMD into society and that cannot be monetized and included in the economic analysis (externalities). In particular, we are presenting two different perspectives to address SMD externalities: (i) identification of future new services and applications enabled by the SMD, (ii) identification of expected social impacts.

We recommend defining an indicator for each externality as much as possible, in order to make the assessment as objective and rigorous as possible. The choice and the calculation of each indicator should be transparently illustrated and justified. Where the calculation of an indicator (expressed in physical units) is not feasible, a detailed description of the estimated impacts of the SMD should be provided to give as many elements as possible for the appraisal. Another option is using a “benefit transfer” approach, i.e. using values previously estimated in other projects/scenarios with similar conditions as proxy for the same benefits in the scenario under analysis.

I. Identification of future new services and applications enabled by the smart metering infrastructure

SMD coordinators should identify and qualitatively discuss the future new services and applications that might be enabled by the SMD and the benefits that may ensue (an example is reported in Box 9). Typically, some of these additional features are already partially quantified in the benefits of Table 3, like “Energy Efficiency” benefits, “reduced electricity costs”, “peak load transfer”, “reduce CO_2 emissions”. It is also worthwhile specifying the additional Smart Grid capabilities that are necessary to actually reap the services and applications enabled by the smart metering infrastructure.

Box 9 - Example of new services and additional benefits:

	TODAY	TOMORROW
Billing	Based on quarterly manual meter readings combined with energy estimation	Based on remote reading and “real–time” consumption
Access to information	Available by internet only and based on the last meter reading	Increased flexibility through an access to the energy profile using internet displays, PDS, Smartphone etc.
Services	Contract changes typically need to be scheduled and performed on location.	Contract changes and other commercial operations can be performed remotely.
Tariffs	Fewer price plans and tariffs	Increased flexibility in pricing and tariffs, fitted to the client profile
Value added services	Limited value added services and client participation	Capacity to inform consumers through different channels including SMS, email, web portal etc.

II. Qualitative and/or quantitative estimation of social impact of the SMD

The qualitative appraisal should include an identification and assessment of the social impacts of the SMD. Some of the areas of focus and of the qualitative discussion should include the following:

√ **Jobs**

In this area, one important challenge is to evaluate the impact on jobs along the whole value chain and to identify the segments where jobs might be lost or gained. The analysis might include an estimation of the number of created/lost jobs in the supply and operation value chain (see Box 10).

√ **Safety**

This analysis might take into account new possible sources of hazard or of reduction of hazard exposure (e.g. fewer field workers due to remote reading through smart metering).

It is important that companies take the responsibility to ensure that both direct employees and workers from third-parties have the adequate training and skills. Third parties should be appropriately vetted for competence and compliance, including health and safety standards

If feasible, a quantitative indicator might be an estimation of the reduction in the risk of death or serious injuries.

√ **Environmental impact**

This analysis might consider the impact on the environment in terms of noise (noise reduction/increase) or of landscape change. If numerical indicators cannot be calculated (e.g. decibel), the scenario appraisal might try to include a detailed description of the expected (positive or negative) impacts.

If a monetization of the reduced CO_2 and the air pollutant emission has not been carried out in the economic appraisal (i.e. in the CBA), these impacts should be taken into account here, preferably expressed in physical units (e.g. ton).

√ **Social acceptance**

In many instances, social acceptance is critical for the successful implementation of SMDs. Social resistance might arise due to concerns about transparency, fair benefit sharing or environmental impact. The consequences of the SMD on this subject should be assessed and mitigation strategies proposed.

√ **Time lost/saved by consumers**

The analysis might try to capture and quantify (e.g. in terms of minutes) the impact of the implementation of smart metering technologies on time saved/lost by consumers.

For example: In a smart metering installation project, consumers might save complaint time as bills are more accurate and transparent or they might save time having their tariff plan changed as this can be done remotely.

√ **Ageing work force – gap in skills and personnel**

This analysis might address the impact of the SMD in terms of it reducing the gap in skills and personnel due to "Graying workforce”, i.e. shortages of qualified technical personnel due to retirement of skilled technicians. It might also analyze the impacts in terms of it creating new skills and boosting know-how and competitiveness.

√ **Privacy and Security**

This analysis might address the foreseeable activities in developing measures to ensure data privacy and cyber-security. It might qualitatively include the expected additional costs for implementing preventive measures.

Box 10 - Example:

Job creation:

- Number of direct utility jobs created by smart metering roll-out because of the need for new skills.
- Number of low skilled utility positions (e.g. meter reading) transitioned to other roles.
- Other categories that might be impacted include direct and indirect utility suppliers (supply chain providers like manufacturers, communication providers, integrators etc.), aggregators entering the market to provide energy services, new industry players (renewable energy suppliers, electric vehicle manufacturers and suppliers etc.).

REFERENCES

Atkearney (2010). Assessment of Smart Metering Models: The Case of Hungary. Report available from http://www.esmap.org/esmap/sites/esmap.org/files/P110874_Hungary_Assessment%20of%20Smart%20Metering%20Models_Dobozi.pdf

CER (Commission for Energy Regulation), 2011. Cost-Benefit Analysis (CBA) for a National Electricity Smart Metering Rollout in Ireland. Information Paper. Dublin: CER. Ref: CER11080c.

EPRI (Electric Power Research Institute) (Faruqui, A., Hledik, R.), 2010. "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Scenarios", Palo Alto, CA: EPRI. 1020342.

EPRI (Electric Power Research Institute), 2011. "Estimating the Costs and Benefits of the Smart Grid", available from http://ipu.msu.edu/programs/MIGrid2011/presentations/pdfs/Reference%20Material%20-%20Estimating%20the%20Costs%20and%20Benefits%20of%20the%20Smart%20Grid.pdf

ERGEG (European Regulators Group for Electricity and Gas), 2010. "Position Paper on Smart Grids. An ERGEG Conclusions Paper", 10 June 2010, available from http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/2010/E10-EQS-38-05_SmartGrids_Conclusions_10-Jun-2010_Corrigendum.pdf

ERGEG (European Regulators Group for Electricity and Gas), 2011. "Final Guidelines of Good Practice on Regulatory Aspects of Smart Metering for Electricity and Gas, An ERGEG report", available from http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab2/E10-RMF-29-05_GGP_SM_8-Feb-2011.pdf

European Commission, DG Regional Policy., 2008. "Guide to cost-benefit analysis of investment projects",– available from http://ec.europa.eu/regional_policy/sources/docgener/guides/cost/guide2008_en.pdf

European Commission, 2009. "Commission Impact assessment guidelines", available from http://ec.europa.eu/governance/impact/commission_guidelines/commission_guidelines_en.htm

European Commission Task Force for Smart Grids, 2010. "Expert Group 1: Functionalities of smart grid and smart meters", available from http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/expert_group1.pdf

European Commission Task Force for Smart Grids, 2010. “Expert Group 2: Regulatory Recommendations For Data Safety, Data Handling And Data Protection”, available from http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/expert_group2.pdf

European Commission Task Force for Smart Grids, 2010. “Expert Group 3: Roles and responsibilities”, available from http://ec.europa.eu/energy/gas_electricity/smartgrids/doc/expert_group3.pdf

European Commission, 2010. “How to develop a sustainable energy action plan“, Guidebook - The Covenant of Mayors, available from http://www.eumayors.eu/IMG/pdf/seap_guidelines_en.pdf

European Commission, 2011. “Smart Grids: From Innovation to Deployment”, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, available from: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0202:FIN:EN:PDF

European Commission, 2011. “Smart Grid projects in Europe: lessons learned and current developments”, Reference Report - Joint Research Centre Institute for Energy, available from http://ses.jrc.ec.europa.eu/

European Commission, 2011. “A joint contribution of DG ENER and DG INFSO towards the Digital Agenda, Action 73: Set of common functional requirements of the SMART METER”, joint DG ENER-DG INFSO study, available from http://ec.europa.eu/energy/energy2020/smart_grid/index_en.htm

European Commission, 2012. “Commission Recommendation on preparations for the roll-out of smart metering systems:, available from http://ec.europa.eu/energy/gas_electricity/smartgrids/smartgrids_en.htm

European Commission, 2012. “Guidelines for conducting cost-benefit analysis of Smart Grid projects”, Reference Report - Joint Research Centre, Institute for Energy and Transport, available from http://ses.jrc.ec.europa.eu/

European Union, 2009. Directive 2009/72/EC 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC, available from http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:32009L0072:EN:NOT

Faruqui, A., Harris, D. Hledik, R., 2010. “Unlocking the €53 billion savings from smart meters in the EU: How increasing the adoption of dynamic tariffs could make or break the EU’s smart grid investment”. Energy Policy, 38(10):382-395.

KEMA, 2010. “Smart meters in the Netherlands; revised financial analysis and policy advice”. KEMA report for the Dutch Ministry of Economic Affairs.

PwC Oesterreich, 2010. Studie zur Analyse der Kosten-Nutzen einer oesterreichweiten Einfuehrung von Smart Metering. PricewaterhouseCoopers. Available at www.pwc.at. Accessed in October 2011.

VaasaETT, 2011. “Empower demand”, VaasaETT report, available from http://www.esmig.eu/press/filestor/empower-demand-report.pdf

ANNEX I A GUIDE TO THE CALCULATION OF BENEFITS

This chapter provides a description of the benefit calculation formulas that have been introduced in table 3. Benefits should be calculated for each year of the time horizon of the analysis.

a. Reduction of meter reading and operations costs

In order to determine the value of this class of benefits, one possibility is to take into account historical costs with local meter readings (baseline scenario) and the projected costs with remote meter readings (project scenario).

Reduced meter operations cost:

Value (€) = [Estimated cost reductions with remote meter operations (€/year)] $_{roll\text{-}out\ scenario}$ ***- [Estimated cost reductions with remote meter operations (€/year) * Communications failure rate (%/100)]*** $_{roll\text{-}out\ scenario}$

The estimated cost reduction refers to meter operations that can now be performed remotely with a new smart metering infrastructure, such as change in contracted power, change of tariff plan, connection/disconnection etc. For the estimation of meter operations costs, one should take into account situations with communications failure and meter operations that will require local meter operations, such as in the case of breakdown or malfunction, meter replacement or installation of new homes (need to estimate a communication failure rate).

Reduced meter reading cost:

Value (€) = [cost with local meter readings (€)] $_{Baseline}$ ***– [Estimated cost of obtaining local 'disperse' meter readings (€)]*** $_{roll\text{-}out\ scenario}$

Where

[cost with local meter readings (€)] $_{Baseline}$ ***=# of clients in LV * Historical meter reading cost/client/year (€)***

[Estimated cost of obtaining local 'disperse' meter readings (€)] $_{roll\text{-}out\ scenario}$ ***=[# of clients in LV (# clients) * % of clients <u>not included</u> in the roll-out (%)*Average disperse reading cost***

per client (€/# clients)]+ [# of clients in LV (# clients) *% of clients included in the roll-out(%)*Communications failure rate (%)*Average disperse reading cost per client (€/# clients)]

Once remote meter reading is enabled through a smart metering infrastructure, a percentage of clients might still be unable to obtain remote reading. In the above formula we have considered two categories of clients requiring local meter reading services: i. Clients not included in the roll-out, ii. Clients included in the roll-out but experiencing communications failure of the remote reading.

The average extra cost to render local, geographically dispersed meter reading services to clients without smart meters or communication (e.g. expressed in €/client) needs to be estimated.

Reduced billing costs:

Value (€) = [# of clients in LV * Historical Billing cost/client/year (€)]$_{Baseline}$ – [# of clients in LV * Billing cost/client (€)]$_{roll\text{-}out\ scenario}$

This benefit refers to the (potential) cost reduction of billing operations by utilities/retailers due to more accurate consumption measurements. This benefit refers to the costs associated to billing operations, not to the actual billing amount paid by consumers.

Reduced call centre/customer care costs:

Value (€) = [# of clients in LV * Historical Customer care cost/client/year (€)]$_{Baseline}$ – [# of clients in LV * customer care cost/client/year (€)]$_{roll\text{-}out\ scenario}$

The estimated cost reduction refers to a reduction of customer claims to call centers on billing based on inaccurate meter reading. On the other hand, it is worth stressing that a higher number of customer inquiries about the new functionalities enabled by Smart Grid solutions (e.g. demand response, dynamic tariffs) might take place and negatively impact this benefit.

b. Reduced operations and maintenance cost

To calculate these benefits, the scenario should track the distribution operational and maintenance cost before and after the roll-out takes place. These benefits will typically consist of different components, like reduced maintenance costs, reduced rate of breakdowns etc. The benefits refer to the cost reduction which is due to monitoring and real-time network information, quicker detection of anomalies and reduced amount of time between a breakdown and the restoring of the supply. The following formulae are proposed for the calculation of their monetary impact:

Reduced maintenance costs of assets

Value (€) = [Direct costs relating to maintenance of assets(€)]$_{Baseline}$ – [Direct costs relating to maintenance of assets (€)] $_{roll\text{-}out\ scenario}$

Through remote control and monitoring of asset conditions and utilization (e.g. secondary substations LV), site visits could be avoided.

Reduced cost of equipment breakdowns

Value (€) = [Cost of equipment breakdowns (€/year)]$_{Baseline}$ – [Cost of equipment breakdowns (€/year)] $_{roll\text{-}out\ scenario}$

With a better knowledge of power flow and distributions of charge in the grid, less equipment (e.g. transformers) is likely to break down due to overcharge or maintenance failures. The benefit value can be estimated by considering the expected reduction in the number of equipment requiring replacement and the average cost of the equipment.

c. Deferred distribution capacity investments

The assumption underlying the monetization of this benefit is that the implementation of smart metering systems might allow reducing consumption and peak load (or at least a reduction in their growth rate in cases where there are underlying industrial, economic or social reasons for growth in electricity demand). Taken cumulatively, these two effects would lead to a reduction of maximum installed capacity required and consequently to a deferral of investments. However it must be borne in mind that unless the two effects are entirely discretely measured, the savings calculated may not necessarily be treated as cumulative benefits.

Monetization of these benefits across a system can only be indicative and the more specific the deferral (pertaining to several specific networks affected by a Smart Grid project), the more accurate the projected savings.

The simplest monetization formulae consider the impact on the amount of distribution capacity investments of asset remuneration on the one hand and of asset amortization on the other hand:

Deferred distribution capacity investments due to asset remuneration:

Value (€) = Annual DSO investment to support growing capacity (€/year) * Time deferred (# of years) * Remuneration rate on investment (%/100)

The current remuneration rate of distribution assets set by the regulator should be considered. The calculated value represents an avoided cost for the electricity system, with positive impact on tariffs.

Deferred distribution capacity investments due to asset amortization:

Value (€) = Annual distribution investment to support growing capacity (€/year) * Time deferred (# of years) * # of years capacity asset amortization

This calculation takes into consideration the deferral of the amortizations of the extra capacity assets that will not be installed; the rate is assumed to be 1/x per year (i.e. x years capacity asset amortization).

A more complex but potentially more accurate calculation method is the following:

First of all, it is necessary to estimate the incremental cost per MW of peak demand [€M/ΔMW]. This can be done considering the planned reinforcement projects to meet growing peak demand. These are based on measured peak demand (network specific) and projected growth rates determined on the basis of historical growth, economic, social and industrial factors.

Then we observe that peak reduction can be mainly obtained through two different means: consumption reduction and peak load shifting.

Then it is necessary to distinguish the consumers whose consumption level can be affected by the SMD. For example, we can assume that consumption reduction (e.g. 1%) should be applied only to the quota of peak demand due to domestic and small commercial loadings.

Separately, the potential for deferred cost of capacity (due to peak load shifting) needs to be calculated. This calculation should consider only those networks where the peak corresponds with the general peak (e.g. 6pm) when the potential for peak load shifting is higher.

The calculated savings need then to be divided by the number of years for which these reinforcement projects are planned and properly discounted. Possible monetization formulae are the following:

Deferred distribution capacity investments due to consumption reduction:

Value (€) = Peak demand reduction due to energy savings [MW]* Incremental cost per MW of peak demand [€M/ΔMW]

Where:

Peak demand reduction due to energy savings [MW] = % demand reduction * peak demand * % contribution of domestic and commercial load (or whatever load-type is influenced by the project in question)

Deferred distribution capacity investments due to peak load shift:

Value (€) = Peak demand reduction due to peak load shift [MW]* *% of networks where the peak corresponds with general peak *Incremental cost per MW of peak demand [€M/ΔMW]

d. Deferred transmission capacity investments

For the calculation of this benefit, similar considerations made at the distribution level apply (see previous item). Similar monetization formulae can be used.

e. Deferred generation capacity investments

For the calculation of this benefit, we suggest considering the impact on the amount of generation capacity investments of peak load plants on the one hand and of spinning reserves on the other hand.

The underlying assumption concerning the monetization of this benefit is that the Roll-out scenario will potentially allow reducing consumption and peak load and will provide demand side management tools to cope with supply variability. Taken cumulatively, these effects would lead to a reduction of maximum installed capacity and consequently to a deferral of investments.

Deferred generation investments for peak load plants:

Value (€) = Annual investment to support peak load generation (€/year) * Time deferred (# of years)

This takes into account the price of the marginal unit at peak and assumes that generation deferral is based on reducing peak demand.

Deferred generation investments for spinning reserves

Value (€) = Annual investment to support spinning reserve generation (€/year) * Time deferred (# of years)

f. Reduced electricity technical losses

As mentioned in the EPRI methodology [EPRI, 2010], several functions can contribute to loss reductions, and scenarios that demonstrate more than one of them at once will see compounded effects. The total benefit of reduced power losses comprises different sub-categories of benefits. They are related to i) energy efficiency (consumption reduction and peak load transfer at the distribution level, ii) improved balancing between phases, iii) increased distributed (micro-generation); iv) voltage control and v) consumption reduction at the transmission level.

One way of estimating technical loss reductions is the use of simulators. Another possibility to determine loss reductions, e.g. on a distribution feeder, would be to measure and compare hourly load and voltage data from smart meters as well as hourly load and voltage data from the head end of the feeder at the substation [EPRI 2011].

Reduced electricity technical losses:

Value (€) = Reduced losses via energy efficiency (€) + Reduced losses via voltage control (€) + Reduced losses at transmission level (€)

As an example, in this formula we include the estimated loss reductions via energy efficiency and via voltage control at distribution level and the estimated loss reductions at transmission level.

g. Electricity cost savings

For the calculation of this benefit, the impact of consumption reduction and peak load transfer on electricity cost savings have been considered. The following formulae are suggested for the calculation of the monetary impact of this benefit:

Consumption reduction:

Value (€) = Energy Rate (€/MWh) * Total energy consumption at LV (MWh) * Estimated % of consumption reduction with Roll-out scenario (%/100)

In ex ante calculations, a confident estimate of consumption reduction for domestic clients is difficult. Assumptions on consumption reduction can be done by analyzing international benchmarks and recent studies. They show that smart metering infrastructure might contribute to a consumption reduction of between 2% and 10%, depending on installed tools to trigger demand response and energy efficiency (e.g. in-home displays and dynamic tariffs, alerts, web-portals etc.).

Peak Load Transfer:

Value (€) = Wholesale margin difference between peak and non-peak generation (€/MWh) * % Peak load transfer (%/100) * Total energy consumption at LV (MWh)

The introduction of new tariff plans and detailed real-time information about consumption is expected to incentivize clients to shift part of their consumption to off-peak periods. The percentage of peak load transfer needs to be estimated. One way of monetizing this benefit is to use the price difference of the electricity wholesale margin between peak and off-peak periods (€/MWh).

h. Reduction of commercial losses

To calculate this benefit, the scenario should track commercial losses incurred before and after the scenario is put in place. We recommend taking into consideration at least the following two factors: *increased fraud detection relating to 'contracted power'* and *increased fraud detection relating to 'electricity theft'*. The following three formulae are proposed for the calculation of the monetary impact of this benefit:

Reduced electricity theft:

Value (€) = % of clients with energy theft (%/100) * Estimated average price value of energy load not recorded/client (€) * Total number of clients LV (# of clients)

Recovered revenue relating to 'contracted power' fraud:

Value (€) = % of clients with 'contracted power fraud' (%/100) * Estimated price value of contracted power not paid/client (€) * Total number of clients LV (# of clients)

Please note that this benefit is applicable only in those countries where contracted power is present.

Recovered revenue relating to incremental 'contracted power':

Value (€) = % of clients requesting incremental contracted power after smart metering system installation (%/100) * Average estimated value of recovered revenue due to incremental contracted power (€) * Total number of clients LV (# of clients)

After the installation of a smart metering system, it might emerge that in some cases clients were consuming more electricity than the amount contracted. As a consequence, an increase in 'contracted power' might be observed and extra monetary benefit might result for a DSO due to this correction of transactions.

Please note that this benefit is applicable only in those countries where contracted power is present.

i. Reduced outage times

Customer outage time can typically be measured by smart metering or outage management systems. This data can then be compared with average hourly loads to estimate the load that was not served during the outage. The value of the decreased load not served as a result of a particular asset and its functions must be attributed to that asset's contribution to the reduction in outage duration.

Reduced outage time can be achieved through monitoring and real-time network information, quicker detection of anomalies, remote management and automatic network reconfiguration. Since the % decrease in outage time varies across endpoints depending on the infrastructure installed, the value of service needs to be calculated separately for different installed assets (e.g. smart meters, distribution transformer controllers).

We suggest the following three formulae to calculate the monetary impact of this benefit:

Value of service:

Value (€) = Total energy consumed MV+LV (MWh)/ Minutes per year (#/year) * Average non-supplied minutes/year ((#/year) * Value of lost load (€/kWh) * % Decrease in outage time (%)

For the calculation of this value, it is necessary to adopt an index to measure technical service quality (e.g. Interruption Time Equivalent to Installed Capacity-TIEPI) and use a target in a BaU scenario (e.g. 100 minutes/year) as a reference. The value of lost load, which is typically set as a reference by national regulators, represents an estimated cost for the economy per kWh of electricity not supplied.

Note: When estimating the load not served (average non-supplied minutes), it is important to bear in mind the potential impact of load control and the energy efficiency on load not served. The average number of non-supplied minutes could decrease after the implementation of the scenario, e.g. as a result of customers using less electricity, without any actual improvement in reliability, i.e. outage duration.

Recovered revenue due to reduced outages:

Value (€) = Annual supplier revenue LV (€)/ Minutes per year (#/year) * Average non-supplied minutes/year (#/year) * % Decrease in outage time (%/100)

While the value of service benefit is a benefit associated with society at large, as it measures the cost of outages for the economy, this benefit refers to increased supplier's revenue due to a reduction in outage time.

Reduced cost of client compensations:

Value (€) = Average annual client compensations (€) * % Reduction of client compensations

This benefit refers to a reduction of client compensations relating to losses or injuries incurred by power outages.

j. Reduced CO_2 emissions and reduced fossil fuel usage

CO2 reduction can be achieved through different means, such as the incorporation of additional renewable sources or increased energy efficiency through the implementation of the roll-out scenarios. These values are, however, complex to calculate and should be evaluated on a case by case basis.

Another possible source of CO2 emissions is related to the reduction of the total mileage of DSOs' operational fleet and the consequent savings on liters of fuels and CO2 emissions due to remote meter readings and remote network operations.

In cases where the analysis permits the calculation of costs and benefits of resulting changes to carbon emissions, it is recommended that the analysis considers the carbon prices projected both in the Commission reference and decarbonisation scenarios[5].

Benefit of reduced CO_2 emissions due to reduced line losses:

Value (€) = [Line losses (MWH) * CO2 content (tons/MWH) * Value of CO2 (€/ton)]$_{Baseline}$ - [Line losses (MWH) * CO2 content (tons/MWH) * Value of CO2 (€/ton)] $_{roll\text{-}out\ scenario}$

This calculation monetizes the reduced CO2 emissions due to reduced line losses. If feasible, the estimation of this benefit should be integrated with a clear and transparent explanation of the value chosen for the CO2 content of the electricity produced (tons/MWH). In the definition of this value, the generation sources that are affected by the reduction of line losses should typically be taken into account.

Reduced CO2 emissions due to wider diffusion of low carbon generation sources (enabled by the SMD)

Value (€) = [CO2 Emissions (tons) * Value of CO2 (€/ton)] $_{Baseline}$ - [CO2 Emissions (tons) * Value of CO2 (€/ton)] $_{roll\text{-}out\ scenario}$

This benefit captures the emission reductions due to a wider diffusion of renewable energy sources and distributed generation. This benefit is extremely challenging to capture. Its estimation should be integrated with a clear and transparent explanation of the link between the SMD and the wider diffusion of low carbon generation sources.

Benefit of reduced CO2 emissions due to reduced fleet mileage of field personnel (e.g. truck rolls; meter reading operators):

Value (€) = Avoided # liter of fossil fuel (#) * Cost per liter of fossil fuel avoided (€)

This calculation monetizes the reduced CO2 emissions due to fuel savings. It is necessary to define the reduction of fleet mileage, the average consumption (liter/100km), the CO2 emissions per liter of fuel and a monetary value to CO2 emissions (€/metric ton of CO_2)

[5] Annex 7.10 to Commission Staff Working Document SEC(2011) 288 final — 'Impact Assessment': http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=SEC:2011:0288:FIN:EN:PDF

Benefit of reduced fossil fuel usage due to reduced fleet mileage of field personnel (e.g. truck rolls; meter reading operators):

*Value (€) = Avoided # liter of fossil fuel (#) * Cost of one liter of fossil fuel (€)*

For this calculation, it is necessary to define the reduction of fleet mileage, the average consumption (liter/100km) and the price (€/liter) of fossil fuel.

k. Reduction of air pollution (Particulate Matters, NOx, SO2)

For the 'cost of air pollutants' (particulate matters, NOx, SO2), it is recommended to consult the "CAFÉ" (Clean Air For Europe) air quality benefits' quantification process[6]. Other useful information can be found in [EC 2010d].

Reduced air pollutants emissions thanks to wider diffusion of low carbon generation sources (enabled by smart metering roll-out)

For each pollutant:

*Value (€) = [air pollutant Emissions (unit) * cost of air pollutant(€/unit)] $_{Baseline}$ — [air pollutant Emissions (unit) * cost of air pollutant(€/unit)] $_{Roll\text{-}out\ scenario}$*

Reduced air pollutants emissions thanks to reduced line losses

For each pollutant:

*Value (€) = [Line losses (MWh) * air pollutant content (unit/ MWh)* cost of air pollutant (€/unit)]$_{Baseline}$ -*

*Line losses (MWh) * air pollutant content (unit/MWh)* cost of air pollutant (€/unit)] $_{roll\text{-}out\ scenario}$*

Reduced air pollutants emissions due to lower fleet mileage of field personnel

For each pollutant:

[6] http://www.cafe-cba.org/assets/volume_2_methodology_overview_02-05.pdf

Value (€) = [fleet mileage (km)*air pollutant Emissions (unit/km) * cost of air pollutant(€/unit)] $_{\textit{Baseline}}$ ***— [fleet mileage (km)*air pollutant Emissions (unit/km) * cost of air pollutant(€/unit)]*** $_{\textit{Roll-out scenario}}$

For the cost of air pollutants specifically referred to vehicles (e.g. due to reduce mileage of truck rolls field personnel and of meter reading operators), it is recommended to consult the Clean Vehicles Directive - Directive 2009/33/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of clean and energy-efficient road transport vehicles.

ANNEX II – KEY PERFORMANCE INDICATORS AND BENEFITS FOR SMART GRIDS [EC TASK FORCE FOR SMART GRIDS, 2010c]

#	Benefits and KPIs
	Increased sustainability
1	Quantified reduction of carbon emissions
2	Environmental impact of electricity grid infrastructure
3	Quantified reduction of accidents and risk associated to generation technologies (during mining, production, installations, etc.)
	Adequate capacity of transmission and distribution grids for "collecting" and bringing electricity to the consumers
4	Hosting capacity for distributed energy resources in distribution grids
5	Allowable maximum injection of power without congestion risks in transmission networks
6	Energy not withdrawn from renewable sources due to congestion and/or security risks
7	An optimized use of capital and assets
	Adequate grid connection and access for all kind of grid users
8	first connection charges for generators, consumers and those that do both
9	grid tariffs for generators, consumers and those that do both
10	methods adopted to calculate charges and tariffs
11	time to connect a new user
12	optimisation of new equipment design resulting in best cost/benefit
13	faster speed of successful innovation against clear standards
	Satisfactory levels of security and quality of supply
14	Ratio of reliably available generation capacity and peak demand
15	Share of electrical energy produced by renewable sources
16	Measured satisfaction of grid users with the "grid" services they receive
17	Power system stability
18	Duration and frequency of interruptions per customer
19	Voltage quality performance of electricity grids (e.g. voltage dips, voltage and frequency deviations)

Enhanced efficiency and better service in electricity	
20	Level of losses in transmission and in distribution networks (absolute or percentage)[7]. Storage induces losses too, but also active flow control increases losses.
21	Ratio between minimum and maximum electricity demand within a defined time period (e.g. one day, one week)[8]
22	Percentage utilisation (i.e. average loading) of electricity grid elements
23	Demand side participation in electricity markets and in energy efficiency measures
24	Availability of network components (related to planned and unplanned maintenance) and its impact on network performances
25	Actual availability of network capacity with respect to its standard value (e.g. net transfer capacity in transmission grids, DER hosting capacity in distribution grids)
Effective support of transnational electricity markets by loadflow control to alleviate loopflows and increased interconnection capacities	
26	Ratio between interconnection capacity of one country/region and its electricity demand
27	Exploitation of interconnection capacities (ratio between monodirectional energy transfers and net transfer capacity), particularly related to maximisation of capacities according to the Regulation of electricity crossborder exchanges and the congestion management guidelines
28	Congestion rents across interconnections
29	Ratio between interconnection capacity of one country/region and its electricity demand
30	Exploitation of interconnection capacities (ratio between monodirectional energy transfers and net transfer capacity), particularly related to maximisation of capacities according to the Regulation of electricity crossborder exchanges and the congestion management guidelines
31	Congestion rents across interconnections
Coordinated grid development through common European, regional and local grid planning to optimize transmission grid infrastructure	
32	impact of congestion on outcomes and prices of national/regional markets

[7] In case of comparison, the level of losses should be corrected by structural parameters (e.g. by the presence of distributed generation in distribution grids and its production pattern). Moreover a possibly conflicting character of e.g. aiming at higher network elements' utilization (loading) vs. higher losses, should be considered accordingly.

[8] In case of comparison, a structural difference in the indicator should be taken into account due e.g. to electrical heating and weather conditions, shares of industrial and domestic loads.

33	societal benefit/cost ratio of a proposed infrastructure investment
34	overall welfare increase, i.e. running always the cheapest generators to supply the actual demand) (this is also an indicator for the benefit (6) above)
35	Time for licensing/authorisation of a new electricity transmission infrastructure.
36	Time for construction (i.e. after authorisation) of a new electricity transmission infrastructure.
Enhanced consumer awareness and participation in the market by new players	
37	Base to peak load ratio
38	Relation between power demand and market price for electricity
39	Consumers can comprehend their actual energy consumption and receive, understand and act on free information they need / ask for
40	Consumers are able to access their historic energy consumption information for free in a format that enables them to make like for like comparisons with deals available on the market.
41	Ability to participate in relevant energy market to purchase and/or sell electricity
42	Coherent link is established between the energy prices and consumer behaviour
Create a market mechanism for new energy services such as energy efficiency or energy consulting for customers	
43	'Simple' and/or automated changes to consumers' energy consumption in reply to demand/response signals, are enabled
44	Data ownership is clearly defined and data processes in place to allow for service providers to be active with customer consent
45	Physical grid related data are available in an accessible form
46	Transparency of physical connection authorisation, requirements and charges
47	Effective consumer complaint handling and redress. This includes clear lines of responsibility should things go wrong
Consumer bills are either reduced or upward pressure on them is mitigated	
48	Transparent, robust processes to assess whether the benefits of implementation exceed the costs in each area where rollout is considered are in place, and a commitment to act on the findings is ensured by all involved parties
49	Regulatory mechanisms exist, that ensure that these benefits are appropriately reflected in consumer bills and do not simply result in windfall profits for the industry
50	New smart tariffs (energy prices) deliver tangible benefits to consumers or society in a progressive way
51	Market design is compatible with the way the consumers use the grid

52	Transparent, robust processes to assess whether the benefits of implementation exceed the costs in each area where rollout is considered are in place, and a commitment to act on the findings is ensured by all involved parties
53	Regulatory mechanisms exist, that ensure that these benefits are appropriately reflected in consumer bills and do not simply result in windfall profits for the industry
54	New smart tariffs (energy prices) deliver tangible benefits to consumers or society in a progressive way
55	Market design is compatible with the way the consumers use the grid

ANNEX III AGREED COMMON-MINIMUM SMART METERING FUNCTIONALITIES (FOR THE CASE OF ELECTRICITY)[9]

Common minimum functional requirements

1. Every smart metering system for electricity should offer at least all the functionalities listed below:

For the customer:

(a) **Provide readings directly to the customer and any third party designated by the consumer.** This functionality is essential in a smart metering system, as direct consumer feedback is essential to ensure energy savings on the demand side. There is a significant consensus on provision of standardised interfaces which would enable energy management solutions in 'real time', such as home automation, and different demand response schemes and facilitate secure delivery of data directly to the customer. Accurate, user-friendly and timely readings provided directly from the interface of customer's choice to the customer and any third party designated by the consumer are strongly recommended since they are the key to running demand response services, taking 'on-line' energy-saving decisions and effective integration of distributed energy resources. In order to stimulate energy saving, Member States are strongly recommended to ensure that final customers using smart metering systems are equipped with a standardised interface which provides visualised individual consumption data to the consumer.

(b) **Update the readings referred to in point (a) frequently enough to allow the information to be used to achieve energy savings.** This functionality relates purely to the demand side, namely the end customer. If consumers are to rely on the information provided by the system, they need to see the information responding to their action. The rate has to be adapted to the response time of

---

[9] European Commission, 2011. "A joint contribution of DG ENER and DG INFSO towards the Digital Agenda, Action 73: Set of common functional requirements of the SMART METER", joint DG ENER-DG INFSO study, available from http://ec.europa.eu/energy/energy2020/smart_grid/index_en.htm

the energy-consuming or energy-producing products. The general consensus is that an update rate of every 15 minutes is needed at least. Further developments and new energy services are likely to lead to faster communications. It is also recommended that the smart metering system should be able to store customer consumption data for a reasonable time in order to allow the customer and any third party designated by the consumer to consult and retrieve data on past consumption. This should make it possible to calculate costs related to consumption.

For the metering operator:

(c) **Allow remote reading of meters by the operator.** This functionality relates to the supply side (metering operators). There is a broad consensus that this is a key functionality.

(d) **Provide two-way communication between the smart metering system and external networks for maintenance and control of the metering system**. This functionality relates to metering. There is a broad consensus that this is a key functionality.

(e) **Allow readings to be taken frequently enough for the information to be used for network planning**. This functionality relates to both the demand side and the supply side.

For commercial aspects of energy supply:

(f) **Support advanced tariff systems.** This functionality relates to both the demand side and the supply side. Smart metering systems should include advance tariff structures, time-of-use registers and remote tariff control. This should help consumers and network operators to achieve energy efficiencies and save costs by reducing the peaks in energy demand. This functionality, together with functionalities referred to in points (a) and (b), is a key driving force for empowering the consumer and for improving the energy efficiency of the supply system. It is strongly recommended that the smart metering system allows automatic transfer of information about advanced tariffs options to the final customers e.g. via standardised interface mentioned under a).

(g) **Allow remote on/off control of the supply and/or flow or power limitation.** This functionality relates to both the demand side and the supply side. It provides additional protection for the consumer by allowing grading in the limitations. It speeds up processes such as when moving home — the old supply can be disconnected and the new supply connected quickly and simply. It is needed for handling technical grid emergencies. It may, however, introduce additional security risks which need to be minimised.

For security and data protection:

(h) **Provide secure data communications.** This functionality relates to both the demand side and the supply side. High levels of security are essential for all communications between the meter and the operator. This applies both to direct communications with the meter and to any messages passed via the meter to or from any appliances or controls on the consumer's premises. For local communications within the consumer's premises, both privacy and data protection are required.

(i) **Fraud prevention and detection.** This functionality relates to the supply side: security and safety in the case of access. The strong consensus shows the importance attached to this functionality. This is necessary to protect the consumer, for example from hacking access, and not just for fraud prevention.

For distributed generation:

(j) **Provide import/export and reactive metering.** This functionality relates to both the demand side and the supply side. Most countries are providing the functionalities necessary to allow renewable and local micro-generation, thus future-proofing meter installation. It is recommended that this function should be installed by default and activated/disabled in accordance with the wishes and needs of the consumer.

ANNEX IV NON-EXHAUSTIVE LIST OF POTENTIAL BENEFITS FOR DIFFERENT MARKET ACTORS ON THE SMART METERING VALUE CHAIN [ERGEG 2011]

Consumers

- √ Better customer information
- √ Load shedding schemes
- √ Reduction of peak load
- √ Reduction of costs and delays of interventions
- √ Accurate consumption payment
- √ Damage/loss reduction
- √ New services
- √ Easier switching

Utilities

- √ Reduction of peak load
- √ Profiling and data aggregations
- √ Balancing
- √ System security
- √ Continuity of supply
- √ Faster fault location
- √ Voltage quality
- √ Network losses
- √ Reactive power
- √ Detection of fraud/theft
- √ Process optimization/savings of operational costs
- √ Improved investment and maintenance planning

Society as a whole

- √ Reduction of greenhouse gas emissions

Retailers and aggregators

- √ Better customer information
- √ Better frequency and quality of billing of data
- √ Improved load profiling and forecasting

ANNEX V – SMART GRID SERVICES AND FUNCTIONALITIES [EC TASK FORCE FOR SMART GRIDS, 2010a]

A. Enabling the network to integrate users with new requirements

Outcome: Guarantee the integration of distributed energy resources (both large and smallscale stochastic renewable generation, heat pumps, electric vehicles and storage) connected to the distribution network.

Provider: DSOs

Primary beneficiaries: Generators, consumers (including mobile consumers), storage owners.

Corresponding functionalities:

1. Facilitate connections at all voltages / locations for any kind of devices
2. Facilitate the use of the grid for the users at all voltages/locations
3. Use of network control systems for network purposes
4. Update network performance data on continuity of supply and voltage quality

B. Enhancing efficiency in day-to-day grid operation

Outcome: Optimize the operation of distribution assets and improve the efficiency of the network through enhanced automation, monitoring, protection and real time operation. Faster fault identification/resolution will help improve continuity of supply levels.

Better understanding and management of technical and nontechnical losses, and optimised asset maintenance activities based on detailed operational information.

Provider: DSOs, metering operators

Primary beneficiaries: Consumers, generators, suppliers, DSOs.

Corresponding functionalities:

5. Automated fault identification / grid reconfiguration reducing outage times
6. Enhance monitoring and control of power flows and voltages
7. Enhance monitoring and observability of grids down to low voltage levels
8. Improve monitoring of network assets

9. Identification of technical and non technical losses by power flow analysis
10. Frequent information exchange on actual active/reactive generation/consumption

C. Ensuring network security, system control and quality of supply

Outcome: Foster system security through an intelligent and more effective control of distributed energy resources, ancillary backup reserves and other ancillary services. Maximise the capability of the network to manage intermittent generation, without adversely affecting quality of supply parameters.

Provider: DSOs, aggregators, suppliers.

Primary beneficiaries: Generators, consumers, aggregators, DSOs, TSOs.

Corresponding functionalities:

11. Allow grid users and aggregators to participate in ancillary services market
12. operation schemes for voltage/current control
13. Intermittent sources of generation to contribute to system security
14. System security assessment and management of remedies
15. Monitoring of safety particularly in public areas
16. Solutions for demand response for system security in required time

D. Better planning of future network investment

Outcome: Collection and use of data to enable more accurate modeling of networks especially at LV level, also taking into account new grid users, in order to optimise infrastructure requirements and so reduce their environmental impact. Introduction of new methodologies for more 'active' distribution, exploiting active and reactive control capabilities of distributed energy resources.

Provider: DSOs, metering operators.

Primary beneficiaries: Consumers, generators, storage owners.

Corresponding functionalities:

17. Better models of DG, storage, flexible loads, ancillary services
18. Improve asset management and replacement strategies
19. Additional information on grid quality and consumption by metering for planning

E. Improving market functioning and customer service

Outcome: Increase the performance and reliability of current market processes through improved data and data flows between market participants, and so enhance customer experience.

Provider: Suppliers (with applications and services providers), power exchange platform providers, DSOs, metering operators.

Primary beneficiaries: Consumers, suppliers, applications and services providers.

Corresponding functionalities:

20. Participation of all connected generators in the electricity market
21. Participation of VPPs and aggregators in the electricity market
22. Facilitate consumer participation in the electricity market
23. Open platform (grid infrastructure) for EV recharge purposes
24. Improvement to industry systems (for settlement, system balance, scheduling)
25. Support the adoption of intelligent home / facilities automation and smart devices
26. Provide to grid users individual advance notice for planned interruptions
27. Improve customer level reporting in occasion of interruptions

F. Enabling and encouraging stronger and more direct involvement of consumers in their energy usage and management

Outcome: Foster greater consumption awareness taking advantage of smart metering systems and improved customer information, in order to allow consumers to modify their behaviour according to price and load signals and related information.

Promote the active participation of all actors to the electricity market, through demand response programmes and a more effective management of the variable and nonprogrammable generation. Obtain the consequent system benefits: peak reduction, reduced network investments, ability to integrate more intermittent generation.

Provider: Suppliers (with metering operators and DSOs), ESCOs.

Primary beneficiaries: Consumers, generators.

The only primary beneficiary which is present in all services is the consumer. Indeed, consumers will benefit:

either because these services will contribute to the 20/20/20 targets

or directly through improvement of quality of supply and other services

The hypothesis made here is that company efficiency and the benefit of the competitive market will be passed to consumers– at least partly in the form of tariff or price optimisation, and is dependent on effective regulation and markets.

Corresponding functionalities:

28. Sufficient frequency of meter readings
29. Remote management of meters
30. Consumption/injection data and price signals by different means
31. Improve energy usage information
32. Improve information on energy sources
33. Availability of individual continuity of supply and voltage quality indicators

ANNEX VI – ASSETS/FUNCTIONALITIES MATRIX (CBA STEP 2)

	Services and Functionalities																																
	Integrate users with new requirements				Enhancing efficiency in day-to-day grid operation						Ensuring network security, system control and quality of supply						Better planning of future network investment			Improving market functioning and customer service								More direct involvement of consumers in their energy usage					
	1. Facilitate connections at all voltages / locations for any kind of devices	2. Facilitate the use of the grid for the users at all voltages/locations	3. Use of network control systems for network purposes	4. Update network performance data on continuity of supply and voltage quality	5. Automated fault identification / grid reconfiguration reducing outage times	6. Enhance monitoring and control of power flows and voltages	7. Enhance monitoring and observability of grids down to low voltage levels	8. Improve monitoring of network assets	9. Identification of technical and non-technical losses by power flow analysis	10. Frequent information exchange on actual active/reactive generation/consumption	11. Allow grid users and aggregators to participate in ancillary services market	12. operation schemes for voltage/current control	13. Intermittent sources of generation to contribute to system security	14. System security assessment and management of remedies	15. Monitoring of safety particularly in public areas	16. Solutions for demand response for system security in required time	17. Better models of DG, storage, flexible loads, ancillary services	18. Improve asset management and replacement strategies	19. Additional information on grid quality and consumption by metering for planning	20. Participation of all connected generators in the electricity market	21. Participation of VPPs and aggregators in the electricity market	22. Facilitate consumer participation in the electricity market	23. Open platform (grid infrastructure) for EV recharge purposes	24. Improvement to industry systems (for settlement, system balance, scheduling)	25. Support the adoption of intelligent home / facilities automation and smart devices	26. Provide to grid users individual advance notice for planned interruptions	27. Improve customer level reporting in occasion of interruptions	28. Sufficient frequency of meter readings	29. Remote management of meters	30. Consumption/injection data and price signals by different means	31. Improve energy usage information	32. Improve information on energy sources	33. Availability of individual continuity of supply and voltage quality indicators
SCENARIO ASSETS																																	

ANNEX VII –BENEFITS/FUNCTIONALITIES MATRIX (CBA STEP 3)

			Services and functionalities (ANNEX V)		
			Functionality 1	…	Functionality 33
EPRI BENEFITS [EPRI 2010]	Economic	Optimized Generator Operation			
		Deferred Generation Capacity Investments			
		Reduced Ancillary Service Cost			
		Reduced Congestion Cost			
		Deferred Transmission Capacity Investments			
		Deferred Distribution Capacity Investments			
		Reduced Equipment Failures			
		Reduced Distribution Equipment Maintenance Cost			
		Reduced Distribution Operation Cost			
		Reduced Meter Reading Cost			
		Reduced Electricity Theft			
		Reduced Electricity Losses			
		Detection of anomalies relating Contracted Power			
		Reduced Electricity Cost			
	Reliability	Reduced Sustained Outages			
		Reduced Major Outages			
		Reduced Restoration Cost			
		Reduced Momentary Outages			
		Reduced Sags and Swells			
	Environmental	Reduced CO2 Emissions			
		Reduced Sox, Nox, and PM-10 Emissions			
	Security	Reduced Oil Usage			
		Reduced Wide-scale Blackouts			

ANNEX VIII- MERIT DEPLOYMENT MATRIX [EC TASK FORCE FOR SMART GRIDS, 2010c]

		Services and functionalities (ANNEX V)			
		Functionality 1	…	Functionality 33	Total sum - rows
Benefits and Key performance indicators (ANNEX II)	KPI 1				Sum row 1
	…				
	KPI 55				Sum row 55
	Total sum-columns	Sum column 1	…	Sum column 33	

ANNEX IX – GLOSSARY OF CBA TERMS

Benefit-cost ratio: the net present value of project benefits divided by the net present value of project costs. A project is accepted if the benefit-cost ratio is equal to or greater than one. It is used to accept independent projects, but it may give incorrect rankings and often cannot be used for choosing among mutually exclusive alternatives.

Cost-Benefit analysis: conceptual framework applied to any systematic, quantitative appraisal of a public or private project to determine whether, or to what extent, that project is worthwhile from a social perspective. Cost-benefit analysis differs from a straightforward financial appraisal in that it considers all gains (benefits) and losses (costs) to social agents. CBA usually implies the use of accounting prices.

Discount rate - The interest rate used in discounted cash flow analysis to determine the present value of future cash flows. The discount rate takes into account the time value of money (the idea that money available now is worth more than the same amount of money available in the future because it could be earning interest) and the risk or uncertainty of the anticipated future cash flows (which might be less than expected).

Discounting: the process of adjusting the future values of project inflows and outflows to present values using a discount rate, i.e. by multiplying the future value by a coefficient that decreases with time.

Do nothing: the baseline scenario, 'business as usual', against which the additional benefits and costs of the 'with project scenario' can be measured (often a synonym for the 'without project' scenario).

Economic analysis: analysis that is undertaken using economic values, reflecting the values that society would be willing to pay for a good or service. In general, economic analysis values all items at their value in use or their opportunity cost to society (often a border price for tradable items). It has the same meaning as social cost-benefit analysis.

Externality: an externality is said to exist when the production or consumption of a good in one market affects the welfare of a third party without any payment or compensation being made. In project analysis, an externality is an effect of a project not reflected in its financial accounts and consequently not included in the valuation. Externalities may be positive or negative.

Ex-ante evaluation: the evaluation carried out in order to take the investment decision. It serves to select the best option from the socio economic and financial point of view. It provides the necessary base for the monitoring and subsequent evaluations ensuring that, wherever possible, the objectives are quantified.

Ex-post evaluation: an evaluation carried out a certain length of time after the conclusion of the initiative. It consists of describing the impact achieved by the initiative compared to the overall objectives and project purpose (ex-ante).

Financial analysis: the analysis carried out from the point of view of the project operator. It allows one to 1) verify and guarantee cash balance (verify the financial sustainability), 2) calculate the indices of financial return on the investment project based on the net time-discounted cash flows, related exclusively to the economic entity that activates the project (firm, managing agency).

Impact: a generic term for describing the changes or the long term effects on society that can be attributed to the project. Impacts should be expressed in the units of measurement adopted to deal with the objectives to be addressed by the project.

Internal rate of return: the discount rate at which a stream of costs and benefits has a net present value of zero. The internal rate of return is compared with a benchmark in order to evaluate the performance of the proposed project. Financial Rate of Return is calculated using financial values, Economic rate of Return is calculated using economic values.

Investment cost (CAPEX): capital cost incurred in the construction of the project.

Net Present Value (NPV): the sum that results when the discounted value of the expected costs of an investment are deducted from the discounted value of the expected revenues.

Non-monetised costs Costs that cannot easily be attributed a euro value, they are sometimes difficult to measure due to the absence of market signals, but represent the estimated value of adverse or positive impacts from the project option (e.g. pollution effects)

Off peak: Period of relatively low system demand. These periods often occur in daily, weekly, and seasonal patterns; these off-peak periods differ for each individual electric utility.

On peak: Periods of relatively high system demand. These periods often occur in daily, weekly, and seasonal patterns; these on-peak periods differ for each individual electric utility.

Operating costs (OPEX): cost incurred in the operation of an investment, including cost of routine and extraordinary maintenance but excluding depreciation or capital costs.

Peak load transfer: the share of electricity usage that is shifted from peak periods (the highest point of customer consumption of electricity) to off-peak periods

Project: An investment activity upon which resources (costs) are expended to create capital assets that will produce benefits over an extended period of time. A project is thus a specific activity, with a specific starting point and a specific ending point, that is intended to accomplish a specific objective. It can also be thought of as the smallest operational element prepared and implemented as a separate entity in a national plan or program.

Rate of return: The ratio of net operating income earned by a utility calculated as a percentage of its rate base.

Reference period: the number of years for which forecasts are provided in the cost-benefit analysis. Generally, the time period used for economic and financial analysis is the economic/financial life of the project over which all costs and benefits are assessed. The implementation period, initial period of the capital investment and the subsequent period over which the benefits of the project accrue are included in the project time period.

Scenario analysis: a variant of sensitivity analysis that studies the combined impact of determined sets of values assumed by the critical variables. It does not substitute the item-by-item sensitivity analysis.

Sensitivity analysis: the analytical technique to test systematically what happens to a project's earning capacity if events differ from the estimates made in planning. It is a rather crude means of dealing with uncertainty about future events and values. It is carried out by varying one item and then determining the impact of that change on the outcome.

Social discount rate (public policy discount rate): to be contrasted with the financial discount rate. It attempts to reflect the social view on how the future should be valued against the present.

Socio-economic costs and benefits: opportunity costs or benefits for the economy as a whole. They may differ from private costs and benefits to the extent that actual prices differ from accounting prices.

Sunk costs: An expenditure that has been incurred in the past and cannot be recovered.

Transmission and distribution loss: Electric energy lost due to the transmission and distribution of electricity.

European Commission

EUR 25103 EN – Joint Research Centre – Institute for Energy and Transport
Title: Guidelines for Cost Benefit Analysis of Smart Metering Deployment
Author(s): Vincenzo Giordano, Ijeoma Onyeji, Gianluca Fulli (JRC IET)
Manuel Sánchez Jiménez, Constantina Filiou (DG ENER)
Luxembourg: Publications Office of the European Union
2012 – 84 pp. – 21.0 x 29.7 cm
EUR – Scientific and Technical Research series – ISSN 1831-9424

ISBN 978-92-79-22323-5

doi:10.2790/39435

Abstract
The present document provides a methodological framework for conducting a cost-benefit analysis of smart meter deployment. The assessment framework is structured into a set of guidelines to tailor assumptions to local conditions, to identify and monetize benefits and costs, and to perform sensitivity analysis of most critical variables. It also provides guidance in the identification of externalities and social impacts that can result from the implementation of smart metering deployment but that cannot be easily monetized and factored into the cost benefit computation.

This document is mainly intended to support Member States in fulfilling the provisions of the 3rd Energy Package on CBA of smart metering deployment.

LD-NA-25103-EN-N

The mission of the JRC is to provide customer-driven scientific and technical support for the conception, development, implementation and monitoring of EU policies. As a service of the European Commission, the JRC functions as a reference centre of science and technology for the Union. Close to the policy-making process, it serves the common interest of the Member States, while being independent of special interests, whether private or national.

JRC SCIENTIFIC AND TECHNICAL RESEARCH

ISBN 978-92-79-22323-5

Publications Office